2017

United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 40-F

☐ **Registration Statement pursuant to section 12 of the Securities Exchange Act of 1934**

☒ **Annual report pursuant to section 13(a) or 15(d) of the Securities Exchange Act of 1934**

For the fiscal year ended December 31, 2017

Commission File Number: 001-04307

Husky Energy Inc.
(Exact name of Registrant as specified in its charter)

Alberta, Canada	1311	Not Applicable
(Province or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number (if applicable))	(I.R.S. Employer Identification Number (if applicable))

707-8th Avenue S.W. Calgary, Alberta, Canada T2P 1H5
(403) 298-6111
(Address and telephone number of Registrant's principal executive office)

CT Corporation System, 111 Eighth Avenue, New York, New York 10011
(877) 467-3525
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Securities registered or to be registered pursuant to Section 12(b) of the Act:
Title of Class: None

Securities registered or to be registered pursuant to Section 12(g) of the Act:
Title of Class: None

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:
Title of Class: Common Shares

For annual reports, indicate by check mark the information filed with this Form:

☒ **Annual information form** ☒ **Audited annual financial statements**

Number of outstanding shares of each of the issuer's classes of capital or common stock as of the close of the period covered by the annual report:

1,005,120,012 Common Shares outstanding as of December 31, 2017

10,435,932 Cumulative Redeemable Preferred Shares, Series 1 outstanding as of December 31, 2017

1,564,068 Cumulative Redeemable Preferred Shares, Series 2 outstanding as of December 31, 2017

10,000,000 Cumulative Redeemable Preferred Shares, Series 3 outstanding as of December 31, 2017

8,000,000 Cumulative Redeemable Preferred Shares, Series 5 outstanding as of December 31, 2017

6,000,000 Cumulative Redeemable Preferred Shares, Series 7 outstanding as of December 31, 2017

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

Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (s.232.405 of this chapter) during the preceding 12 months (or for such shorter period that the Registrant was required to submit and post such files).

Yes ☒ No ☐

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 12b-2 of the Exchange Act.

Emerging growth company ☐

If an emerging growth company that prepares its financial statements in accordance with U.S. GAAP, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards† provided pursuant to Section 13(a) of the Exchange Act. ☐

This Annual Report on Form 40-F shall be incorporated by reference into or as an exhibit to, as applicable, the Registrant's Registration Statement under the Securities Act of 1933: Form F-10 (File No. 333-222652); Form S-8 (File No. 333-187135).

† The term "new or revised financial accounting standard" refers to any update issued by the Financial Accounting Standards Board to its Accounting Standards Codification after April 5, 2012.

Principal Documents

The following documents have been filed as part of this Annual Report on Form 40-F:

A. Annual Information Form

The Annual Information Form ("AIF") of Husky Energy Inc. ("Husky" or the "Company") for the year ended December 31, 2017 is included as Document A of this Annual Report on Form 40-F.

B. Audited Annual Financial Statements

Husky's audited consolidated financial statements for the years ended December 31, 2017 and December 31, 2016, including the auditors' report with respect thereto, are included as Document B of this Annual Report on Form 40-F.

C. Management's Discussion and Analysis

Husky's Management's Discussion and Analysis for the year ended December 31, 2017 is included as Document C of this Annual Report on Form 40-F.

Certifications

See Exhibits 31.1, 31.2, 32.1 and 32.2, which are included as Exhibits to this Annual Report on Form 40-F.

Supplemental Reserves Information

See Exhibit 99.1 for the Supplemental Reserves Information, which is included as an Exhibit to this Annual Report on Form 40-F.

Disclosure Controls and Procedures

See the section "Disclosure Controls and Procedures" in Husky's Management's Discussion and Analysis for the year ended December 31, 2017, which is included as Document C of this Annual Report on Form 40-F.

Management's Annual Report on Internal Control Over Financial Reporting

See the section "Disclosure Controls and Procedures" in Husky's Management's Discussion and Analysis for the year ended December 31, 2017, which is included as Document C of this Annual Report on Form 40-F.

Attestation Report of the Independent Registered Public Accounting Firm

See the "Report of Independent Registered Public Accounting Firm" that accompanies Husky's audited consolidated financial statements for the years ended December 31, 2017 and 2016, which is included as Document B of this Annual Report on Form 40-F.

Changes in Internal Control Over Financial Reporting

See the section "Disclosure Controls and Procedures" in Husky's Management's Discussion and Analysis for the year ended December 31, 2017, which is included as Document C of this Annual Report on Form 40-F.

Notice Pursuant to Regulation BTR

Not Applicable.

Audit Committee Financial Expert

The Board of Directors of Husky has determined that William Shurniak is an "audit committee financial expert" (as defined in paragraph 8(b) of General Instruction B to Form 40-F) serving on its Audit Committee. Pursuant to paragraph 8(a)(2) of General Instruction B to Form 40-F, the Board has applied the definition of independence applicable to the audit committee members of New York Stock Exchange listed companies, although the Company's securities are not listed on a U.S. stock exchange. Mr. Shurniak is a corporate director and is independent under the New York Stock Exchange standards. For a description of Mr. Shurniak's relevant experience in financial matters, see Mr. Shurniak's history in the section "Directors and Officers" and in the section "Audit Committee" in Husky's AIF for the year ended December 31, 2017, which is included as Document A of this Annual Report on Form 40-F.

Code of Business Conduct and Ethics

Husky's Code of Ethics is disclosed in its Code of Business Conduct, which is applicable to its principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions and to all of its other employees, and is posted on its website at www.huskyenergy.com. On February 23, 2017, Husky amended its Code of Business Conduct effective as of February 24, 2017, and a copy of this new amended Code of Business Conduct is included as Exhibit 99.2 to this Annual Report on Form 40-F for the fiscal year ended December 31, 2017. A copy of such amended Code of Business Conduct was posted on Husky's website (together with a disclosure of the nature of the amendment) promptly after the amendment became effective. In the fiscal year ended December 31, 2017, Husky has not granted a waiver, including an implicit waiver, from a provision of its Code of Ethics to any of its principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions that relates to one or more of the items set forth in paragraph (9)(b) of General Instruction B to Form 40-F. In the event that, during Husky's ensuing fiscal year, Husky:

i. amends any provision of its Code of Business Conduct that applies to its principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions that relates to any element of the code of ethics definition enumerated in paragraph (9)(b) of General Instruction B to Form 40-F; or

ii. grants a waiver, including an implicit waiver, from a provision of its Code of Business Conduct to any of its principal executive officer, principal financial officer, principal accounting officer or controller or persons performing similar functions that relates to one or more of the items set forth in paragraph (9)(b) of General Instruction B to Form 40-F;

Husky will promptly disclose such occurrences on its website following the date that such amendment or waiver is granted and will specifically describe the nature of any amendment or waiver, and in the case of a waiver, name the person to whom the waiver was granted and the date of the waiver, in each case as further described in paragraph (9) of General Instruction B to Form 40-F.

Principal Accountant Fees and Services

See the section "External Auditor Service Fees" in Husky's AIF for the year ended December 31, 2017, which is included as Document A of this Annual Report on Form 40-F.

Off-Balance Sheet Arrangements

See the section "Contractual Obligations, Commitments and Off-Balance Sheet Arrangements" in Husky's Management's Discussion and Analysis for the year ended December 31, 2017, which is included as Document C of this Annual Report on Form 40-F.

Tabular Disclosure of Contractual Obligations

See the section "Contractual Obligations, Commitments and Off-Balance Sheet Arrangements" in Husky's Management's Discussion and Analysis for the year ended December 31, 2017, which is included as Document C of this Annual Report on Form 40-F.

Interactive Data File

See Exhibit 101 to this Annual Report on Form 40-F for the fiscal year ended December 31, 2017.

Mine Safety Disclosure

Not applicable.

Undertaking and Consent to Service of Process

Undertaking

Husky undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the Commission staff, and to furnish promptly, when requested to do so by the Commission staff, information relating to: the securities in relation to which the obligation to file an annual report on Form 40-F arises; or transactions in said securities.

Consent to Service of Process

A Form F-X signed by Husky and its agent for service of process has been filed with the Commission together with Form F-10 (File No. 333-222652) in connection with its securities registered on such form.

Any change to the name or address of the agent for service of process of Husky shall be communicated promptly to the Commission by an amendment to the Form F-X referencing the file number of Husky.

Signatures

Pursuant to the requirements of the Exchange Act, Husky Energy Inc. certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this Annual Report to be signed on its behalf by the undersigned, thereto duly authorized.

Dated this 1st day of March, 2018

Husky Energy Inc.

By: /s/ Robert J. Peabody
Name: Robert J. Peabody
Title: President & Chief Executive Officer

By: /s/ James D. Girgulis
Name: James D. Girgulis
Title: Senior Vice President, General Counsel & Secretary

Annual Information Form

For the Year Ended December 31, 2017

Husky Energy

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2017

MARCH 1, 2018

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NOTE TO READER

Unless otherwise indicated, in this Annual Information Form ("AIF"), the terms "Husky" and the "Company" mean Husky Energy Inc. and its subsidiaries and partnership interests on a consolidated basis, including information with respect to predecessor corporations.

Unless otherwise indicated, the information contained in this AIF is presented as at or for the year ended December 31, 2017, and all financial information included and incorporated by reference in this AIF is determined using International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board.

Except where otherwise indicated, all dollar amounts stated in this AIF are in Canadian dollars.

See also "Reader Advisories" on page 80 of this AIF.

ABBREVIATIONS AND GLOSSARY OF TERMS

When used in this AIF, the following terms have the meanings indicated:

Units of Measure	
bbl	barrel
bbls	barrels
bbls/day	barrels per calendar day
bcf	billion cubic feet
boe	barrels of oil equivalent
boe/day	barrels of oil equivalent per calendar day
GJ	gigajoule
kt	kilotonne
long tons/day	imperial measurement of a metric tonne per calendar day
m^3	cubic metres
mbbls	thousand barrels
mbbls/day	thousand barrels per calendar day
mboe	thousand barrels of oil equivalent
mboe/day	thousand barrels of oil equivalent per calendar day
mcf	thousand cubic feet
mmbbls	million barrels
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/day	million cubic feet per calendar day
tcf	trillion cubic feet
tCO_2e	tonnes of carbon dioxide equivalent

abandonment and reclamation costs

All costs associated with the process of restoring Husky's properties that have been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities, including costs associated with the retirement of upstream and downstream assets which consist primarily of plugging and abandoning wells, abandoning surface and subsea plant, equipment and facilities, and restoring land.

API gravity

Measure of oil density or specific gravity used in the petroleum industry. The API scale expresses density such that the greater the density of the petroleum, the lower the degree of API gravity.

barrel

A unit of volume equal to 42 U.S. gallons.

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.

BP-Husky Toledo Refinery

The crude oil refinery owned 50 percent by the Company and 50 percent by BP Corporation North America Inc. and located in Toledo, Ohio.

CO_2e

Carbon dioxide equivalent.

development well

A well drilled within the proved area of an oil and gas reservoir to the depth of a stratigraphic horizon known to be productive.

diluent

A lighter gravity liquid hydrocarbon, usually condensate or synthetic oil, added to heavy oil and bitumen to facilitate the transmissibility of the oil through a pipeline.

enhanced oil recovery

The increased recovery from a crude oil pool achieved by artificial means or by the application of energy extrinsic to the pool. An artificial means or application includes pressuring, cycling, pressure maintenance or injection to the pool of a substance or form of energy but does not include the injection in a well of a substance or form of energy for the sole purpose of aiding in the lifting of fluids in the well, or stimulation of the reservoir at or near the well by mechanical, chemical, thermal or explosive means.

exploration licence

A licence with respect to the Canadian offshore or the Northwest Territories conferring the right to explore for, and the exclusive right to drill and test for, hydrocarbons and petroleum, the exclusive right to develop the applicable area in order to produce petroleum and, subject to satisfying the requirements for issuance of a production licence and compliance with the terms of the licence and other provisions of the relevant legislation, the exclusive right to obtain a production licence.

exploration well

A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or gas. Generally, an exploration well is any well that is not a development well, a service well, an extension well, which is a well drilled to extend the limits of a known reservoir, or a stratigraphic test well as those terms are defined herein.

feedstock

Raw materials which are processed into petroleum products.

field

An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or by both.

gross/net acres and gross/net wells

Gross refers to the total number of acres or wells, as the context requires, in which a working interest is owned. Net refers to the sum of the fractional working interests owned by a company.

gross reserves and gross production

A company's working interest share of reserves or production, as the context requires, 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 one are referred to as high-TAN crudes.

light crude oil

Crude oil with a relative density greater than 31.1 degrees API gravity.

Lima Refinery

The crude oil refinery owned by the Company and located in Lima, Ohio.

liquefied petroleum gas

Liquefied propanes and butanes, separately or in mixtures.

medium crude oil

Crude oil with a relative density greater than 22.3 degrees API gravity and less than or equal to 31.1 degrees API gravity.

natural gas

Natural gas is a naturally occurring hydrocarbon gas mixture consisting primarily of methane, but commonly including varying amounts of other higher alkanes, and sometimes a small percentage of carbon dioxide, nitrogen and/or hydrogen sulfide.

natural gas liquids

Those hydrocarbon components recovered from raw natural gas as liquids by processing through extraction plants, or recovered from field separators, scrubbers or other gathering facilities. These liquids include the hydrocarbon components ethane, propane and butane and condensates and combinations thereof.

net revenue

Gross revenues less royalties.

oil sands

Sands and other rock materials that contain bitumen and all other mineral substances in association therewith.

operating netback

Gross revenue less production, operating and transportation costs and royalties on a per unit basis.

petroleum coke

A carbonaceous solid delivered from oil refinery coker units or other cracking processes.

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.

Prince George Refinery

The light oil refinery owned by the Company and located in Prince George, British Columbia.

production licence

Confers, with respect to the portions of the offshore area to which the licence applies, the right to explore for, and the exclusive right to drill and test for, petroleum, the exclusive right to develop those portions of the offshore area in order to produce petroleum, the exclusive right to produce petroleum from those portions of the offshore area and title to the petroleum produced.

production sharing contract

A contract for the development of resources under which the contractor’s costs (investment) are recoverable each year out of the production but with a maximum amount of production that can be applied to the cost recovery in any year.

Scope 1 emissions

Direct emissions from sources that are owned or controlled by the Company, as prescribed by the U.S. Environmental Protection Agency.

Scope 2 emissions

Indirect emissions from sources that are owned or controlled by the Company, as prescribed by the U.S. Environmental Protection Agency.

secondary recovery

Oil or gas recovered by injecting water or gas into the reservoir to force additional oil or gas to the producing wells. Usually, but not necessarily, this is done after the primary recovery phase has passed.

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.

service well

A well drilled or completed for the purpose of supporting production in an existing field. Specific purposes of service wells include gas injection, water injection, steam injection, air injection, saltwater disposal, water supply for injection, observation or injection for in-situ combustion.

significant discovery declaration

A discovery indicated by the first well on a geological feature that demonstrates by flow testing the existence of hydrocarbons in that feature and, having regard to geological and engineering factors, suggests the existence of an accumulation of hydrocarbons that has potential for sustained production.

significant discovery licence

The document of "title" by which an interest owner can continue to hold rights to a discovery area while the extent of that discovery is determined and, if it has potential to be brought into commercial production in the future, until commercial development becomes viable. A significant discovery licence is effective from the application date and remains in force for so long as the relevant declaration of significant discovery is in force, or until a production licence is issued for the relevant lands.

spot price

The price for a one-time open market transaction for immediate delivery of a specific quantity of product at a specific location where the commodity is purchased "on the spot" at current market rates.

steam-assisted gravity drainage

An enhanced oil recovery method used to produce heavy crude oil and bitumen in-situ. Steam is injected via a horizontal well along a producing formation. The temperature in the formation increases and lowers the viscosity of the crude oil allowing it to fall into a horizontal production well beneath the steam injection well.

stratigraphic test well

A hole drilled to delineate or derisk the geology, and may include the cutting of cores, to aid in exploring and developing for oil and gas and usually drilled without the intent of being completed for production.

sulphur

An element that occurs in natural gas and petroleum.

Superior Refinery

The crude oil refinery owned by the Company and located in Superior, Wisconsin.

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 the heavy oil and bitumen to flow to the well bore.

turnaround

Performance of plant or facility maintenance.

Upgrader

The heavy oil upgrading facility owned and operated by the Company and located in Lloydminster, Saskatchewan.

waterflood

One method of secondary recovery in which water is injected into an oil reservoir for the purpose of forcing oil out of the reservoir and into the bore of a producing well.

wellhead

The structure, sometimes called the "Christmas tree",that is positioned on the surface over a well and used to control the flow of oil or gas as it emerges from the subsurface casing head.

working interest

A percentage of ownership in an oil and gas lease granting its owners the right to explore, drill and produce oil and gas from a property.

2-D seismic survey

Two-dimensional seismic imaging uses seismic wave data recorded on one receiver line on the ground, to output a single cross-section of seismic data that is used to detect geologic variations in the subsurface.

3-D seismic survey

Three-dimensional seismic imaging uses seismic wave data recorded simultaneously on a series of parallel receiver lines on the ground, to output a three-dimensional volume of seismic data that is used to detect geologic variations in the subsurface.

2015 Canadian Shelf Prospectus

The universal short form base shelf prospectus filed by the Company on February 23, 2015 with applicable securities regulators in each of the provinces of Canada.

EXCHANGE RATE INFORMATION

The following table discloses various indicators of the Canadian dollar/U.S. dollar rate of exchange or the cost of a U.S. dollar in Canadian currency for the three years indicated.

	Year ended December 31,		
Exchange Rate Information *(Cdn$ per US$)*	**2017**	2016	2015
Year-end[(1)]	**1.252**	1.343	1.384
Low	**1.213**	1.254	1.173
High	**1.374**	1.459	1.399
Average	**1.298**	1.325	1.279

(1) The year-end exchange rate for 2017 was quoted by the Thomson Reuters WM/R for the noon rate at the last day of the relevant period. The year-end exchange rates for 2016 and 2015 were as quoted by the Bank of Canada for the noon buying rate as at the last day of the relevant period. The Bank of Canada discontinued the publication of the noon buying rates during 2017. The high, low and average rates were either quoted or calculated within each of the relevant periods.

CORPORATE STRUCTURE

Incorporation and Organization

Husky Energy Inc. was incorporated under the Business Corporations Act (Alberta) on June 21, 2000. The Company's Articles were amended effective February 28, 2011 to permit the issuance of common shares as payment of stock dividends on the common shares and to authorize preferred shares to be issued in one or more series. The Company's Articles were amended: effective March 11, 2011, to create Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Preferred Shares") and Cumulative Redeemable Preferred Shares, Series 2 (the "Series 2 Preferred Shares"); effective December 4, 2014, to create Cumulative Redeemable Preferred Shares, Series 3 (the "Series 3 Preferred Shares") and Cumulative Redeemable Preferred Shares, Series 4 (the "Series 4 Preferred Shares"); effective March 9, 2015, to create Cumulative Redeemable Preferred Shares, Series 5 (the"Series 5 Preferred Shares") and Cumulative Redeemable Preferred Shares, Series 6 (the "Series 6 Preferred Shares"); and effective June 15, 2015, to create Cumulative Redeemable Preferred Shares, Series 7 (the "Series 7 Preferred Shares") and Cumulative Redeemable Preferred Shares, Series 8 (the "Series 8 Preferred Shares").

Husky's registered office and head and principal office are located at 707 - 8th Avenue S.W., Calgary, Alberta, T2P 1H5.

Intercorporate Relationships

The following table lists Husky's significant subsidiaries and jointly-controlled entities and their respective places of incorporation, continuance or organization, as the case may be, as at December 31, 2017. [(1)] All of the entities listed below, except as otherwise indicated, are 100 percent beneficially owned, or controlled or directed, directly or indirectly, by Husky.

Significant Subsidiaries and Joint Operations	Jurisdiction
Husky Oil Operations Limited	Alberta
Husky Energy International Corporation	Alberta
Lima Refining Company	Delaware
Husky Marketing and Supply Company	Delaware
Husky Oil Limited Partnership	Alberta
Husky Terra Nova Partnership	Alberta
Husky Downstream General Partnership	Alberta
Husky Energy Marketing Partnership	Alberta
Sunrise Oil Sands Partnership (50 percent)	Alberta
BP-Husky Refining LLC (50 percent)	Delaware

(1) Principal operating subsidiaries exclusive of intercorporate relationships due to financing related receivables and financing investments.

GENERAL DEVELOPMENT OF HUSKY

Three-year History of Husky

The following is a description of how Husky's business has developed over the last three completed financial years.

2015

On February 23, 2015, the Company filed the 2015 Canadian Shelf Prospectus, which enabled 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 March 23, 2017.

On March 11, 2015, the Company announced that it had started oil production at the Sunrise Energy Project in northern Alberta.The project is being developed in multiple phases with Phase 1 consisting of two 30,000 bbls/day bitumen plants (Plants 1A and 1B).

On March 12, 2015, the Company issued $750 million of 3.55 percent notes due March 12, 2025 by way of a prospectus supplement dated March 9, 2015 to the 2015 Canadian Shelf Prospectus. 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 12 and September 12 of each year, beginning September 12, 2015. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On March 12, 2015, the Company issued 8 million Series 5 Preferred Shares at a price of $25.00 per share, for aggregate gross proceeds of $200 million, by way of a prospectus supplement dated March 5, 2015 to the 2015 Canadian Shelf Prospectus. Holders of the Series 5 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending March 31, 2020 as declared by the Board of Directors. See "Dividends – Dividend Policy and Restrictions – Series 5 Preferred Share Dividends".

On June 17, 2015, the Company issued 6 million Series 7 Preferred Shares at a price of $25.00 per share, for aggregate gross proceeds of $150 million, by way of a prospectus supplement dated June 10, 2015 to the 2015 Canadian Shelf Prospectus. Holders of the Series 7 Preferred Shares are entitled to receive a cumulative fixed dividend yielding 4.60 percent annually for the initial period ending June 30, 2020 as declared by the Board of Directors. See "Dividends – Dividend Policy and Restrictions – Series 7 Preferred Share Dividends".

On June 29, 2015, the Company announced that it had started production from the South White Rose project in the Jeanne d'Arc Basin offshore Newfoundland and Labrador ("NL").

On July 16, 2015, the Company announced that it had started production at the 10,000 bbls/day Rush Lake Thermal Project in Saskatchewan.

On September 8, 2015, the Company announced that it had commenced production from a second oil well at the South White Rose project in the Jeanne d'Arc Basin offshore NL.

On October 6, 2015, the Company announced that it had entered into an agreement with Imperial Oil to create a single expanded truck transport network of approximately 160 sites in Canada.

On October 30, 2015, the Board of Directors approved an amendment to the Company's dividend policy and the Company announced that the third quarter 2015 dividend would be paid in the form of common shares as an interim measure in lieu of paying a cash dividend. Given the persistent downward pressure on oil prices and the extended lower for longer outlook, the Board of Directors subsequently suspended the quarterly dividend. No cash or share dividend was issued for the fourth quarter of 2015.

On November 9, 2015, the Company announced the sanctioning of the development of the MDA, MBH and MDK gas fields. The Company had secured the gas sales agreement ("GSA") for the first tranche of gas from the MDA-MBH fields development.

On December 3, 2015, the Company announced the signing of a production sharing contract ("PSC") for Block 15/33 in the Pearl River Mouth Basin in the South China Sea. Under the PSC, Husky has an obligation to drill two exploration wells within the first three years.

During 2015, the Company acquired 2-D and 3-D seismic survey data on the Anugerah contract area.

2016

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 was modified to a debt-to-capital covenant.

On March 31, 2016, the Company announced that holders of 1,564,068 Series 1 Preferred Shares exercised their option to convert their shares, on a one-for-one basis, to Series 2 Preferred Shares and receive a floating rate quarterly dividend.

On April 18, 2016, the Company announced that it had commenced production at the 10,000 bbls/day Edam East Thermal Project in Saskatchewan.

On April 19, 2016, the Company commenced production from the Colony formation at the Tucker Thermal Project in the Cold Lake region of Alberta.

On May 25, 2016, the Company completed the sale of Western Canada royalty interests to a third party for gross proceeds of $165 million.

On June 16, 2016, the Company announced that it had commenced production at the 10,000 bbls/day Vawn Thermal Project in Saskatchewan.

Production from the Sunrise Energy Project was temporarily impacted by wildfires in the Fort McMurray region of Alberta in the second quarter of 2016. Operations were successfully restarted in the same quarter with all 55 well pairs back online and the plant being fully operational.

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 include 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, Husky Midstream Limited Partnership ("HMLP"), of which Husky owns 35 percent, Power Assets Holdings Limited ("PAH")owns 48.75 percent and CK Infrastructure Holdings Limited ("CKI") owns 16.25 percent. Proceeds from the transaction were received in the third quarter of 2016.

On August 2, 2016, the Company announced that its China subsidiary had signed a Heads of Agreement ("HOA") with China National Offshore Oil Corporation ("CNOOC") and relevant companies for the price adjustment of natural gas from the Liwan 3-1 and Liuhua 34-2 fields with the revised price set at Cdn$12.50-Cdn$15.00 per mcf. The price adjustment under the HOA was effective as of November 20, 2015, and the settlement of outstanding payment was calculated from that date.

On August 29, 2016, the Company commenced production at the 4,500 bbls/day Edam West Thermal Project in Saskatchewan.

On September 15, 2016, the Company commenced production at the North Amethyst Hibernia formation well offshore NL.

On October 27, 2016, the Company announced that at the Liwan Gas Project, the second 22-inch subsea pipeline connecting the deepwater pipeline to the central platform was completed, tested and placed in service. This pipeline provides operating flexibility for the deepwater infrastructure and completes the Liwan facilities to their full design specification.

On November 9, 2016, the Canada-Newfoundland and Labrador Offshore Petroleum Board ("C-NLOPB") announced that the Company was the successful bidder on two parcels of land in its 2016 land sale. The lands cover an area of 211,574 hectares and brought the Company's exploration licences ("ELs") in the region to eight. The southwest parcel is adjacent to the White Rose field and satellite extensions, while the other is northeast of the field and adjacent to other Husky operated ELs in the Jeanne d'Arc Basin.

On November 29, 2016, the Company commenced production from a third well at the South White Rose project in the Jeanne d'Arc Basin offshore NL.

In late 2016, the Company sanctioned three new Lloyd thermal projects with total design capacity of 30,000 bbls/day at Dee Valley, Spruce Lake North and Spruce Lake Central.

Also during 2016, the Company completed the sale of approximately 30,200 boe/day of legacy crude oil and gas assets in Western Canada for gross proceeds of $1.12 billion.

2017

On March 10, 2017, the Company issued $750 million of 3.60 percent notes due March 10, 2027 by way of a prospectus supplement dated March 7, 2017, to the 2015 Canadian Shelf Prospectus. 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 April 13, 2017, the Company announced that it had signed a PSC for Block 16/25 in the Pearl River Mouth Basin in the South China Sea. Under the PSC, Husky has an obligation to drill two exploration wells within the first three years.

On May 5, 2017, the Company announced that, during the first quarter of 2017, it had commenced production from a new eight-well pad at the Tucker Thermal Project in the Cold Lake region of Alberta and from a new infill well at North Amethyst offshore NL.

On May 29, 2017, the Company announced that, together with its partners, it would be moving forward with the West White Rose Project in the Jeanne d'Arc Basin offshore NL, using a fixed wellhead platform tied back to the SeaRose FPSO, which would enable the Company and its partners to maximize resource recovery.

Also in May 2017, the Company announced a new discovery at Northwest White Rose. The White Rose A-78 well was drilled approximately 11 kilometres northwest of the SeaRose FPSO in the first quarter of 2017 and delineated a light oil column of more than 100 metres (gross). The Company has a 93.23 percent working interest in the well.

On July 21, 2017, the Company announced that the construction and installation of the shallow water jackets and subsea pipelines for the MDA-MBH fields in the Madura Strait were completed. The contract for a leased floating production unit was signed, and planning for the build commenced.

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.

On October 26, 2017, the Company announced that, during the third quarter of 2017, gas production from the BD Project commenced and was sold from the onshore gas distribution facility in East Java under a fixed price GSA.

Also in October 2017, the Company announced that the GSA for future gas production from Liuhua 29-1, the third deepwater gas field at the Liwan Gas Project, was signed. The project was sanctioned in the fourth quarter of 2017.

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 acquisition included the Superior Refinery's associated logistics, including two asphalt terminals, 3.6 mmbbls of crude and product storage and a fuels and asphalt marketing business. See "Description of Husky's Business – Downstream Operations – U.S. Refining and Marketing – Superior Refinery".

In November 2017, the Company sanctioned two new 10,000 bbls/day thermal projects at Westhazel and Edam Central.

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 ELs in the basin.

Also in November 2017, the Company's participation in the Wenchang oilfields petroleum contract expired, and the Company will not be entitled to any further production rights.

During 2017, the Company completed the sale of select assets in Western Canada, representing approximately 20,200 boe/day for gross proceeds of approximately $185 million.

Also during 2017, regulatory approval was received for the three Lloyd thermal projects sanctioned in late 2016, Dee Valley, Spruce Lake North and Spruce Lake Central.

Also during 2017, the Company and Imperial Oil closed their previously announced transaction to create a single expanded truck transport network of approximately 160 sites.

DESCRIPTION OF HUSKY'S BUSINESS

Overview

Husky is a publicly traded international integrated energy company headquartered in Calgary, Alberta, Canada.

Management has identified segments for the Company's business based on differences in products, services and management responsibility. The Company's business is conducted predominantly through two major business segments: Upstream and Downstream.

Upstream operations include exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids ("NGL") ("Exploration and Production") and marketing of the Company's and other producers' crude oil, natural gas, NGLs, 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 Alberta, Saskatchewan and British Columbia ("Western Canada"), offshore the east coast of Canada ("Atlantic") and offshore China and offshore Indonesia ("Asia Pacific").

Downstream operations 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 asphalt, gasoline, jet fuel and diesel fuels 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.

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 Atlantic and Asia Pacific ("Offshore").

The Company's business in the Integrated Corridor includes crude oil, bitumen, natural gas and NGL production from Western Canada, the Lloydminster upgrading and asphalt refining complex, the Prince George Refinery, HMLP (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.

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.

Upstream Operations

Integrated Corridor

Thermal and Non-Thermal Developments

Heavy Oil

The majority of the Company's heavy oil assets are located in the Lloydminister region of Alberta and Saskatchewan, with lands consisting of approximately two million acres. This extensive land position spans most of the productive oil fields in the area, all within 100 kilometres of the City of Lloydminister.The majority of the Company's operations are 100 percent working interest. The Company's operations are supported by a network of Company-owned treating facilities and operated pipelines that transport heavy crude oil from the field locations to the Husky Lloydminister Asphalt Refinery, the Husky Lloydminister Upgrader and third-party pipeline systems at Hardisty, Alberta, providing full integration with the Company's Upstream Infrastructure and Marketing and its Downstream business segments.

Production of heavy crude oil from the Lloydminister area uses a variety of technologies, including Cold Heavy Oil Production with Sand ("CHOPS"), horizontal wells, waterflooded fields and non-thermal enhanced oil recovery ("EOR").

The Company operated five carbon dioxide ("CO2") injection EOR pilot projects in 2017 and a CO2 capture and liquefaction plant at the Lloydminster Ethanol Plant. The liquefied CO2 is used in the ongoing EOR piloting program. The Company is also piloting several types of CO2 capture technology at its Lashburn facility in Saskatchewan.

Lloydminster Thermal Projects

Lloydminster bitumen production consists of nine thermal plants located in the Lloydminster region of Saskatchewan: Bolney/Celtic, Edam East, Edam West, Paradise Hill, Pikes Peak, Pikes Peak South, Rush Lake, Sandall and Vawn. Each plant has a number of production pads and utilizes Steam-Assisted Gravity Drainage ("SAGD") technology. 2017 production from Lloyd thermal projects averaged 77,100 bbls/day.

In 2017, work continued on the 10,000 bbls/day Rush Lake 2 thermal development, with the central facility 65 percent complete as of the end of 2017, and with first bitumen expected in the first quarter of 2019.

Regulatory approval has also been secured for the next three new Lloyd thermal projects at Dee Valley, Spruce Lake North and Spruce Lake Central with a total design capacity of about 30,000 bbls/day. 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 the next two 10,000 bbls/day thermal developments at Edam Central and Westhazel respectively. First production is expected in the second half of 2021.

All of the Company's six new sanctioned 10,000 bbls/day thermal developments represent long life assets, using repeatable modular designs, with low sustaining capital requirements.

Tucker Thermal Project

The Tucker Thermal Project is a SAGD oil sands project located 30 kilometres northwest of Cold Lake, Alberta. It commenced bitumen production at the end of 2006.

In 2017, bitumen production averaged 21,900 bbls/day, with daily peak rates exceeding 24,000 bbls/day. Production is expected to reach 30,000 bbls/day by the end of 2018 through further development and optimization.

Sunrise Energy Project

On March 31, 2008, Husky and BP Corporation North America Inc. ("BP") completed a transaction that created integrated North American oil sands and refining businesses. The businesses are comprised of a 50/50 partnership to develop the Sunrise Energy Project, operated by Husky, and a 50/50 limited liability company for the BP-Husky Toledo Refinery, operated by BP.

The Sunrise Energy Project is a SAGD oil sands project located in the Athabasca region of northern Alberta. At the end of 2017, there were 69 producing well pairs. In 2017, bitumen production averaged approximately 40,200 bbls/day (20,100 bbls/day Husky working interest). The project is expected to reach its 60,000 bbls/day nameplate capacity by the end of 2018.

Western Canada

Foothills Operations

The Company's Foothills operations are located primarily in western Alberta. Primary areas of operations consist of Rocky Mountain House, Edson and Grande Prairie. Foothills operations are centered on a gas resource growth strategy.

Within its Foothills operations, production in 2017 consisted of approximately 1,700 bbls/day of light and medium crude oil, 6,000 bbls/day of NGL and 252.5 mmcf/day of natural gas. The area is heavily weighted towards natural gas production at approximately 81 percent. The Company is pursuing liquids-rich natural gas development opportunities within the existing asset portfolio primarily in the Ansell and Kakwa areas.

The Kakwa Spirit River liquids-rich gas resource play, in which 2017 production averaged 3,500 boe/day, is located south of Grande Prairie. The Company initiated an operated drilling program with four wells drilled in the fourth quarter of 2017, and one well was put on production before the end of 2017. The remaining three wells are expected to come on production in the first quarter of 2018.

Edson operations are located primarily in northern Alberta and consist of the Ansell and Galloway areas. The Ansell liquids-rich natural gas resource play is located in the deep basin Cretaceous formations of west-central Alberta, with the Company holding an average 95 percent working interest in approximately 173 net sections of contiguous lands. The Company has been actively developing the Spirit River formations since 2012 using multi-stage fractured horizontal wells. Production from the Ansell and Galloway areas has doubled since 2012 and in 2017 averaged 2,100 bbls/day of NGL and 120 mmcf/day of natural gas. The Company operates over 400 producing wells at Ansell including 51 Spirit River horizontal wells and 20 Cardium horizontal wells. In 2017, the Company drilled 17 horizontal wells and completed 12 horizontal wells with nine wells on production at the end of 2017.

In the Wembley and Karr areas of Alberta, the Company has drilled five wells in the liquids-rich Montney formation. At Wembley, three wells have been drilled with one currently on production and two expected to be on production in 2018. At Karr, two wells were drilled and on production before the end of 2017.

Resource oil development is focused on the Cardium oil play in the Wapiti area south of the city of Grand Prairie, Alberta, utilizing horizontal well and multi-stage fracturing technology to unlock crude oil reserves. During 2017, production from the Cardium play averaged 2,500 boe/day. A four well drilling program was completed in the fourth quarter of 2017 with all four wells expected to be completed and put on production in the first quarter of 2018.

Plans in 2018 for Foothills include an 18-well development program targeting the Spirit River formation and an eight- well development program targeting the Montney formation.

Plains Operations

The Company's Plains operations are located in central Alberta, northern Alberta and southwest Saskatchewan. As at December 31, 2017, the Company operated one crude oil and four natural gas facilities with approximately 400 active wells throughout the area. Production in 2017 averaged 3,900 bbls/day of crude oil, 400 bbls/day of NGL and 28.5 mmcf/day of natural gas.

Rainbow Lake Development

Rainbow Lake, located approximately 900 kilometres northwest of Edmonton, Alberta, is the site of the Company's largest light oil production operation in Western Canada. Production during 2017 from the Rainbow Lake Development operations averaged 5,300 bbls/day of light crude oil, 4,100 bbls/day of NGL and 72.6 mmcf/day of natural gas. NGL and natural gas production ramped up in 2017 with the sale of additional volumes which are no longer required for injection into EOR operations, which was enabled by the completion and start-up of a 4,000 bbls/day NGL processing and truck loading facility in the second quarter of 2017.

The Company holds a 50 percent interest in a 90 megawatt natural gas fired cogeneration facility adjacent to its Rainbow Lake processing plant. The cogeneration facility produces electricity and thermal energy, or steam, for the Rainbow Lake processing plant. Additional electricity is also generated for the Power Pool of Alberta.

Northwest Territories

The Company holds two ELs acquired in 2011 in the Northwest Territories at the Slater River Canol shale play, which were consolidated as one EL in 2015 and cover 483,000 gross acres (466,000 net acres). Two vertical pilot wells were drilled, completed and flow tested in 2012. These wells satisfied the requirements to extend the term of both the ELs to the full nine-year term. The Company acquired a 220-square kilometre multi-component 3-D seismic survey in 2012, and construction of an all-season access road was completed in 2014. In 2016, the Company was awarded a significant discovery declaration on 545 sections (150,000 hectares) of land north of the Gambill Fault. Additionally, five sections of land were granted significant discovery licence ("SDL") status earlier in 2016 based on the MGM East MacKay I-78 well south of the Gambill Fault. The Company engaged in no activity in the Northwest Territories in 2017, and no activity is planned for 2018.

Offshore

Asia Pacific

China

Liwan Gas Project

The Liwan Gas Project includes the natural gas discoveries at the Liwan 3-1, Liuhua 34-2 and Liuhua 29-1 fields within the Contract Area 29/26 exploration block located in the Pearl River Mouth Basin of the South China Sea, approximately 300 kilometres southeast of the Hong Kong Special Administrative Region.

The Company has a 49 percent working interest in the project, and CNOOC has a 51 percent working interest. The initial development project of the Liwan 3-1 and Liuhua 34-2 fields was separated into deepwater and shallow water development projects, with the Company acting as deepwater operator and CNOOC acting as shallow water operator. The deepwater infrastructure includes production wells and trees, subsea pipelines and manifolds that produce to twin 22-inch deepwater pipelines running approximately 78 kilometres to a shallow water central platform. The shallow water infrastructure includes the central platform standing in approximately 120 metres of water, a 261-kilometre shallow water pipeline running from the central platform to the onshore Gaolan Gas Plant and the onshore gas plant with liquids separation facilities, 10 spherical NGL storage tanks, an export jetty, control facilities as well as administrative and accommodation buildings.

The Liwan 3-1 field commenced production at the end of March 2014. The gas field is currently producing from nine wells. The single production well in the Liuhua 34-2 field was tied into the deepwater facilities of the Liwan 3-1 field and commenced production in December 2014.

In 2017, gross gas sales from Liwan 3-1 and Liuhua 34-2 averaged 283 mmcf/day and 29 mmcf/day, respectively. In 2017, the Company's working interest share of production from the two fields was 153 mmcf/day of conventional natural gas and 6,900 bbls/day of NGL.

The Liuhua 29-1 field is planned to be developed in a second project phase. The Company, acting as deepwater operator, plans to complete production wells and lay deepwater pipelines to tie into the existing Liuhua 34-2 field production manifold to share the existing Liwan Gas Project subsea infrastructure and the onshore Gaolan Gas Plant. In 2017, a gas sales agreement ("GSA") was reached for future gas production from the field and the Board sanctioned the Liuhua 29-1 project for development. Construction is anticipated to begin in 2018, followed by first production in 2021.

Wenchang

The Wenchang field is located in the western Pearl River Mouth Basin, approximately 400 kilometres south of the Hong Kong Special Administrative Region and 100 kilometres east of Hainan Island. The Company held a 40 percent working interest in two oil fields, which commenced production in July 2002. The Wenchang 13-1 and 13-2 oil fields produced from 32 wells in 100 metres of water into an FPSO stationed between fixed platforms located in each of the two fields. In 2016, the PSC was extended for 130 days corresponding to the duration of production suspension for FPSO maintenance experienced in 2014. The PSC expired in November 2017, and the Company will not be entitled to any further production rights. The Company's share of production averaged 5,400 bbls/day of light crude oil and NGL during 2017.

Block 15/33

The Company executed a PSC in December 2015 for an exploration block offshore China. Block 15/33 is located in the Pearl River Mouth Basin in the South China Sea, about 140 kilometres southeast of the Hong Kong Special Administrative Region and covers an area of 155 square kilometres in water depths of approximately 80 100 metres. The Company is the operator of the block during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, its partner CNOOC may assume a working interest of up to 51 percent during the development and production phase. Under the PSC, the corresponding CNOOC share of exploration costs is to be recovered from production allocated to the Company. The Company expects to drill two exploration wells in the 2018 timeframe.

Block 16/25

The Company executed a PSC in April 2017 for an exploration block offshore China. Block 16/25 is located in the Pearl River Mouth Basin in the South China Sea, about 150 kilometres southeast of the Hong Kong Special Administrative Region and approximately 72 kilometres northeast of Block 15/33. The block covers an area of 44 square kilometres in water depths of approximately 85 100 metres. The Company is the operator of the block during the exploration phase, with a working interest of 100 percent. In the event of a commercial discovery, its partner CNOOC may assume a working interest of up to 51 percent during the development and production phase. Under the PSC, the corresponding CNOOC share of exploration costs is to be recovered from production allocated to the Company. The Company expects to drill two exploration wells in the 2018 timeframe in conjunction with the drilling on Block 15/33.

Taiwan

In December 2012, the Company signed a joint venture agreement with CPC Corporation. The Company and CPC Corporation have rights to an exploration block in the South China Sea covering approximately 7,700 square kilometres located southwest of the island of Taiwan. The Company holds a 75 percent working interest during exploration, while CPC Corporation has the right to participate in the development program up to a 50 percent interest.

The acquisition of 2-D seismic survey data was completed in 2014, and the acquisition of 3-D seismic survey data was completed in 2017. The Company is analyzing the 3-D seismic survey data to identify potential drilling prospects.

Indonesia

Madura Strait

The Company has a 40 percent interest in approximately 622,000 acres (2,516 square kilometres) of the Madura Strait, located offshore East Java, in Indonesia. The Company's two partners are CNOOC, which is the operator and has a 40 percent working interest, and Samudra Energy Ltd., which holds the remaining 20 percent interest through its affiliate, SMS Development Ltd. The Madura Strait includes the operating BD field and developments at the MDA, MBH, MDK and MAC fields and three additional discoveries.

In 2017 at the liquids-rich BD field, testing and commissioning of the shallow water production platform, FPSO, subsea pipeline to shore and onshore gas metering station were completed and first sales production was achieved mid-year. Gas sales to a second customer commenced in December. Gross gas sales are expected to ramp up to the full sales production target of 100 mmcf/day of gas and 6,000 bbls/day of associated liquids in 2018. Gross BD field sales averaged 20 mmcf/day of gas and 1,600 bbls/day of associated liquids in 2017. The Company's working interest share of production was 8 mmcf/day and and 600 bbls/day, respectively.

At the MDA and MBH fields, facilities construction is ongoing. The platforms and in-field and tie-in production pipelines have been installed. A contract for the lease of a floating production unit vessel was signed in July 2017. Drilling of five MDA field production wells and two MBH field production wells is planned for the first half of 2018. Production from the MDA, MBH and MDK fields is expected in the 2019 timeframe with the additional MDK shallow water field expected to be tied in during the same period. Combined working interest sales volumes from the BD, MDA, MBH and MDK fields are expected to be approximately 100 mmcf/day of natural gas and 2,400 bbls/day of associated NGL once production is fully ramped up. 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

The Company executed a PSC in February 2014 with the Government of Indonesia for the Anugerah contract area. The Company holds a 100 percent interest in the Anugerah Block, which is located in the East Java Basin approximately 150 kilometres east of the Madura Strait. The block covers an area of 2,030,000 acres (8,215 square kilometres) with potential drilling opportunities in water depths of 800 to 1,300 metres. The PSC requires the acquisition of 2-D and 3-D seismic data during the first three years of the contract. In 2015 and 2016, a seismic acquisition program was carried out, and the results from the seismic surveys' data continue to be evaluated to determine the potential for future drilling opportunities.

Atlantic

Overview

The Company's Atlantic exploration and development program is focused in the Jeanne d'Arc Basin and the Flemish Pass. The Jeanne d'Arc Basin contains the Hibernia, Terra Nova and Hebron fields, as well as the White Rose field and satellite extensions, including North Amethyst, West White Rose and South White Rose. In the Flemish Pass Basin, the Company holds a 35 percent non-operated working interest in each of the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries. The Company is the operator of the White Rose field and satellite extensions and holds an ownership interest in the Terra Nova field, as well as a number of smaller undeveloped fields. The Company also holds significant exploration acreage offshore NL.

White Rose Field and Satellite Extensions

The White Rose field is located 354 kilometres off the coast of NL and is approximately 48 kilometres east of the Hibernia field on the eastern flank of the Jeanne d'Arc Basin. The Company is the operator of the main White Rose field and satellite tiebacks, including the North Amethyst, West White Rose and South White Rose extensions. The Company has a 72.5 percent working interest in the main field and a 68.875 percent working interest in the satellite extensions. To date, production has been facilitated via subsea tie-ins with wells drilled independently through drill centres and connected via flowlines to the SeaRose FPSO.

First oil was achieved at White Rose in November 2005. The White Rose field currently has 10 production wells, 10 water injection wells and three gas injection wells. During 2017, the Company's light crude oil production from the White Rose field was 11,000 bbls/day (Husky working interest).

On May 31, 2010, first oil was achieved from North Amethyst, the first satellite extension at the White Rose field. The field is located approximately six kilometres southwest of the SeaRose FPSO. Production flows from North Amethyst to the SeaRose FPSO through a series of subsea flow lines. In September 2016, the Company began production from the deeper Hibernia formation at North Amethyst utilizing existing infrastructure. As of December 31, 2017, the field had seven production wells and four water injection wells. During 2017, the Company's light crude oil production from North Amethyst was 10,000 bbls/day (Husky working interest).

Initial production from West White Rose was achieved in September 2011 through a two-well pilot project. The pilot wells have helped provide further information on the reservoir to refine development plans for the full West White Rose field. During 2017, the Company's share of light crude oil production from this satellite field was 2,000 bbls/day (Husky working interest).

In May 2017, the Company and its co-venturers announced plans to proceed with full field development at West White Rose using a fixed drilling platform. First oil is forecasted for 2022, with the West White Rose Project expected to ramp up to peak production of 52,500 bbls/day (Husky working interest) in 2025 as development wells are brought online. Costs are estimated at $2.2 billion (Husky working interest) to first oil. Like the other White Rose tiebacks, the platform will leverage existing offshore infrastructure including the SeaRose FPSO.

Production commenced from the South White Rose Extension in 2015 with production wells supported by both gas flood and water injection. The South White Rose Extension was developed in phases, with gas injection equipment installed in 2013 and oil production equipment installed in 2014. As at December 31, 2017, the project had four production wells, one water injection well and one gas injection well. During 2017, the Company's working interest share of light crude oil production from the South White Rose Extension was 7,000 bbls/day.

Terra Nova Field

The Terra Nova field is located approximately 350 kilometres southeast of St. John's, NL. The Terra Nova field is divided into three distinct areas, known as the Graben, the East Flank and the Far East. Production at Terra Nova commenced in January 2002. The Company's working interest in the field increased to 13 percent effective December 1, 2010.

As at December 31, 2017, there were 14 development wells drilled in the Graben area, consisting of eight production wells, four water injection wells and two gas injection wells. In the East Flank area, there were 14 development wells, consisting of eight production wells and six water injection wells. The Far East has one extended reach producer and an extended reach water injection well. The operator continues to progress delineation and development opportunities at Terra Nova.

Light crude oil production during 2017 from the Terra Nova field was 4,000 bbls/day (Husky working interest).

East Coast Exploration

The Company holds working interests ranging from 5.8 percent to 100 percent in 24 Significant Discovery Areas in the Jeanne d'Arc Basin and Flemish Pass Basin, offshore NL and Baffin Island.

In May 2017, the Company announced a near-field oil discovery at Northwest White Rose. The White Rose A-78 well was drilled approximately 11 kilometres northwest of the SeaRose FPSO in the first quarter of 2017 and delineated a light oil column of more than 100 metres. The discovery continues to be assessed. Husky has a 93.232 percent ownership interest. A potential development could leverage the SeaRose FPSO, existing subsea infrastructure and the future West White Rose wellhead platform.

In June 2016, the Company and its partner announced two oil discoveries at the Bay de Verde and Baccalieu prospects in the Flemish Pass Basin, which add to the resource base for a potential development at the Bay du Nord discovery.The Company holds a 35 percent non-operated working interest in each of the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries. The C-NLOPB issued an SDL for Bay du Nord in November 2017. The SDL 1055 covers an area of 13,149 hectares. The Company and its partner continue to assess the commercial potential of these discoveries.

In November 2017, the C-NLOPB announced that the Company was the successful bidder on a parcel of land in its 2017 land sale. The lands cover an area of 121,453 hectares in the Jeanne d'Arc Basin. The lands are adjacent to other Husky ELs in the basin, and bring the Company's ELs in the region to nine.

Infrastructure and Marketing

Overview

The Company is engaged in the marketing of both its own and other producers' crude oil, natural gas, NGL, sulphur and petroleum coke production. The Infrastructure and Marketing business manages the sale and transportation of the Company's Upstream and Downstream production and third-party commodity trading volumes through access to capacity on third-party pipelines and storage facilities in both Canada and the U.S. The Company is able to capture differences between the two markets by utilizing infrastructure capacity to deliver feedstock acquired in Canada to the U.S. market.

Husky Midstream Limited Partnership

HMLP was created in July 2016 with the sale of selected pipeline gathering systems in Alberta and Saskatchewan and the Lloydminster and Hardisty terminals. CKI owns 16.25 percent, PAH owns 48.75 percent, and Husky owns 35 percent of HMLP and remains the operator. The entity has 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 Lloydminster Terminal, with a total storage capacity of 1.0 mmbbls, serves as a hub for the gathering systems. The pipeline systems transport blended heavy crude oil to Lloydminster,accessing markets through Husky's Upgrader and Asphalt Refinery in Lloydminster. Blended heavy crude oil and bitumen from the field and synthetic crude oil from the upgrading operations are transported south to Hardisty, Alberta to a connection with the major export trunk pipelines. The Hardisty Terminal, with a total storage capacity of 3.1 mmbbls, acts as the exclusive blending hub for Western Canada Select ("WCS"), the largest heavy oil benchmark pricing point in North America.

HMLP has a separate Board of Directors from Husky and independent financing that supports both significant growth projects that are under construction and forecasted future expansions. Approximately $800 million in growth projects are underway. 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.

In 2018, HMLP expects to commission a 150-kilometre pipeline system in Alberta to allow for third-party and Husky production growth in both Alberta and Saskatchewan. A second major pipeline project is underway in Saskatchewan to provide transportation for the anticipated increase in the Company's bitumen production. The Hardisty terminal is also expanding to provide additional pipeline connectivity and crude oil storage for customers. The assets will play an integral and valuable role in the successful transportation of heavy oil and bitumen production to end markets by providing connections to the Husky Lloydminster Upgrader and Asphalt Refinery, third-party terminals and pipelines through strategic hubs such as the Hardisty Terminal.

Third-Party Pipeline Commitments

In 2010, the Company commenced its pipeline commitment on the Keystone pipeline system, which ships Canadian crude oil from Hardisty, Alberta to Patoka, Illinois. This commitment was part of a strategy, commenced in 2006, to expand the market for the Company's crude oil into the midwest U.S. This strategy was further supported through the acquisition of the Lima Refinery in 2007, which now enables the Company's Canadian synthetic and bitumen production along with additional third-party purchases to be processed at the refinery. The Company has the ability to utilize the portion of the Keystone pipeline system that continues to Cushing, Oklahoma, and the Company holds long-term firm capacity on the Enbridge Flanagan South pipeline and Southern Access Extension pipeline which connect Enbridge's Mainline to the U.S. Gulf Coast and Patoka markets.

Due to the Company's ongoing Keystone pipeline commitment, the Lima Refinery has the option to access a significant amount of Canadian crude oil as part of its crude feedstock requirements. The Keystone pipeline has enabled the Company to sell bitumen through interconnecting pipeline systems to the Lima Refinery and into Cushing, Oklahoma.

Since 2012, the pipeline systems leaving Canada have at times been subject to significant apportionment, affecting both Canadian export volumes and crude oil prices in Western Canada. The Company has mitigated these effects through the reliability of its proprietary pipeline system, its firm capacity on export pipelines and the Company's demand for Canadian crude oil feedstock for its Canadian upgrading and refining assets. In 2017, the Company further enhanced this integration when it purchased a 50,000 bbls/ day refinery at Superior, Wisconsin which runs a combination of heavy Canadian crude and light crudes from Canada and the U.S. The Superior Refinery is located on the Enbridge Mainline crude system. As a seller and buyer of crude oils, the Company has a relatively balanced exposure to many location and grade differentials.

The Company has been monitoring opportunities to participate in growing crude oil markets accessed by rail, which have developed due to refiners' desire for inland crude oil which has at times been priced at significant discounts to ocean imports. The Company has made crude oil deliveries to rail-loading facilities via trucks, where netbacks can be increased relative to pipeline alternatives. While the Company's primary focus is on low-cost pipeline transportation options, it has developed the capability to employ rail transport to a variety of crude oil markets.

Natural Gas Storage Facilities

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

Commodity Marketing

The Company is a marketer of both its own and third-party production of crude oil, synthetic crude oil, NGL, natural gas and sulphur. The Company also markets petroleum coke, a by-product from the Lloydminster Upgrader and its Ohio and Wisconsin refineries. The Company supplies feedstock to its Lloydminster Upgrader and Asphalt Refinery from its own and third-party heavy oil and bitumen production sourced from the Lloydminster and Cold Lake areas. The Company also sells blended heavy crude oil directly to refiners based in the U.S. and Canada. The extensive infrastructure in the Lloydminster area supports the Company's heavy crude oil refining and marketing operations. The Company markets light and medium crude oil and NGL sourced from its own production and third-party production. Light crude oil is acquired for processing by the Prince George Refinery, the Lima Refinery and the Superior Refinery. The Company markets the synthetic crude oil produced at its Upgrader in Lloydminster to refiners in Canada and the U.S., including the Lima Refinery and other refineries in the midwest U.S.

The Company markets natural gas sourced from its own production and third-party production. The Company is currently committed to gas sales contracts with third parties, which in aggregate do not exceed amounts forecasted to be deliverable from the Company's reserves. The natural gas sales contracts are primarily at market prices other than those that meet the Company's own use requirements. The Company trades natural gas to generate revenue from managed assets, including transportation and natural gas storage facilities.

The Company has developed its commodity marketing operations to include the acquisition of third-party volumes to enhance the value of its midstream assets.

Downstream Operations

Upgrading Operations

The Company owns and operates the Husky Lloydminster Upgrader, a heavy oil upgrading facility located in Lloydminster, Saskatchewan. The Upgrader 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 Upgrader recovers the 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 was commissioned in 1992 with an original design capacity of 46 mbbls/day of synthetic crude oil. Current production is considerably higher than the original design rate capacity as a result of throughput modifications and improved reliability. In 2007, the Upgrader commenced production of transportation grade diesel. The Upgrader's current rated production capacity is 82,000 bbls/day of synthetic crude oil, diluent and ultra low sulphur diesel.

Production at the Upgrader averaged 49,000 bbls/day of synthetic crude oil, 14,000 bbls/day of diluent and 6,000 bbls/day of ultra low sulphur diesel in 2017. In addition, as by-products of its upgrading operations, the Upgrader produced approximately 316 long tons/day of sulphur and 916 long tons/day of petroleum coke during 2017. These products are sold in Canadian and international markets.

Canadian Refined Products

The Company's Canadian Refined Products operations include refining of light crude oil, manufacturing of fuel and fuel grade ethanol, manufacturing of asphalt products from heavy crude oil and bitumen and acquisition by purchase and exchange of refined petroleum products. The Company's retail distribution network includes the wholesale, commercial and retail marketing of refined petroleum products and provides a platform for non-fuel related convenience product businesses.

Light oil refined products are produced at the Prince George Refinery and are also acquired from third-party refiners and marketed through the Company's retail and commercial petroleum outlets and through direct marketing to third-party dealers and end users. Asphalt and residual products are produced at the Company's Asphalt Refinery at Lloydminster, Alberta and are marketed directly or through the Company's eight emulsion plants, five of which are also asphalt terminals located throughout western Canada.

Prince George Refinery

The Prince George Refinery provides refined products to the Company and third-party retail outlets in the central and northern regions of British Columbia. Feedstock is delivered to the refinery by pipeline from northeastern British Columbia.

The Prince George Refinery produces all grades of unleaded gasoline, seasonal diesel fuels, mixed propane and butane and heavy fuel oil. During 2017, throughput averaged 11,200 bbls/day.

Lloydminster Asphalt Refinery

Husky's Asphalt Refinery in Lloydminster, Alberta, processes heavy crude oil and bitumen into asphalt products used in road construction and maintenance, and industrial asphalt products. The refinery has a throughput capacity of 29,000 bbls/day of heavy crude oil and bitumen. The refinery also produces straight run gasoline, bulk distillates and residuals. The straight run gasoline stream is removed and re-circulated into HMLP's pipeline network as pipeline diluent. The distillate stream is transferred to the Upgrader and furthered processed to make ultra low sulphur diesel fuel or treated for blending into the Husky Synthetic Blend ("HSB") stream. Residuals are a blend of medium and light distillate and gas oil streams, which are typically sold directly to customers as refinery feedstock, drilling and well-fracturing fluids, or used in asphalt cutbacks and emulsions.

Refinery throughput averaged 26,800 bbls/day of blended heavy crude oil and bitumen feedstock during 2017. In 2017, daily sales volumes of asphalt averaged 14,800 bbls/day and daily sales volumes of residual and other products averaged 11,900 bbls/day. Due to the seasonal demand for asphalt products, many asphalt refineries typically operate at full capacity only during the normal paving season in Canada and the northern U.S. The Company has implemented various strategies to increase refinery throughput during the other months of the year that are outside of the normal paving season, such as increasing storage capacity and developing U.S. markets for asphalt products. This allows the Lloydminster Asphalt Refinery to run at or near full capacity throughout the year.

Asphalt Distribution Network

In addition to sales directly from the Lloydminster Asphalt Refinery, the Company, through the Pounder Emulsions division, has an asphalt distribution network which consists of five asphalt terminals located at Kamloops, British Columbia, Edmonton and Lethbridge, Alberta, Yorkton, Saskatchewan and Winnipeg, Manitoba and two emulsion plants located at Lloydminster and Saskatoon, Saskatchewan. The Company also terminals asphalt at the Prince George Refinery and uses independently operated terminals in British Columbia, Alberta and the state of Washington.

The Company's wholesale sales to the U.S. and eastern Canada accounted for over 50 percent of its total asphalt sales in 2017. Exported asphalt products are shipped across the U.S. and Canada. The Company sold 5.1 mmbbls of asphalt in 2017.

In 2018, the Company plans to increase asphalt modification capacity, expand sales in U.S. markets and further market residual products as refinery feedstock.

Ethanol Plants

In September 2006, the Company commissioned an ethanol plant in Lloydminster, Saskatchewan. The plant has an annual nameplate capacity of 130 million litres. In December 2007, the Minnedosa, Manitoba ethanol plant was commissioned also with an annual nameplate capacity of 130 million litres and is currently operating above that capacity due to efforts to optimize yield. In 2017, ethanol production averaged 804.8 thousand litres/day.

The Company's ethanol production supports its ethanol-blended gasoline marketing program. When added to gasoline, ethanol promotes more complete fuel combustion, prevents fuel line freezing and reduces carbon monoxide emissions, ozone precursors and net emissions of greenhouse gases ("GHG"). Environment Canada has designated ethanol blended gasoline as an "Environmental Choice" product. The Company sells a large portion of its production to other major oil companies for their ethanol blending requirements in western Canada.

During 2012, the Lloydminster plant commissioned a CO2 capture facility. The plant is currently capturing CO2 for use in the Company's non-thermal EOR projects.

Branded Petroleum Product Outlets and Commercial Distribution

During 2015, the Company and Imperial Oil entered into a contractual agreement to create a single expanded truck transport cardlock network of approximately 160 sites. The agreement has been fully implemented, and the consolidation of the two cardlock networks, under the Esso brand, was completed in the third quarter of 2017.

As at December 31, 2017, there were 558 independently operated Husky and Esso-branded petroleum product outlets. These outlets include travel centres, convenience stores, cardlock and bulk distribution facilities located from coast to coast. The Company's network of travel centres feature a proprietary cardlock system that enables commercial customers to purchase products using a sophisticated card system that processes transactions, provides detailed billing, fuel and sales tax information and offers advanced fraud protection. A variety of full and self-serve retail locations serve urban and rural markets across the network, while the Company's bulk distributors offer direct sales to commercial and agricultural markets in the Prairie provinces.

The Company's retail and commercial operating model is balanced by corporate-owned/dealer-operated and branded dealer owned and operated sites. Retail outlets offer a variety of services, including convenience stores, service bays, 24-hour accessibility, car washes, Husky House restaurants and proprietary and co-branded quick-serve restaurants. In addition to ethanol-blended gasoline, the Company offers diesel, propane and Mobil-branded lubricants to customers. The Company supplies refined petroleum products to its branded independent retailers on an exclusive basis and provides financial and other assistance for location improvements, marketing support and related services.

The following table shows the number of Husky and Esso-branded petroleum outlets by province as of December 31, 2017:

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	**2017 Total**	2016 Total
Husky-Branded Petroleum Outlets									
Retail Owned Outlets	39	46	8	12	58	—	—	163	213
Leased	32	32	3	7	25	—	—	99	111
Independent Retailers	48	65	11	3	13	—	—	140	156
Total	**119**	**143**	**22**	**22**	**96**	**—**	**—**	**402**	480
Esso-Branded Petroleum Outlets									
Retail Owned Outlets	14	15	4	3	12	—	—	48	—
Leased	2	2	—	3	1	—	—	8	—
Independent Retailers	32	23	4	6	27	7	1	100	—
Total	**48**	**40**	**8**	**12**	**40**	**7**	**1**	**156**	—
Cardlocks(1)	**52**	**46**	**10**	**11**	**40**	**7**	**1**	**167**	84
Convenience Stores(1)	**80**	**86**	**14**	**21**	**95**	**—**	**—**	**296**	301
Restaurants	**8**	**9**	**3**	**1**	**13**	**—**	**—**	**34**	36

(1) Located at branded petroleum outlets.

The Company also markets refined petroleum products directly to various commercial markets, including independent dealers, national rail companies and major industrial and commercial customers in Canada and the northwestern U.S.

The following table shows average daily sales volumes of light refined petroleum products for the periods indicated:

	Years ended December 31,		
Average Daily Sales Volume *(mbbls/day)*	**2017**	2016	2015
Gasoline	**22.8**	22.4	23.1
Diesel fuel	**23.7**	18.5	23.7
Liquefied Petroleum Gas	**0.2**	0.2	0.2
	46.7	41.1	47.0

U.S. Refining and Marketing

Lima Refinery

The Lima Refinery, has an atmospheric crude throughput capacity of 165,000 bbls/day and an operating capacity of 140,000 to 165,000 bbls/day on its current crude slate. The Lima Refinery currently processes both light sweet crude oil and a small percentage of heavy crude oil feedstock sourced from the U.S. and Canada, which includes Canadian synthetic crudes, including HSB produced by the Lloydminster Upgrader. The Lima Refinery produces low sulphur gasoline, gasoline blend stocks, ultra-low sulphur diesel, jet fuel, petrochemical feedstock and other by-products. The feedstocks are received via the Mid-Valley and Marathon Pipelines, and the refined products are transported via the Buckeye, Inland, Sunoco Logistics and Teppco pipeline systems and by rail car to primary markets in Ohio, Illinois, Indiana, Pennsylvania and southern Michigan.

During 2017, total throughput at the Lima Refinery averaged 172,200 bbls/day. Production in 2017 consisted of gasoline averaging 86,000 bbls/day, total distillates averaging 69,000 bbls/day and total other products averaging 20,000 bbls/day.

The Lima Refinery continues to progress reliability and profitability improvement projects. Front End Engineering Design (“FEED”) commenced in the second half of 2013 to revamp existing refinery process units and add new equipment to allow the refinery to process up to 40,000 bbls/day of Western Canadian heavy crude oil while maintaining the existing capability and flexibility to refine light crude oil. Current heavy crude oil feedstock capability is 10,000 bbls/day.The full scope of the project is expected to be completed in phases over a two-year period through 2018 and 2019.

BP-Husky Toledo Refinery

The BP-Husky Toledo Refinery has a nameplate capacity of 160,000 bbls/day and an operating capacity of 140,000 to153,000 bbls/ day on its current crude slate. Products include low sulphur gasoline, ultra-low sulphur diesel, aviation fuels, propane and asphalt. The BP-Husky Toledo Refinery is located in one of the highest energy consumption regions in the U.S.

A feedstock optimization project completed during the 2016 turnaround was designed to improve the BP-Husky Toledo Refinery's ability to process high-TAN crude. In 2017, the benefits of this project were realized and the refinery processed 55,000 to 70,000 bbls/day of high-TAN crude, which supports the strategic intent for the refinery to process bitumen from the Sunrise Energy Project. Since January 1, 2017, the Company has been marketing its share of the joint operation's refined product.

During 2017, the Company's share of total throughput averaged 76,600 bbls/day, with the Company's share of production of gasoline averaging 45,200 bbls/day, distillates averaging 22,300 bbls/day and other fuel and feedstock averaging 10,100 bbls/day.

Superior Refinery

On November 8, 2017, the Company completed the acquisition of the Superior Refinery. The Superior Refinery has a permitted throughput capacity of 50,000 bbls/day and an operating capacity of 45,000 bbls/day on its current crude slate. Products include gasoline, diesel, asphalt and heavy fuel oils.

During 2017, annualized total throughput at the refinery averaged 5,500 bbls/day.

Disclosure of Oil and Gas Activities

Operating Netback Analysis[(1)]

The following tables show the Company's netback analysis by product and area:

	Year Ended	Three Months Ended			
Average Per Unit Amounts	**Dec 31, 2017**	Dec 31, 2017	Sept 30, 2017	June 30, 2017	Mar 31, 2017
Company Total[(2)]					
Sales volume *(mboe/day)*	**322.9**	320.4	317.7	319.5	334.0
Gross Revenue *($/boe)*[(3)]	**$ 42.47**	$ 46.69	$ 40.05	$ 41.58	$ 41.58
Royalties *($/boe)*	**$ 3.07**	$ 3.28	$ 2.45	$ 3.14	$ 3.47
Production and Operating Costs *($/boe)*[(3)]	**$ 13.93**	$ 13.20	$ 14.12	$ 14.65	$ 13.75
Transportation Costs *($/boe)*[(4)]	**$ 0.22**	$ 0.21	$ 0.23	$ 0.26	$ 0.19
Operating netback *($/boe)*	**$ 25.25**	$ 30.00	$ 23.25	$ 23.53	$ 24.17
Light and Medium Crude Oil *($/bbl)*					
Canada - Western Canada					
Gross Revenue[(3)]	**$ 53.11**	$ 58.96	$ 47.92	$ 51.17	$ 54.56
Royalties	**$ 6.17**	$ 7.14	$ 5.37	$ 6.34	$ 5.93
Production and Operating Costs[(3)]	**$ 30.29**	$ 34.44	$ 33.43	$ 30.35	$ 24.88
Operating netback	**$ 16.65**	$ 17.38	$ 9.12	$ 14.48	$ 23.75
Canada - Atlantic Canada					
Gross Revenue	**$ 71.69**	$ 82.12	$ 67.82	$ 66.36	$ 70.53
Royalties	**$ 6.75**	$ 5.71	$ 4.09	$ 6.27	$ 9.86
Production and Operating Costs	**$ 17.12**	$ 15.36	$ 24.98	$ 15.82	$ 14.64
Transportation Costs[(4)]	**$ 2.13**	$ 2.05	$ 2.89	$ 2.19	$ 1.64
Operating netback	**$ 45.69**	$ 59.00	$ 35.86	$ 42.08	$ 44.39
Canada - Total					
Gross Revenue[(3)]	**$ 66.82**	$ 76.33	$ 61.85	$ 62.75	$ 66.25
Royalties	**$ 6.60**	$ 6.07	$ 4.49	$ 6.29	$ 8.81
Production and Operating Costs[(3)]	**$ 20.57**	$ 20.13	$ 27.51	$ 19.27	$ 17.39
Transportation Costs[(4)]	**$ 1.57**	$ 1.54	$ 2.02	$ 1.67	$ 1.20
Operating netback	**$ 38.08**	$ 48.59	$ 27.83	$ 35.52	$ 38.85
China					
Gross Revenue	**$ 72.08**	$ 89.37	$ 71.09	$ 67.44	$ 70.45
Royalties	**$ 5.08**	$ 6.44	$ 5.06	$ 4.80	$ 4.79
Production and Operating Costs	**$ 11.96**	$ 24.16	$ 10.96	$ 12.96	$ 7.05
Operating netback	**$ 55.04**	$ 58.77	$ 55.07	$ 49.68	$ 58.61
Total					
Gross Revenue[(3)]	**$ 67.36**	$ 77.05	$ 63.13	$ 63.27	$ 66.70
Royalties	**$ 6.44**	$ 6.08	$ 4.56	$ 6.13	$ 8.37
Production and Operating Costs[(3)]	**$ 19.68**	$ 20.36	$ 25.21	$ 18.57	$ 16.27
Transportation Costs[(4)]	**$ 1.41**	$ 1.45	$ 1.74	$ 1.48	$ 1.07
Operating netback	**$ 39.83**	$ 49.16	$ 31.62	$ 37.09	$ 40.99
Heavy Crude Oil *($/bbl)*					
Canada - Total					
Gross Revenue[(3)]	**$ 43.38**	$ 48.64	$ 41.89	$ 42.06	$ 41.28
Royalties	**$ 4.43**	$ 5.44	$ 4.27	$ 4.37	$ 3.71
Production and Operating Costs[(3)]	**$ 23.62**	$ 22.46	$ 24.31	$ 24.58	$ 23.17
Operating netback	**$ 15.33**	$ 20.74	$ 13.31	$ 13.11	$ 14.40

Average Per Unit Amounts	Year Ended Dec 31, 2017	Three Months Ended Dec 31, 2017	Sept 30, 2017	June 30, 2017	Mar 31, 2017
Bitumen *($/bbl)*					
Canada - Total					
Gross Revenue[3][4]	**$ 38.20**	$ 41.88	$ 38.14	$ 37.46	$ 35.20
Royalties	**$ 2.08**	$ 1.81	$ 1.99	$ 2.43	$ 2.10
Production and Operating Costs[3]	**$ 11.27**	$ 9.83	$ 10.54	$ 12.94	$ 11.83
Operating netback	**$ 24.85**	$ 30.24	$ 25.61	$ 22.09	$ 21.27
Conventional Natural Gas *($/mcf)*					
Canada - Total					
Gross Revenue[3][5]	**$ 2.29**	$ 1.83	$ 1.64	$ 2.88	$ 2.79
Royalties[5][6]	**($ 0.11)**	($ 0.10)	($ 0.31)	($ 0.08)	($ 0.01)
Production and Operating Costs[3]	**$ 2.04**	$ 2.19	$ 2.02	$ 1.99	$ 1.96
Operating netback	**$ 0.36**	($ 0.26)	($ 0.07)	$ 0.97	$ 0.84
China					
Gross Revenue	**$ 13.29**	$ 13.40	$ 13.05	$ 13.44	$ 13.31
Royalties	**$ 0.74**	$ 0.82	$ 0.70	$ 0.71	$ 0.71
Production and Operating Costs	**$ 0.86**	$ 0.79	$ 0.72	$ 1.06	$ 0.95
Operating netback	**$ 11.69**	$ 11.79	$ 11.63	$ 11.67	$ 11.65
Indonesia[7]					
Gross Revenue	**$ 9.51**	$ 9.62	$ 9.39	$ —	$ —
Royalties	**$ 1.03**	$ 1.04	$ 1.02	$ —	$ —
Production and Operating Costs	**$ 2.10**	$ 1.90	$ 2.51	$ —	$ —
Operating netback	**$ 6.38**	$ 6.68	$ 5.86	$ —	$ —
Total					
Gross Revenue[3]	**$ 5.52**	$ 5.89	$ 5.25	$ 5.59	$ 5.35
Royalties	**$ 0.15**	$ 0.24	$ 0.05	$ 0.14	$ 0.17
Production and Operating Costs[3]	**$ 1.70**	$ 1.72	$ 1.64	$ 1.75	$ 1.71
Operating netback	**$ 3.67**	$ 3.93	$ 3.56	$ 3.70	$ 3.47
Natural Gas Liquids *($/bbl)*					
Canada - Total					
Gross Revenue[3]	**$ 32.08**	$ 35.22	$ 26.58	$ 27.76	$ 41.28
Royalties	**$ 10.16**	$ 11.04	$ 9.09	$ 8.76	$ 12.35
Production and Operating Costs[3]	**$ 12.13**	$ 13.07	$ 11.85	$ 11.86	$ 11.81
Operating netback	**$ 9.79**	$ 11.11	$ 5.64	$ 7.14	$ 17.12
China					
Gross Revenue	**$ 59.50**	$ 67.83	$ 54.39	$ 55.21	$ 60.33
Royalties	**$ 3.38**	$ 3.82	$ 3.08	$ 3.11	$ 3.48
Production and Operating Costs	**$ 5.31**	$ 4.92	$ 4.46	$ 6.48	$ 5.75
Operating netback	**$ 50.81**	$ 59.09	$ 46.85	$ 45.62	$ 51.10
Indonesia[7]					
Gross Revenue	**$ 77.79**	$ 77.79	$ —	$ —	$ —
Royalties	**$ 12.32**	$ 12.32	$ —	$ —	$ —
Production and Operating Costs	**$ 12.59**	$ 11.39	$ —	$ —	$ —
Operating netback	**$ 52.88**	$ 54.08	$ —	$ —	$ —
Total					
Gross Revenue[3]	**$ 44.18**	$ 51.19	$ 37.83	$ 38.00	$ 49.63
Royalties	**$ 7.62**	$ 8.69	$ 6.66	$ 6.65	$ 8.46
Production and Operating Costs[3]	**$ 9.51**	$ 10.07	$ 8.86	$ 9.85	$ 9.15
Operating netback	**$ 27.05**	$ 32.43	$ 22.31	$ 21.50	$ 32.02

(1) The operating netback includes results from Upstream Exploration and Production and excludes results from Upstream Infrastructure and Marketing. Operating netback is a non-GAAP measure. Refer to the Reader Advisories for further details.
(2) Includes associated co-products converted to boe and mcf.
(3) Transportation expenses have been deducted from both gross revenue and production and operating costs to reflect the actual price received at the oil and gas lease.
(4) Includes offshore transportation costs shown separately from price received.
(5) Includes sulphur sales revenues/royalties.
(6) Alberta Gas Cost Allowance reported exclusively as gas royalties.
(7) Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for financial statement purposes.

Production History

Average Gross Daily Production[1]	Year Ended Dec 31, 2017	Three Months Ended Dec 31, 2017	Sept 30, 2017	June 30, 2017	Mar 31, 2017
Canada - Western Canada					
Light and Medium Crude Oil *(mbbls/day)*	**12.1**	11.0	11.1	11.8	14.5
Heavy Crude Oil *(mbbls/day)*	**44.4**	42.3	44.1	43.1	48.0
Bitumen *(mbbls/day)*	**119.1**	120.9	117.7	117.4	120.6
Conventional Natural Gas *(mmcf/day)*	**378.2**	341.8	379.5	382.2	409.8
NGL *(mbbls/day)*	**10.5**	11.7	11.4	10.8	8.0
Canada - Atlantic					
Light and Medium Crude Oil *(mbbls/day)*	**34.0**	33.0	25.7	38.0	39.6
China - Asia Pacific[2]					
Light and Medium Crude Oil *(mbbls/day)*	**5.3**	2.6	5.9	6.2	6.6
Conventional Natural Gas *(mmcf/day)*	**152.9**	176.5	168.6	132.6	133.3
NGL *(mbbls/day)*	**7.0**	7.4	7.9	6.4	6.2
Indonesia - Asia Pacific[3]					
Conventional Natural Gas *(mmcf/day)*	**8.0**	16.6	15.3	—	—
NGL *(mbbls/day)*	**0.6**	2.3	—	—	—
Total Gross Production *(mboe/day)*	**322.9**	320.4	317.7	319.5	334.0

(1) Total production volumes for 2017, for each product type, are set forth in the Reconciliation of Gross Proved Plus Probable Reserves table.

(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.

Producing and Non-Producing Wells[1][2][3]

Producing Wells	Oil Wells Gross	Oil Wells Net	Natural Gas Wells Gross	Natural Gas Wells Net	Total Gross	Total Net
Canada						
Alberta	1,435	1,221	2,080	1,488	3,515	2,709
Saskatchewan	2,757	2,675	224	221	2,981	2,896
British Columbia	2	1	150	138	152	139
Newfoundland	22	6	—	—	22	6
	4,216	3,903	2,454	1,847	6,670	5,750
International						
China	—	—	10	5	10	5
Indonesia	—	—	4	2	4	2
	—	**—**	**14**	**7**	**14**	**7**
As at December 31, 2017	**4,216**	**3,903**	**2,468**	**1,854**	**6,684**	**5,757**

Non-Producing Wells	2017 Oil Wells Gross	Oil Wells Net	Natural Gas Wells Gross	Natural Gas Wells Net	Total Gross	Total Net
Canada						
Alberta	1,984	1,830	1,245	1,024	3,229	2,854
Saskatchewan	4,294	4,129	213	192	4,507	4,321
British Columbia	1	—	36	22	37	22
As at December 31, 2017	**6,279**	**5,959**	**1,494**	**1,238**	**7,773**	**7,197**

(1) The number of gross wells is the total number of wells in which the Company owns a working interest. The number of net wells is the sum of the fractional interests owned in the gross wells. Productive wells are those producing or capable of producing at December 31, 2017.

(2) The above table does not include producing wells in which the Company has no working interest but does have a royalty interest. At December 31, 2017, the Company had a royalty interest in 986 wells, of which 478 were oil producers and 508 were gas producers.

(3) For purposes of the table, multiple completions are counted as a single well. Where one of the completions in a given well is an oil completion, the well is classified as an oil well. In 2017, there were 1,125 gross and 1,033 net oil wells and 100 gross and 85 net natural gas wells that were completed in two or more formations and from which production is not commingled.

Of the 18 mmboe of Proved Developed Non-Producing reserves as of year-end 2017, approximately 15 mmboe are associated with wells drilled in 2017 that will be placed on production in 2018 and 2019. The remaining volumes are associated with optimization programs within existing fields scheduled over the next five years. Because the remaining capital is small relative to drilling and completion costs the associated reserves are considered developed. There are no other non-producing wells attributed with material reserves.

Landholdings

Developed Acreage *(thousands of acres)*	**Gross**	**Net**
Western Canada		
Alberta	2,056	1,716
Saskatchewan	459	440
British Columbia	44	42
	2,559	2,198
Atlantic	54	20
	2,613	2,218
China	17	7
Indonesia	1	—
As at December 31, 2017	**2,631**	**2,225**

Undeveloped Acreage *(thousands of acres)*	**Gross**	**Net**
Western Canada		
Alberta	2,558	2,268
Saskatchewan	603	597
British Columbia	202	169
	3,363	3,034
Northwest Territories and Arctic	471	458
Atlantic	2,749	1,706
	6,583	5,198
China	105	52
Indonesia	2,977	2,607
Taiwan	1,904	1,428
As at December 31, 2017	**11,569**	**9,285**

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

The Company has commitments totaling approximately $88 million related to exploration to be completed in Atlantic between 2022 and 2023. In addition, the Company has approximately $48 million of commitments related to exploration in the Northwest Territories by 2021. Failure to complete the necessary work commitment may result in the Company forfeiting the right to further exploration activity on the undeveloped land.

As at December 31, 2017, over the next 12 months, development rights to approximately 305,435 acres, or less than four percent, of the Company's net undeveloped landholdings in Canada will be subject to expiry.

The Company holds interests in a diverse portfolio of undeveloped petroleum assets in Western Canada, Atlantic, Asia Pacific, the Northwest Territories and the Arctic. As part of its active portfolio management, the Company continually reviews the economic viability of its undeveloped properties using industry-standard economic evaluation techniques and pricing and economic environment assumptions. Each year,as part of this active management process, some properties are selected for further development activities, while others are held in abeyance, sold, swapped or relinquished back to the mineral rights owner. There is no guarantee that commercial reserves will be discovered or developed on these properties.

Abandonment and Reclamation Costs

There are no significant abandonment or reclamation costs and no unusually high expected development costs or operating costs that have affected or that the Company reasonably expects to affect anticipated development or production activities on properties with no attributed reserves. For further information on abandonment and reclamation costs in respect of the Company's properties, please refer to Note 16 of the Company's audited consolidated financial statements for the year ended December 31, 2017.

Drilling Activity - Number of Wells Drilled

	Year Ended December 31, 2017							
	Western Canada		Atlantic		China		Indonesia	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration								
Oil	2.0	2.0	3.0	1.6	—	—	—	—
Gas	3.0	3.0	—	—	—	—	—	—
	5.0	5.0	3.0	1.6	—	—	—	—
Development								
Oil	100.0	98.0	3.0	2.1	—	—	—	—
Gas	24.0	21.0	—	—	—	—	—	—
	124.0	119.0	3.0	2.1	—	—	—	—
	129.0	**124.0**	**6.0**	**3.7**	**—**	**—**	**—**	**—**
Stratigraphic Test Wells	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Service Wells	**9.0**	**9.0**	**1.0**	**0.7**	**—**	**—**	**—**	**—**

Costs Incurred

($millions)	Total	Western Canada	Atlantic	Total Canada	China	Indonesia [1]
Property acquisition - Unproven	55	55	—	55	—	—
Property acquisition - Proven	18	18	—	18	—	—
Exploration	167	70	87	157	10	—
Development	1,454	927	467	1,394	10	50
2017	**1,694**	**1,070**	**554**	**1,624**	**20**	**50**

(1) Capital expenditures related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.

Oil and Gas Reserves Disclosure

Overview

Husky's oil and gas reserves are estimated in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("COGEH"), and the reserves data disclosed conforms with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). All of Husky's oil and gas reserves are prepared by internal reserves evaluation staff using a formalized process for determining, approving and booking reserves. This process requires all reserves evaluations to be done on a consistent basis using established definitions and guidelines. Approval of individually significant reserves changes requires review by an internal panel of expert geoscientists and qualified reserves evaluators. The Audit Committee of the Board of Directors has examined Husky's procedures for assembling and reporting reserves data and other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has approved, on the recommendation of the Audit Committee, the content of Husky's disclosure of its reserves data and other oil and gas information.

The following oil and gas reserves disclosure dated March 1, 2018 has been prepared in accordance with NI 51 101 effective December 31, 2017. The reserves information prepared in accordance with the rules of the U.S. Financial Accounting Standards Board and the SEC (collectively, the "U.S. Rules") is included in the Company's Form 40-F, which is available at www.sec.gov or on the Company's website at www.huskyenergy.com. The material differences between reserves quantities disclosed under NI 51 101 and those disclosed under the U.S. Rules is that NI 51-101 requires the determination of reserves quantities to be based on forecast pricing assumptions whereas the U.S. Rules require the determination of reserves quantities to be based on constant price assumptions calculated using a 12-month average price for the year (sum of the benchmark price on the first calendar day of each month in the year divided by 12).

Note that the numbers in each column of the tables throughout this section may not add due to rounding. Unless otherwise noted in this document, all provided reserves estimates have an effective date of December 31, 2017.

Independent Audit or Evaluation of Oil and Gas Reserves

Sproule Associates Ltd. ("Sproule"), an independent firm of qualified oil and gas reserves evaluation engineers, was engaged to conduct an audit of Husky's crude oil, natural gas and NGL reserves estimates. Sproule issued an audit opinion stating that Husky'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 COGEH.

Disclosure of Oil and Gas Information

Unless otherwise noted in this document, all provided reserves estimates have a preparation date of January 31, 2018 and an effective date of December 31, 2017 and are Husky's total proved and probable reserves. Gross reserves or gross production are reserves or production attributable to Husky's working interest prior to deduction of royalties; net reserves or net production are reserves or production net of such royalties. Gross or net production reported refers to sales volume, unless otherwise indicated. Unless otherwise noted, production and reserves figures are stated on a gross basis. Unless otherwise indicated, oil and gas commodity prices are quoted after the effects of hedging gains and losses. Unless otherwise indicated, all financial information is in accordance with IFRS as issued by the International Accounting Standards Board.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Bitumen reserves include reserves from thermal projects in Husky's Lloydminster area. These projects also contain heavy oil that is lighter and less viscous than typical bitumen.

Exemption Under National Instrument 51-101

Husky sought and was granted by the Canadian Securities Administrators an exemption from the requirement under NI 51-101 to involve independent qualified oil and gas reserves evaluators or auditors. Notwithstanding this exemption, Husky involves independent qualified reserves auditors as part of Husky's corporate governance practices. The involvement of these independent qualified reserves auditors helps ensure that the Company's internal oil and gas reserves estimates are materially correct.

The reliability of Husky's internally generated oil and gas reserves data is not materially less than would be afforded by Husky involving independent qualified reserves evaluators to evaluate the reserves data. Husky's reserves are prepared within each business unit by qualified reserves evaluators. These evaluators are also responsible for the management of the assets, and therefore their knowledge of and experience with the reserves data are superior to those of external reserves evaluators. Husky employs a number of quality assurance measures to ensure that reserves estimates are prepared in accordance with all requirements of applicable securities regulators and not influenced by self-interest or management activities of the internal reserves evaluation staff. Husky's independent reserves auditors also review and assess Husky's reserves process to ensure that it is complete.

Summary of Oil and Natural Gas Reserves
As at December 31, 2017
Forecast Prices and Costs

Canada

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbls)*	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved								
Developed Producing	59.7	50.5	61.6	59.2	150.5	139.9	271.8	249.5
Developed Non-producing	1.0	0.8	2.2	2.1	11.9	11.4	15.1	14.3
Undeveloped	60.8	57.6	—	—	585.0	509.8	645.9	567.4
Total Proved	121.5	108.8	63.8	61.3	747.4	661.1	932.7	831.2
Probable	105.9	85.0	21.8	21.0	861.8	704.4	989.5	810.4
Total Proved Plus Probable	**227.4**	**193.9**	**85.6**	**82.3**	**1,609.2**	**1,365.5**	**1,922.1**	**1,641.6**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	811.4	702.0	37.0	27.1	444.0	393.6
Developed Non-producing	12.2	9.8	0.8	0.6	17.9	16.6
Undeveloped	350.6	326.6	3.6	3.2	707.9	625.0
Total Proved	1,174.1	1,038.3	41.4	30.9	1,169.8	1,035.1
Probable	422.5	382.0	7.5	5.9	1,067.4	880.0
Total Proved Plus Probable	**1,596.7**	**1,420.3**	**48.9**	**36.8**	**2,237.2**	**1,915.2**

China

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved								
Developed Producing	—	—	—	—	—	—	—	—
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	—	—	—	—	—	—	—	—
Probable	—	—	—	—	—	—	—	—
Total Proved Plus Probable	—	—	—	—	—	—	—	—

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	397.9	378.0	14.0	13.3	80.3	76.3
Developed Non-producing	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—
Total Proved	397.9	378.0	14.0	13.3	80.3	76.3
Probable	214.0	212.6	7.6	7.6	43.2	43.0
Total Proved Plus Probable	**611.9**	**590.6**	**21.6**	**20.9**	**123.6**	**119.3**

Indonesia

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved								
Developed Producing	—	—	—	—	—	—	—	—
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	—	—	—	—	—	—	—	—
Probable	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total Proved Plus Probable	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	163.0	117.7	6.9	4.9	34.1	24.6
Developed Non-producing	—	—	—	—	—	—
Undeveloped	101.0	69.2	—	—	16.8	11.5
Total Proved	264.0	186.9	6.9	4.9	50.9	36.1
Probable	138.5	87.4	2.0	0.8	25.1	15.4
Total Proved Plus Probable	**402.5**	**274.3**	**9.0**	**5.7**	**76.1**	**51.5**

Total

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved								
Developed Producing	59.7	50.5	61.6	59.2	150.5	139.9	271.8	249.5
Developed Non-producing	1.0	0.8	2.2	2.1	11.9	11.4	15.1	14.3
Undeveloped	60.8	57.6	—	—	585.0	509.8	645.9	567.4
Total Proved	121.5	108.8	63.8	61.3	747.4	661.1	932.7	831.2
Probable	105.9	85.0	21.8	21.0	861.8	704.4	989.5	810.4
Total Proved Plus Probable	**227.4**	**193.9**	**85.6**	**82.3**	**1,609.2**	**1,365.5**	**1,922.1**	**1,641.6**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	1,372.3	1,197.7	57.9	45.3	558.4	494.5
Developed Non-producing	12.2	9.8	0.8	0.6	17.9	16.6
Undeveloped	451.6	395.8	3.6	3.2	724.7	636.5
Total Proved	1,836.1	1,603.2	62.4	49.1	1,301.1	1,147.6
Probable	775.0	681.9	17.1	14.3	1,135.7	938.4
Total Proved Plus Probable	**2,611.1**	**2,285.2**	**79.5**	**63.4**	**2,436.8**	**2,085.9**

Future Net Revenue Tables

Summary of Net Present Values of Future Net Revenue - Before Income Taxes and Discounted
As at December 31, 2017
Forecast Prices and Costs

Canada

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	0%	5%	10%	15%	20%	*($/boe)*
Proved						
Developed Producing	1,926	4,624	4,571	4,230	3,892	11.61
Developed Non-producing[(1)]	(546)	(234)	(99)	(35)	(3)	(5.99)
Undeveloped	16,466	7,622	4,167	2,355	1,252	6.67
Total Proved	17,846	12,013	8,639	6,550	5,141	8.35
Probable	33,740	15,213	8,867	5,864	4,180	10.08
Total Proved Plus Probable	**51,586**	**27,226**	**17,506**	**12,414**	**9,321**	**9.14**

(1) In the Heavy Oil properties there are over 7,000 wells with no reserves assigned that carry surface land, maintenance and property taxes that also form part of each non-producing property's (that have reserves) operating costs. Accordingly these costs have been included in the reserves reports in the Proved Developed Non-producing category.

China

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	0%	5%	10%	15%	20%	*($/boe)*
Proved						
Developed Producing	4,706	4,045	3,540	3,146	2,831	46.38
Developed Non-producing	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—
Total Proved	4,706	4,045	3,540	3,146	2,831	46.38
Probable	2,382	1,416	864	531	320	20.08
Total Proved Plus Probable	**7,089**	**5,461**	**4,404**	**3,676**	**3,151**	**36.90**

Indonesia

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	0%	5%	10%	15%	20%	*($/boe)*
Proved						
Developed Producing	657	535	449	387	341	18.28
Developed Non-producing	—	—	—	—	—	—
Undeveloped	285	227	184	151	125	15.93
Total Proved	943	762	633	538	466	17.53
Probable	519	349	244	176	130	15.91
Total Proved Plus Probable	**1,462**	**1,111**	**877**	**714**	**596**	**17.05**

Total

($ millions)	Before Income Taxes and Discounted at (%/year) 0%	5%	10%	15%	20%	Unit Value Discounted at 10% ($/boe)
Proved						
Developed Producing	7,290	9,203	8,560	7,763	7,064	17.31
Developed Non-producing[(1)]	(546)	(234)	(99)	(35)	(3)	(5.99)
Undeveloped	16,751	7,849	4,351	2,505	1,377	6.84
Total Proved	23,495	16,819	12,812	10,233	8,438	11.16
Probable	36,641	16,979	9,975	6,570	4,630	10.63
Total Proved Plus Probable	**60,136**	**33,797**	**22,787**	**16,804**	**13,068**	**10.92**

(1) In the Heavy Oil properties there are over 7,000 wells with no reserves assigned that carry surface land, maintenance and property taxes that are part of each producing property's (that have reserves) operating costs. Accordingly these costs have been included in the reserves reports in the Proved Developed Non-producing category.

Summary of Net Present Values of Future Net Revenue - After Income Taxes and Discounted
As at December 31, 2017
Forecast Prices and Costs

Canada

($ millions)	After Income Taxes and Discounted at (%/year) 0%	5%	10%	15%	20%
Proved					
Developed Producing	1,406	3,341	3,289	3,037	2,790
Developed Non-producing[1]	(399)	(171)	(74)	(27)	(4)
Undeveloped	11,991	5,320	2,708	1,340	511
Total Proved	12,998	8,489	5,924	4,349	3,297
Probable	24,446	10,877	6,272	4,108	2,903
Total Proved Plus Probable	**37,444**	**19,366**	**12,197**	**8,458**	**6,200**

(1) In the Heavy Oil properties there are over 7,000 wells with no reserves assigned that carry surface land, maintenance and property taxes that are part of each producing property's (that have reserves) operating costs. Accordingly these costs have been included in the reserves reports in the Proved Developed Non-producing category.

China

($ millions)	After Income Taxes and Discounted at (%/year) 0%	5%	10%	15%	20%
Proved					
Developed Producing	3,408	2,934	2,571	2,287	2,060
Developed Non-producing	—	—	—	—	—
Undeveloped	—	—	—	—	—
Total Proved	3,408	2,934	2,571	2,287	2,060
Probable	1,750	1,023	604	350	190
Total Proved Plus Probable	**5,159**	**3,956**	**3,175**	**2,637**	**2,250**

Indonesia

($ millions)	After Income Taxes and Discounted at (%/year) 0%	5%	10%	15%	20%
Proved					
Developed Producing	513	430	370	326	292
Developed Non-producing	—	—	—	—	—
Undeveloped	193	154	125	103	86
Total Proved	706	584	495	429	378
Probable	319	214	148	105	76
Total Proved Plus Probable	**1,025**	**798**	**644**	**534**	**454**

Total

($ millions)	After Income Taxes and Discounted at (%/year) 0%	5%	10%	15%	20%
Proved					
Developed Producing	5,327	6,704	6,230	5,650	5,142
Developed Non-producing[1]	(399)	(171)	(74)	(27)	(4)
Undeveloped	12,184	5,474	2,834	1,443	597
Total Proved	17,112	12,007	8,991	7,065	5,735
Probable	**26,515**	**12,113**	**7,025**	**4,564**	**3,169**
Total Proved Plus Probable	**43,627**	**24,120**	**16,015**	**11,629**	**8,904**

(1) In the Heavy Oil properties there are over 7,000 wells with no reserves assigned that carry surface land, maintenance and property taxes that are part of each producing property's (that have reserves) operating costs. Accordingly these costs have been included in the reserves reports in the Proved Developed Non-producing category.

Total Future Net Revenue for Total Proved Plus Probable Reserves - Undiscounted
As at December 31, 2017
Forecast Prices and Costs

($ millions)	Revenue	Royalties	Operating Costs	Development Costs	Abandonment and Reclamation Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Canada								
Total Proved	68,342	8,847	24,978	10,328	6,344	17,846	4,848	12,998
Total Proved Plus Probable	150,446	24,591	46,579	21,029	6,661	51,586	14,142	37,444
China								
Total Proved	5,883	327	716	4	130	4,706	1,298	3,408
Total Proved Plus Probable	9,470	501	1,231	469	181	7,089	1,930	5,159
Indonesia								
Total Proved	2,778	819	928	48	41	943	237	706
Total Proved Plus Probable	4,489	1,491	1,335	145	55	1,462	437	1,025
Total								
Total Proved	77,004	9,993	26,621	10,379	6,515	23,495	6,383	17,112
Total Proved Plus Probable	164,405	26,583	49,145	21,643	6,897	60,136	16,509	43,627

Future Net Revenue by Product Type
As at December 31, 2017
Forecast Prices and Costs

	Future Net Revenue Before Income Taxes (discounted at 10%/year)[1]							
	Canada		China		Indonesia		Total	
	($ millions)	*($/boe)*	*($ millions)*	*($/boe)*	*($ millions)*	*($/boe)*	*($ millions)*	*($/boe)*
Total Proved								
Light & Medium Crude Oil	817	7.50	—	—	—	—	817	7.50
Heavy Crude Oil	67	1.09	—	—	—	—	67	1.09
Bitumen	7,203	10.90	—	—	—	—	7,203	10.90
Total Oil	8,087	9.73	—	—	—	—	8,087	9.73
Conventional Natural Gas	552	2.71	3,540	46.38	633	17.53	4,725	14.94
Total Proved	**8,639**	**8.35**	**3,540**	**46.38**	**633**	**17.53**	**12,812**	**11.16**
Total Proved Plus Probable								
Light & Medium Crude Oil	2,989	15.42	—	—	—	—	2,989	15.42
Heavy Crude Oil	416	5.05	—	—	—	—	416	5.05
Bitumen	13,165	9.64	—	—	—	—	13,165	9.64
Total Oil	16,570	10.09	—	—	—	—	16,570	10.09
Conventional Natural Gas	936	3.42	4,404	36.90	877	17.05	6,217	13.99
Total Proved Plus Probable	**17,506**	**9.14**	**4,404**	**36.90**	**877**	**17.05**	**22,787**	**10.92**

(1) By-products, including solution gas, NGL and other associated by-products, are included in their main product group (natural gas or oil).

Pricing Assumptions

Except as noted below, the pricing assumptions disclosed in the following table were derived using the industry averages prescribed by McDaniel and Associates Consultants Ltd., Sproule Associates Limited and GLJ Petroleum Consultants Ltd. China and Indonesia gas prices are derived from the GSAs specific to each set of projects. For historical prices realized during 2017, see "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Oil and Gas Activities – Operating Netback Analysis".

	Light Crude Oil			Medium Crude Oil	Heavy Crude Oil
	WTI *(U.S. $/bbl)*	Brent *(U.S. $/bbl)*	Edmonton *(Cdn $/bbl)*	Hardisty Bow River *(Cdn $/bbl)*	Hardisty Heavy API *(Cdn $/bbl)*
Historical					
2017	50.95	54.28	62.91	50.84	44.36
Forecast					
2018	57.50	62.33	68.60	51.23	43.55
2019	60.90	63.93	72.02	57.52	49.90
2020	64.13	66.13	74.48	61.56	54.29
2021	68.33	70.37	78.60	65.27	57.72
2022	71.19	73.23	80.84	67.35	59.67
2023	73.15	75.21	82.83	69.24	61.44
2024	75.16	77.23	85.17	71.39	63.51
2025	77.17	79.26	87.53	73.55	65.56
2026	79.01	81.15	89.66	75.49	67.38
2027	80.60	82.75	91.49	77.12	68.90
Thereafter	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr

	Bitumen	Natural Gas	Natural Gas Liquids		
	Hardisty WCS *(Cdn $/bbl)*	AECO *(Cdn $/mmbtu)*	Edmonton Propane *(Cdn $/bbl)*	Edmonton Butane *(Cdn $/bbl)*	Edmonton Condensate *(Cdn $/bbl)*
Historical					
2017	50.56	2.30	28.77	44.45	66.85
Forecast					
2018	50.61	2.43	35.69	51.29	72.41
2019	56.59	2.77	35.82	52.29	74.90
2020	60.86	3.19	34.85	53.92	77.07
2021	64.56	3.48	36.07	56.70	81.07
2022	66.63	3.67	35.89	58.32	83.32
2023	68.49	3.76	36.28	59.72	85.35
2024	70.63	3.85	37.39	61.42	87.75
2025	72.79	3.93	38.50	63.08	90.13
2026	74.72	4.02	39.52	64.60	92.32
2027	76.31	4.10	40.37	65.95	94.21
Thereafter	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr

	Asia Pacific			
	China	Indonesia		
	Natural Gas *(U.S. $/mcf)* (1)	Natural Gas *(U.S. $/mcf)* (1)	Inflation rates(2)	Exchange rates(3)
Historical				
2017	10.28	6.59	—	0.77
Forecast				
2018	10.38	7.35	—	0.79
2019	10.96	7.18	2.00	0.80
2020	11.69	7.19	2.00	0.82
2021	11.46	7.36	2.00	0.83
2022	10.37	7.53	2.00	0.84
2023	10.49	7.68	2.00	0.84
2024	10.53	7.84	2.00	0.84
2025	10.58	7.99	2.00	0.84
2026	10.62	8.08	2.00	0.84
2027	10.72	8.16	2.00	0.84
Thereafter	2.00%/yr	2.00%/yr	2.00	0.84

(1) Natural gas prices in China and Indonesia have been updated from the prior year values due to negotiations with the purchasers and are the volume weighted average based on the various GSAs.

(2) Inflation rates represent a percentage for forecasting costs.

(3) Exchange rates used to generate the benchmark reference prices are quoted in U.S. dollar to Canadian dollar.

Reconciliation of Gross Proved Reserves

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Canada - Western Canada							
End of 2016	33.5	63.3	648.1	744.9	1,516.9	45.1	1,042.8
Technical Revisions	4.7	17.6	6.2	28.5	0.8	(0.4)	28.2
Economic Factors	—	(0.2)	(0.2)	(0.5)	(9.0)	(0.2)	(2.1)
Acquisitions	—	—	—	—	0.6	—	0.1
Dispositions	(10.8)	(0.9)	—	(11.6)	(294.5)	(0.9)	(61.6)
Discoveries	0.2	0.1	—	0.4	8.6	0.3	2.2
Extensions & Improved Recovery	1.4	—	136.9	138.3	88.8	1.3	154.3
Production	(4.4)	(16.1)	(43.6)	(64.1)	(138.0)	(3.8)	(90.9)
End of 2017	**24.6**	**63.8**	**747.4**	**835.8**	**1,174.1**	**41.4**	**1,073.0**
Canada - Atlantic							
End of 2016	47.5	—	—	47.5	—	—	47.5
Technical Revisions	(3.5)	—	—	(3.5)	—	—	(3.5)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	65.2	—	—	65.2	—	—	65.2
Production	(12.4)	—	—	(12.4)	—	—	(12.4)
End of 2017	**96.8**	**—**	**—**	**96.8**	**—**	**—**	**96.8**
China							
End of 2016	2.0	—	—	2.0	399.9	13.6	82.3
Technical Revisions	(0.1)	—	—	(0.1)	53.8	2.9	11.9
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	(1.9)	—	—	(1.9)	(55.8)	(2.5)	(13.8)
End of 2017	**—**	**—**	**—**	**—**	**397.9**	**14.0**	**80.3**
Indonesia							
End of 2016	—	—	—	—	268.2	7.2	51.9
Technical Revisions	—	—	—	—	(1.2)	—	(0.2)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(2.9)	(0.2)	(0.7)
End of 2017	**—**	**—**	**—**	**—**	**264.0**	**6.9**	**50.9**

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Total							
End of 2016	83.0	63.3	648.1	794.4	2,185.0	65.9	1,224.4
Technical Revisions	1.1	17.6	6.2	25.0	53.3	2.5	36.4
Economic Factors	—	(0.2)	(0.2)	(0.5)	(9.0)	(0.2)	(2.1)
Acquisitions	—	—	—	—	0.6	—	0.1
Dispositions	(10.8)	(0.9)	—	(11.6)	(294.5)	(0.9)	(61.6)
Discoveries	0.2	0.1	—	0.4	8.6	0.3	2.2
Extensions & Improved Recovery	66.6	—	136.9	203.5	88.8	1.3	219.6
Production	(18.8)	(16.1)	(43.6)	(78.5)	(196.8)	(6.6)	(117.8)
End of 2017	**121.5**	**63.8**	**747.4**	**932.7**	**1,836.1**	**62.4**	**1,301.1**

At December 31, 2017, the Company's proved oil and gas reserves were 1,301 mmboe, up from 1,224 mmboe at the end of 2016. The Company's 2017 reserves replacement ratio, defined as net additions of proved reserves divided by total production during the period, was 167 percent excluding economic revisions (165 percent including economic revisions).

Major changes to proved reserves in 2017 included:

- Disposition of 62 mmboe in Western Canada.
- Extensions & 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 in 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 life.

Reconciliation of Gross Probable Reserves

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Canada - Western Canada							
End of 2016	8.2	20.1	1,274.6	1,302.8	423.1	8.2	1,381.5
Technical Revisions	(0.5)	1.9	(425.0)	(423.5)	(24.7)	(0.8)	(428.4)
Economic Factors	0.2	(0.2)	0.2	0.1	(0.3)	—	0.1
Revisions - Transfer to Proved	—	—	(30.3)	(30.3)	(76.9)	(0.7)	(43.8)
Acquisitions	—	—	—	—	0.1	—	—
Dispositions	(2.0)	—	—	(2.0)	(56.7)	(0.9)	(12.4)
Discoveries	0.3	—	—	0.3	4.9	0.2	1.3
Extensions & Improved Recovery	0.3	—	42.3	42.7	153.0	1.6	69.7
Production	—	—	—	—	—	—	—
End of 2017	**6.5**	**21.8**	**861.8**	**890.0**	**422.5**	**7.5**	**967.9**
Canada - Atlantic							
End of 2016	159.7	—	—	159.7	—	—	159.7
Technical Revisions	5.9	—	—	5.9	—	—	5.9
Economic Factors	—	—	—	—	—	—	—
Revisions - Transfer to Proved	(66.2)	—	—	(66.2)	—	—	(66.2)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
End of 2017	**99.4**	**—**	**—**	**99.4**	**—**	**—**	**99.4**
China							
End of 2016	—	—	—	—	118.0	4.3	24.0
Technical Revisions	—	—	—	—	(0.5)	6.2	6.1
Economic Factors	—	—	—	—	—	—	—
Revisions - Transfer to Proved	—	—	—	—	(54.7)	(3.0)	(12.1)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	151.3	—	25.2
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
End of 2017	**—**	**—**	**—**	**—**	**214.0**	**7.6**	**43.2**
Indonesia							
End of 2016	—	—	—	—	139.6	2.1	25.3
Technical Revisions	—	—	—	—	(1.1)	—	(0.2)
Economic Factors	—	—	—	—	—	—	—
Revisions - Transfer to Proved	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
End of 2017	**—**	**—**	**—**	**—**	**138.5**	**2.0**	**25.1**

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Total							
End of 2016	167.9	20.1	1,274.6	1,462.5	680.6	14.5	1,590.5
Technical Revisions	5.5	1.9	(425.0)	(417.6)	(26.3)	5.4	(416.5)
Economic Factors	0.2	(0.2)	0.2	0.1	(0.3)	—	0.1
Revisions - Transfer to Proved	(66.2)	—	(30.3)	(96.5)	(131.6)	(3.7)	(122.2)
Acquisitions	—	—	—	—	0.1	—	—
Dispositions	(2.0)	—	—	(2.0)	(56.7)	(0.9)	(12.4)
Discoveries	0.3	—	—	0.3	156.2	0.2	26.5
Extensions & Improved Recovery	0.3	—	42.3	42.7	153.0	1.6	69.7
Production	—	—	—	—	—	—	—
End of 2017	**105.9**	**21.8**	**861.8**	**989.5**	**775.0**	**17.1**	**1,135.7**

Major changes to probable reserves in 2017 included:

- Disposition of 12 mmboe in Western Canada.
- Extensions & Improved Recovery additions of 70 mmbbls including 42 mmbbls for three new Lloyd thermal bitumen SAGD projects, and 25 mmboe in Ansell from new locations.
- Technical revisions of negative 441 mmbbls in bitumen from the delaying of development of future phases of the Sunrise Energy Project beyond the next five years due to continued low bitumen prices. Technical revisions resulting in the addition of 20 mmbbls in the thermal projects with improved performance were offset by negative revisions of 5 mmboe in Western Canada gas.
- Discoveries of 151 bcf of conventional natural gas in China for which Husky has sanctioned the completion and tie-in of an additional field that has received government approval.

Reconciliation of Gross Proved Plus Probable Reserves

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Canada - Western Canada							
End of 2016	41.7	83.3	1,922.7	2,047.7	1,939.9	53.3	2,424.3
Technical Revisions	4.2	19.6	(418.8)	(395.1)	(23.9)	(1.2)	(400.2)
Economic Factors	0.1	(0.5)	—	(0.3)	(9.3)	(0.2)	(2.1)
Revisions - Transfer to Proved	—	—	(30.3)	(30.3)	(76.9)	(0.7)	(43.8)
Acquisitions	—	—	—	—	0.7	—	0.2
Dispositions	(12.8)	(0.9)	—	(13.7)	(351.2)	(1.8)	(74.0)
Discoveries	0.5	0.1	—	0.7	13.5	0.5	3.4
Extensions & Improved Recovery	1.7	—	179.2	180.9	241.8	2.9	224.1
Production	(4.4)	(16.1)	(43.6)	(64.1)	(138.0)	(3.8)	(90.9)
End of 2017	**31.1**	**85.6**	**1,609.2**	**1,725.8**	**1,596.7**	**48.9**	**2,040.9**
Canada - Atlantic							
End of 2016	207.2	—	—	207.2	—	—	207.2
Technical Revisions	2.5	—	—	2.5	—	—	2.5
Economic Factors	—	—	—	—	—	—	—
Revisions - Transfer to Proved	(66.2)	—	—	(66.2)	—	—	(66.2)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	65.2	—	—	65.2	—	—	65.2
Production	(12.4)	—	—	(12.4)	—	—	(12.4)
End of 2017	**196.3**	**—**	**—**	**196.3**	**—**	**—**	**196.3**
China							
End of 2016	2.0	—	—	2.0	517.9	17.9	106.3
Technical Revisions	(0.1)	—	—	(0.1)	53.3	9.2	18.0
Economic Factors	—	—	—	—	—	—	—
Revisions - Transfer to Proved	—	—	—	—	(54.7)	(3.0)	(12.1)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	151.3	—	25.2
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	(1.9)	—	—	(1.9)	(55.8)	(2.5)	(13.8)
End of 2017	**—**	**—**	**—**	**—**	**611.9**	**21.6**	**123.6**
Indonesia							
End of 2016	—	—	—	—	407.8	9.2	77.2
Technical Revisions	—	—	—	—	(2.4)	—	(0.4)
Economic Factors	—	—	—	—	—	—	—
Revisions - Transfer to Proved	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(2.9)	(0.2)	(0.7)
End of 2017	**—**	**—**	**—**	**—**	**402.5**	**9.0**	**76.1**

	Light & Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Bitumen (mmbbls)	Total Oil (mmbbls)	Conventional Natural Gas (bcf)	Natural Gas Liquids (mmbbls)	Total (mmboe)
Total							
End of 2016	250.9	83.3	1,922.7	2,256.9	2,865.7	80.4	2,814.9
Technical Revisions	6.6	19.6	(418.8)	(392.6)	27.0	8.0	(380.1)
Economic Factors	0.1	(0.5)	—	(0.3)	(9.3)	(0.2)	(2.1)
Revisions - Transfer to Proved	(66.2)	—	(30.3)	(96.5)	(131.6)	(3.7)	(122.2)
Acquisitions	—	—	—	—	0.7	—	0.2
Dispositions	(12.8)	(0.9)	—	(13.7)	(351.2)	(1.8)	(74.0)
Discoveries	0.5	0.1	—	0.7	164.8	0.5	28.7
Extensions & Improved Recovery	67.0	—	179.2	246.2	241.8	2.9	289.3
Production	(18.8)	(16.1)	(43.6)	(78.5)	(196.8)	(6.6)	(117.8)
End of 2017	**227.4**	**85.6**	**1,609.2**	**1,922.1**	**2,611.1**	**79.5**	**2,436.8**

Undeveloped Reserves

Undeveloped reserves are attributed internally in accordance with standards and procedures contained in the COGEH. Proved undeveloped oil and gas reserves are those reserves that can be estimated with a high degree of certainty to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Probable undeveloped oil and gas reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. There are numerous uncertainties inherent in estimating quantities of crude oil and natural gas reserves. Classifications of reserves as proved or probable are only attempts to define the degree of uncertainty associated with the estimates. In addition, whereas proved reserves are those reserves that can be estimated with a high degree of certainty to be economically producible, probable reserves are those reserves that are as likely as not to be recovered. Therefore, probable reserves estimates, by definition, have a higher degree of uncertainty than proved reserves.

Approximately 46 percent of Husky's gross proved undeveloped reserves are assigned to the Sunrise Energy Project. Production from Phase I of the project started in March 2015, and wells will be drilled in the future to keep the plant at full capacity. Approximately 34 percent of Husky's gross proved undeveloped reserves are assigned to 12 heavy oil thermal projects in the Lloydminster area that are classified as bitumen. Approximately eight percent of Husky's gross proved undeveloped reserves are assigned to the liquids-rich Ansell area. Approximately two percent of Husky's gross proved undeveloped reserves are assigned to the International area. And approximately eight percent of Husky's gross proved undeveloped reserves are assigned to the West White Rose Project fields and were added in 2017 with the sanctioning of the project by Husky and its partners.

Husky funds capital programs by cash generated from operating activities, cash on hand, equity issuances and short-term and long term debt. Decisions on the priority of developing the various proved undeveloped and probable undeveloped reserves are based on various factors including economic conditions, technical performance, facility capacity, commercial considerations and size of the development program. The development opportunities are pursued at a pace dependent on capital availability and its allocation, but Husky generally seeks, in accordance with its business plan, to develop its proved and probable undeveloped Ansell and other resource plays reserves over five and seven-year time periods, respectively. As at December 31, 2017, there were no material proved undeveloped reserves that have remained undeveloped for greater than five years, except as described below.

The Sunrise Energy Project proved undeveloped thermal bitumen reserves are scheduled to be developed and produced over the next 50 years to fully utilize the steam plant and processing capacity over the life of the current facilities. Similarly, the probable undeveloped bitumen reserves are scheduled to be developed and produced over the next 50 years which includes capital spending on facility debottlenecks, expansions and additions within the next five years. For the Lloyd thermal bitumen projects one project is scheduled to start up in the first quarter of 2019 while three new Lloyd thermal bitumen projects received regulatory approval in 2017 and are scheduled to be brought on line in 2020. The Lloyd thermal bitumen proved and probable undeveloped locations and Tucker bitumen probable locations are scheduled to be developed over the next one to 20 years to utilize each of the project's steam and processing capacities. The West White Rose Project is scheduled to have the first proved undeveloped reserves placed on production in 2022. The remaining proved and probable undeveloped locations are scheduled to be placed on production by 2027. Proved undeveloped reserves in Madura are scheduled to be brought on production in 2019 while probable undeveloped reserves for Liuhua 29-1 are scheduled to be brought on production in 2021. Ansell's proved and probable undeveloped locations are scheduled to be developed over the next five and seven years, respectively, all in keeping with the business plan.

Proved Undeveloped Reserves

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
2015	4.5	10.4	0.1	5.0	180.7	467.8	185.3	483.2
2016	—	5.7	—	0.3	9.1	488.3	9.1	494.3
2017	**61.8**	**60.8**	**—**	**—**	**136.9**	**585.0**	**198.7**	**645.9**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
2015	172.5	611.7	0.7	10.4	214.8	595.6
2016	1.6	435.2	—	3.2	9.4	570.0
2017	**71.9**	**451.6**	**1.0**	**3.6**	**211.6**	**724.7**

Probable Undeveloped Reserves

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
2015	—	106.4	—	4.9	0.1	1,235.2	0.1	1,346.6
2016	11.8	133.7	—	0.1	1.3	1,234.0	13.1	1,367.7
2017	**0.3**	**80.8**	**—**	**—**	**42.3**	**810.9**	**42.7**	**891.8**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
2015	143.0	405.4	1.8	8.0	25.7	1,422.2
2016	48.1	345.4	0.4	3.4	21.5	1,428.7
2017	**302.7**	**558.8**	**7.1**	**9.0**	**100.2**	**993.9**

Significant Factors or Uncertainties Affecting Reserves Data

Husky's reserves can be affected significantly by material fluctuations in product pricing, development plans and capital expenditures, operating costs, regulatory changes that impact costs and/or royalties and production performance. Actual product prices may vary significantly from the forecast price assumptions used by the Company to estimate its reserves, altering the allocation and level of capital expenditures, and accelerating or delaying project schedules. As new information is obtained, the above factors that affect costs, royalties and production performance are reviewed and updated accordingly, which may result in positive or negative revisions to reserves. For additional information on risk factors please see "Risk Factors – Reserves Data and Future Net Revenue Estimates".

There are no significant abandonment or reclamation costs and no unusually high expected development costs or operating costs that have affected or that the Company reasonably expects to affect anticipated development or production activities on properties with reserves. For further information on abandonment and reclamation costs in respect of the Company's properties, please refer to Note 16 of the Company's audited consolidated financial statements for the year ended December 31, 2017.

Future Development Costs

The Company expects to fund its future development costs by cash generated from operating activities, cash on hand and short and long-term debt. In addition, the Company has access to additional funding through credit facilities and the issuance of equity through shelf prospectuses, subject to market conditions. The cost associated with this funding would not affect reserves and would not be material in comparison with future net revenues.

The following table includes estimates of the forecasted costs of developing the Company's proved and proved plus probable reserves as at December 31, 2017:

	Canada		China		Indonesia		Total	
Year	Proved Reserves *($ millions)*	Proved Plus Probable Reserves *($ millions)*	Proved Reserves *($ millions)*	Proved Plus Probable Reserves *($ millions)*	Proved Reserves *($ millions)*	Proved Plus Probable Reserves *($ millions)*	Proved Reserves *($ millions)*	Proved Plus Probable Reserves *($ millions)*
2018	1,647	1,691	4	135	28	58	1,679	1,884
2019	1,426	1,629	—	193	20	87	1,446	1,909
2020	1,097	1,237	—	141	—	—	1,097	1,378
2021	935	1,162	—	—	—	—	935	1,162
2022	592	852	—	—	—	—	592	852
Remaining	4,630	14,458	—	—	—	—	4,630	14,458
Total	**10,328**	**21,029**	**4**	**469**	**48**	**145**	**10,379**	**21,643**

Production Estimates

Yearly Production Estimates for 2018

	Light & Medium Crude Oil *(mbbls/day)*	Heavy Crude Oil *(mbbls/day)*	Bitumen *(mbbls/day)*	Total Oil *(mbbls/day)*	Conventional Natural Gas *(mmcf/day)*	Natural Gas Liquids *(mbbls/day)*	Total *(mboe/day)*
Canada							
Total Gross Proved	34.2	35.2	128.5	197.9	240.7	10.0	248.0
Total Gross Probable	6.5	2.7	6.8	16.0	22.5	0.4	20.2
Total Gross Proved Plus Probable	**40.7**	**37.8**	**135.3**	**213.9**	**263.2**	**10.5**	**268.2**
China							
Total Gross Proved	—	—	—	—	186.5	7.6	38.6
Total Gross Probable	—	—	—	—	—	—	—
Total Gross Proved Plus Probable	**—**	**—**	**—**	**—**	**186.5**	**7.6**	**38.6**
Indonesia							
Total Gross Proved	—	—	—	—	38.4	2.6	9.0
Total Gross Probable	—	—	—	—	—	—	—
Total Gross Proved Plus Probable	**—**	**—**	**—**	**—**	**38.4**	**2.6**	**9.0**
Total							
Total Gross Proved	34.2	35.2	128.5	197.9	465.6	20.2	295.7
Total Gross Probable	6.5	2.7	6.8	16.0	22.5	0.4	20.2
Total Gross Proved Plus Probable	**40.7**	**37.8**	**135.3**	**213.9**	**488.1**	**20.6**	**315.8**

No individual property accounts for 20 percent or more of the estimated production disclosed.

Social and Environmental Considerations

Social and Environmental Policy

Husky has a Health, Safety and Environment Policy that affirms its commitment to operational integrity. Operational integrity at Husky means conducting all activities safely and reliably so that the public is protected, impact to the environment is minimized, the health and wellbeing of employees are safeguarded, contractors and customers are safe, and physical assets (such as facilities and equipment) are protected from damage or loss.

The Health, Safety and Environment Committee of the Board of Directors (the "HS&E Committee") is responsible for oversight of the Health, Safety and Environment Policy, oversight of audit results and monitoring compliance with the Company's environmental policies, key performance indicators and regulatory requirements. The mandate of the HS&E Committee is available in the Governance section of the Husky website at www.huskyenergy.com.

To reinforce the Health, Safety and Environment Policy, Husky holds an annual summit for leaders, attended by members of the HS&E Committee and led by the Chief Executive Officer. During the summit, CEO awards are presented for the initiatives that demonstrate the highest level of operational integrity. Guest and internal speakers present on pertinent issues and the latest developments in the field of operational integrity and corporate responsibility.

Husky is committed to upholding high standards of business integrity and seeks to deter wrongdoing and promote transparent, honest and ethical behaviour in all of its business dealings. The Company has a Code of Business Conduct that sets out the standards employees, contractors, officers and directors are expected to meet. The policy includes sections on compliance with laws, avoidance of conflict of interest, proper record-keeping, political contributions, safeguarding company resources, fair competition, avoidance of bribery or other offering of improper payments, guidelines on accepting payments and entertainment, and other matters. The policy is available on the Husky website at www.huskyenergy.com.

Husky has established an anonymous and confidential online reporting tool and toll-free telephone numbers for employees, contractors and other stakeholders to report perceived breaches of the Company's Code of Business Conduct. The Ethics Help Line is hosted by EthicsPoint, an independent service provider. Information from submissions is captured and submitted anonymously to an Ethics Help Line committee made up of legal, audit, security, health, safety and environment, and human resources personnel.

Husky is committed to conducting business fairly, with integrity and in compliance with applicable laws. It has an Anti-Bribery & Anti-Corruption Policy to reinforce the Code of Business Conduct with additional guidance regarding applicable anti-bribery and anti-corruption laws. All officers and employees, including temporary and contract staff, are expected to observe the highest standards of honesty, integrity, diligence and fairness in all business activities.

Husky is an equal opportunity employer committed to an environment free of discrimination, harassment and violence and where respectful treatment is the norm. The Diversity and Respectful Workplace Policy applies to all employees and contractors.

As a responsible member of the communities in which it operates, Husky has a Community Investment Program that supports local charitable organizations. The Community Investment Policy provides guidance with the general goal of ensuring that contributions under the Community Investment Program are supported by a consistent and rigorous decision making process and reflect Husky's core corporate values and business strategy.

Husky has an External Scholarships and Educational Support Policy that encourages advanced education by providing financial assistance to qualified students pursuing studies at a number of post-secondary educational institutions, reinforcing Husky's commitment to support the communities where it operates. The policy includes Husky's Scholarships for Aboriginal Students which assists Aboriginal people in achieving greater career success by encouraging them to pursue an advanced education.

Husky values education and professional development and provides employees with opportunities to continue to develop and advance their skills, knowledge and experience. The Learning and Development Policy sets out guidelines, eligibility and support for employees.

Husky is committed to securing and protecting personnel, physical assets, property and information from criminal, hostile or malicious acts, consistent with its Security Policy. The policy aims to reduce exposure to security risks with the general goal of ensuring the consistent application of security measures within Husky.

Husky is committed to ensuring health and safety at work. The ability of every employee or contractor to perform their particular job duties satisfactorily and safely is critical to Husky's continued success. Husky recognizes that the use of illicit drugs and other mood altering substances, and the inappropriate use of alcohol and medications, can have serious adverse effects on job performance and ultimately on the safety and well-being of employees, contractors, customers, the public and the environment. In light of this, and the safety-sensitive nature of Husky's operations, the Alcohol and Drug Policy outlines the standards and expectations associated with alcohol and other drug use, consistent with Husky's overall safety culture.

The above policies are available to employees and contractors on the Company's intranet. Communication of the policies is provided through direct e-mail and articles published on the Company's intranet. Mandatory training is provided as relevant to the policy and the individual's role via various mechanisms including in-class, web-based and self-serve courses.

Husky Operational Integrity Management System

Husky approaches social responsibility and sustainable development by seeking a balance among economic, environmental and social factors while maintaining growth. Husky strives to find solutions that do not compromise the needs of future generations. In 2008, Husky implemented the Husky Operational Integrity Management System ("HOIMS"). HOIMS is a systematic approach to anticipating, identifying and mitigating hazardous situations within the Company's operations. The implementation of HOIMS has produced tangible business results, including improved performance, fewer incidents and enhanced business value. It incorporates best practices from across the industry, consistent with Husky's commitment to excellence in operational integrity. HOIMS includes 14 fundamental elements; each element contains well defined objectives and expectations that guide Husky to continuously improve operational integrity. Resources are dedicated to the continued execution of HOIMS, and audits are conducted with the general goal of ensuring that HOIMS is effectively integrated into daily operations.

The fundamental elements of HOIMS are:

1. Ensure all levels of management demonstrate leadership and commitment to operational integrity. Define and ensure appropriate accountability for HOIMS throughout the organization.
2. Prevent incidents by identifying and minimizing workplace and personal health risks. Promote and reinforce safe behaviours.
3. Manage risks by performing comprehensive risk assessments to provide essential decision-making information. Develop and implement plans to manage significant risks and impacts to as low as reasonably practical levels.
4. Be prepared for an emergency or security threat. Identify all necessary actions to be taken to protect people, the environment, the organization's assets and reputation in the event of an emergency or security threat.
5. Maintain operations reliability and integrity by use of clearly defined and documented operational, maintenance, inspection and corrosion programs. Seek improvements in process and equipment dependability by systematically eliminating defects and sources of loss.
6. Provide assurance that personnel possess the necessary competencies, knowledge, abilities and behaviours to perform designated tasks and responsibilities effectively, efficiently and safely.
7. Report and investigate incidents. Learn from incidents and use the information to take corrective action and prevent recurrence.
8. Operate responsibly to minimize the environmental impact of operations. Leave a positive legacy behind when operations cease.
9. Ensure that risks and exposures from proposed changes are identified, evaluated and managed to remain at an acceptable level.
10. Identify, maintain and safeguard important information. Ensure personnel can readily access and retrieve information. Promote and encourage constructive dialogue within the organization to share industry recommended practices and acquired knowledge.
11. Ensure conformance with corporate policies and compliance with relevant government regulations. Work constructively to influence proposed laws and regulations, and debate on emerging issues.
12. Design, construct, commission, operate and decommission assets in a healthy, safe, secure, environmentally sound, reliable and efficient manner.
13. Ensure contractors and suppliers perform in a manner that is consistent and compatible with Husky's policies and business performance standards. Ensure contracted services and procured materials meet the requirements and expectations of Husky's standards.
14. Confirm that HOIMS processes are implemented and assess whether they are working effectively. Measure progress and continually improve towards meeting HOIMS objectives, targets, and key performance indicators.

Pipeline Integrity

Husky implements a risk-based Pipeline Integrity Management ("PIM") program across all Husky owned and operated pipelines. The program is a framework that is supported by a suite of documents including but not limited to the Pipeline Operations and Maintenance Procedures Manual ("POMM"), which provides guidelines on the safe operation and maintenance of pipelines. Numerous processes are required and utilized throughout the pipeline lifecycle to ensure a proactive approach to managing the integrity, operations and maintenance of the pipelines.

Processes for the management of pipeline integrity include:

- Risk management program: used to identify the integrity threats throughout the pipelines life cycle, and the risks associated with each threat. Appropriate measures are taken to address these risks and reduce them to as low a level as reasonably practicable.
- Engineering assessments: evaluate the fitness for service of pipelines when changes to design are made in order to proactively mitigate the risk to process safety.
- Failure investigations: establish root cause of any failures and apply the learnings to improve integrity programs.
- Annual pipeline integrity reviews: completed for all pipeline systems to review the effectiveness of integrity programs and where applicable make recommendations for improvement.
- Training: Husky has a Learning Management System ("LMS") which defines mandatory training requirements for all employees. Husky has a web-based PIM and POMM training program on LMS that is available for all employees involved in the operation and maintenance of pipelines.
- Performance targets (number of incidents/1,000 km of pipeline) are set annually.Targets are tracked quarterly by the pipeline steering committee and immediate steps are taken to address any deficiencies.
- PIM program sustainment and continuous improvement: a comprehensive self-assessment process is being implemented to ensure effective sustainment and the continuous improvement of the PIM Program.
- PIM program review: regular review of the PIM program is completed to ensure it aligns with the latest code and regulatory requirements. The reviews also consider Husky experience and pipeline industry standards and practices.

Environmental Protection

Husky's operations are subject to various environmental requirements under federal, provincial, state and local laws and regulations, as well as international conventions. These laws and regulations cover matters such as air emissions, wastewater discharge, non-saline water use, protection of surface water and groundwater, land disturbances and handling and disposal of waste materials. These regulatory requirements have grown in number and complexity over time, covering a broader scope of industry operations and products. In addition to existing requirements, Husky recognizes that there are emerging regulatory frameworks that may have a financial impact on the Company's operations. See "Risk Factors"and "Industry Overview".

Directly and through joint venture partnerships, Husky is a member of several industry associations that collaborate to identify and implement best practices on environmental performance. The International Petroleum Industry Environmental Conservation Association ("IPIECA") produces guidelines that Husky uses to improve its operations and environmental practices, enhance its strategic planning and engage with regulators. Husky is also a member of the International Emissions Trading Association ("IETA") whose objective is to build international policy and market frameworks for reducing GHG emissions at the lowest cost. As a member of the Petroleum Technology Alliance Canada, Husky participates in technology research for energy efficiency and emissions reduction.

In addition, as an active member of the In-situ Water Technology Development Centre, Husky is developing new technologies to reduce energy and water use. Husky dedicates teams to water management issues, with expertise in hydrogeology, surface water aquatics, hydrology, water treatment and drilling waste management. Husky continues to seek ways to conserve and recycle water, including looking at alternative water sources and recycling produced water. At the Tucker Thermal Project, produced water is recycled and make up water is sourced from saline, non-potable groundwater. The Sunrise Energy Project recycles produced water and supplements this with process-affected water from a nearby oil sands operation (after it has been treated) and non-saline groundwater to generate steam for oil recovery.

Ongoing remediation and reclamation work is occurring at approximately 3,000 well sites and facilities. During 2017, Husky spent approximately $136 million on asset retirement obligations ("ARO"), and the Company expects to spend approximately $179 million in 2018 on environmental site closure activities in North America, including abandonment, decommissioning, reclamation and remediation. In Asia Pacific and in accordance with the provisions of the regulations of the People's Republic of China, Husky has deposited funds into separate accounts restricted to the funding of future ARO. As at December 31, 2017, the Company had deposited funds of $192 million of which $95 million related to the Wenchang field and was classified as current liabilities.

The Company completed a review of its ARO provisions, including estimated costs and projected timing of performing the abandonment and retirement operations. The results of this review have been incorporated into the estimated liability as disclosed in Note 16 of the Company's 2017 Audited Consolidated Financial Statements.

Husky has an ongoing environmental monitoring program at owned and leased retail locations and performs remediation where required. Husky also has ongoing monitoring programs at its Downstream facilities, including refineries and the Lloydminster Upgrader. Husky has several inactive facilities ranging from former refineries to retail locations. Management and remediation plans are prepared for these sites based on current and future land use.

As part of the Company's review of proposed regulations that may affect its business and operations, the Company may, from time to time, prepare an internal analysis of the possible or expected impact of new regulations, which are subject to various uncertainties. It is not possible to predict with certainty the amount of additional investment in new or existing facilities required in the future for environmental protection or to address regulatory compliance requirements, such as reporting. Costs associated with levy payments for emerging climate change regulations may be significant. See "Risk Factors – Climate Change Regulation" for a description of the impact that climate change regulations may have on the Company.

INDUSTRY OVERVIEW

The operations of the oil and gas industry are governed by a number of laws and regulations mandated by multiple levels of government and regulatory authorities in Canada, the U.S. and other foreign jurisdictions. These laws and regulations, along with global economic conditions, have shaped the developing trends of the industry. The following discussion summarizes the trends, legislation and regulations that the Company believes have the most significant impact on the short and long-term operations of the oil and gas industry.

Crude Oil and Natural Gas Production

During 2017, certain members of the Organization of Petroleum Exporting Countries ("OPEC") and some key non-OPEC members voluntarily reduced production, which led to the increase in the global crude oil benchmarks. 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.

OPEC and non-OPEC members agreed on November 30, 2017 to extend the production cuts through the end of 2018 in an effort to reduce global oil inventories. U.S. crude oil production averaged an estimated 9.3 mmbbls/day in 2017 and is forecasted to average 10.3 mmbbls/day in 2018, which would mark the highest annual average production in U.S. history, surpassing the previous record of 9.6 mmbbls/day set in 1970.(1)

In Canada, the Western Canadian crude oil supply is forecasted to increase in the long term. In the Canadian Association of Petroleum Producers' ("CAPP") June 2017 publication, production in Canada was forecasted to increase from 3.9 mmbbls/day in 2016 to 5.4 mmbbls/day in 2030. The majority of production growth in Canada continues to be expected from the oil sands.(2)

Total U.S. natural gas production increased by approximately one percent in 2017 compared to 2016 due to improved economics related to expanded pipeline capacity in the U.S.(1)

(1) *"Short-Term Energy Outlook",January 2018, U.S. Energy Information Administration*
(2) *"Crude Oil Forecast, Markets and Transportation",June 2017, Canadian Association of Petroleum Producers*

Commodity Pricing

Crude oil and natural gas producers negotiate purchase and sale contracts directly with respective buyers and these contracts are typically based on the prevailing market price of the commodity. The market price for crude oil is determined largely by global factors, and the contract price considers oil quality, transportation and other terms of the agreement. The price for natural gas in Canada is determined primarily by North America fundamentals because virtually all natural gas production in North America is consumed by North American customers, predominantly in the U.S. Commodity prices are based on supply and demand which may fluctuate due to market uncertainty and other factors beyond the control of entities operating in the industry.

Global crude oil benchmarks strengthened in 2017 primarily due to the factors discussed under "Industry Overview – Crude Oil and Natural Gas Production". The price of West Texas Intermediate averaged US$50.95/bbl in 2017 compared to US$43.32/bbl in 2016. The price of Brent averaged US$54.28/bbl in 2017 compared to US$43.69/bbl in 2016.

Market Access

Existing pipelines used for exporting crude oil from Western Canada are currently at or near capacity. The nameplate design capacity is 4.0 mmbbls/day. However, the estimated available capacity for Canadian crude oil exiting Western Canada on the major pipeline system is only 3.3 mmbbls/day after operational downtime, downstream constraints and the capacity allocated to refined petroleum products.(1)

Without any new pipeline projects proposed, rail transportation will likely have to significantly increase in order to transport growing supplies. At June 2017, the proposed pipeline projects Enbridge Line 3, Kinder Morgan's Trans Mountain Expansion, TransCanada's Keystone XL and TransCanada's Energy East Pipeline would have been able to provide additional pipeline capacity of 2.9 mmbbls/day. (1)

On October 5, 2017, TransCanada Corporation announced the termination of the Energy East Pipeline project, which would have carried more than 1.0 mmbbls/day of oil from Alberta and Saskatchewan to be refined at or exported from facilities in New Brunswick and Québec.

(1) "Crude Oil Forecast, Markets and Transportation", June 2017, Canadian Association of Petroleum Producers.

Royalties, Incentives and Income Taxes

Canada

The amount of royalties payable on production from privately owned lands is negotiated between the mineral freehold owner and the lessee, and this production may also be subject to certain provincial taxes and royalties. Royalty rates for production from Crown lands are determined by provincial governments. When setting royalty rates, commodity prices, levels of production and operating and capital costs are considered. Royalties payable are generally calculated as a percentage of the value of gross production and generally depend on prescribed reference prices, well productivity, geographical location, field discovery date, method of recovery, depth of well and the type or quality of the petroleum product produced. Other royalties and royalty-like interests are, from time to time, carved out of the owner's working interest through non-public transactions. These are often referred to as overriding royalties, gross overriding royalties, net profits interests or net carried interests.

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.

The Canadian federal corporate income tax rate was 15 percent in 2017 and 2016. Provincial rates ranged between 11 percent and 16 percent in both 2017 and 2016.

Other Jurisdictions

Royalty rates in Asia Pacific averaged six percent in both 2017 and 2016.

Operations in the U.S are subject to the U.S. federal tax rate of 35 percent and various state-level taxes. Effective January 1, 2018, the U.S. federal corporate tax rate will be reduced from 35 percent to 21 percent. Operations in China are subject to the Chinese tax rate of 25 percent. Operations in Indonesia are subject to tax at a rate of 40 percent as governed by each project's PSC.

Land Tenure Regulation

In Canada, rights to natural resources are largely owned by the provincial and federal governments. Rights are granted to explore for and produce oil and natural gas subject to shared jurisdiction agreements, ELs, SDLs and production licences, leases, permits and provincial legislation which may include contingencies such as obligations to perform work or make payments.

For international jurisdictions, rights to natural resources are largely owned by national governments that grant rights in forms such as ELs and permits, production licences and PSCs. Companies in the oil and gas industry are subject to ongoing compliance with the regulatory requirements established by the relevant country for the right to explore, develop and produce petroleum and natural gas in that particular jurisdiction.

Environmental Regulations

General

Oil and natural gas operations are subject to environmental regulation pursuant to a variety of federal, provincial, state and local laws and regulations, as well as international conventions (collectively, "environmental regulations").

Environmental regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment, including emissions of GHGs. Environmental regulations also require that wells, facilities and other properties associated with Husky's operations be constructed, operated, maintained, abandoned and reclaimed in compliance with pertinent regulatory requirements. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments.

Some examples of potential areas for new or enhanced environmental regulation include:

- conventional air pollutant and GHG emission regulations and mandatory reductions in jurisdictions where the Company has operations.
- increased restrictions on freshwater licensing.
- enhanced groundwater and surface water monitoring.
- enhanced water discharge criteria.
- increased restrictions on waste water disposal.
- enhanced water recycle criteria.
- enhanced water crossing monitoring and reporting requirements.
- enhanced requirements for environmental assessment.
- wetland compensation.
- calculation and regulation of carbon intensity of fuels, including transportation fuels.
- fuel reformulation and substitution to support reduced GHG emissions.
- managing air pollutant emissions at equipment and facility levels with the general goal of ensuring compliance with increasingly more stringent ambient air quality standards.
- potential for restrictive operating policies on development in areas of particular value to species at risk.
- feedstock and product transportation by rail, pipeline and roadway.
- pipeline integrity management.
- reclamation.
- hydraulic fracturing.
- land use.

Water

Numerous regulations are imposed on Husky's operations with the general goal of ensuring surface water and fresh groundwater are protected. Guidelines dictate aspects including:

- well, pipeline, and facility offsets from fresh surface water bodies and domestic water wells.
- drilling fluids, well construction materials and methods to ensure isolation of fresh groundwater aquifers from resource exploration, extraction and disposal activities.
- baseline domestic water well testing.
- downhole offsets for completions operations, ensuring isolation from fresh groundwater aquifers, with specific risk mitigation expectations for hydraulic fracturing.
- monitoring of fresh groundwater aquifers and wetlands at major operating facilities.
- monitoring of assets that cross fish bearing streams ensuring passage is unrestricted.
- water discharge criteria for onshore and offshore facilities.
- fluid transport, handling and storage.
- water recycling aiming to reduce water withdrawals from freshwater sources.

Water withdrawals, in particular freshwater withdrawals, are regulated in jurisdictions in which Husky has operations with the general goal of ensuring that surface and groundwater supplies are not negatively impacted. Husky has reporting requirements relating to most licensed water withdrawals. Guidelines dictate water source selection and management. Water withdrawals are further governed by local watershed and/or industry water management plans.

Husky recognizes the importance of water security to the success of its operations and engages in dialogue on proposed regulatory changes, both directly and through industry associations, with the general goal of ensuring the Company's interests are recognized. Husky believes it is sufficiently prepared to fully comply when new water regulations come into force. Husky has a Corporate Water Standard that mandates Water Risk Assessments and Water Management Plans for its facilities, which include consideration of regulatory risks. Water Risk Assessments consider both known proposed water regulations and possible future regulations (not currently proposed). Husky has realized financial impacts due to regulation changes; proposed and future regulation changes could also have financial impacts. The purpose of the Water Risk Assessments is to try to identify and mitigate these risks.

Migratory Birds

Canada's oil and gas industry may affect migratory birds and bird habitat through land disturbance activities and operating practices (e.g., sludge ponds). Industry activities risk contravening the Migratory Bird Convention Act (Canada) ("MBCA") and supporting legislation that prohibits the disturbance and destruction of migratory birds, their eggs and/or nests. In 2016, the Environmental Enforcement Act (Canada) introduced a new fine regime that increased maximum fines up to $6 million, with all subsequent fines doubling, for corporations that are convicted under the MBCA. The Company has improved the protection of migratory birds through development of a Standard for Pre-Construction Migratory Bird Incidental Take Mitigation, supported by both web-based and field-based training.

Air and Climate Change

General

The current regulatory environment related to air emissions and climate policy is dynamic. The impacts of emerging policy remain largely uncertain as various jurisdictions define and implement new regulations. Husky engages in consultations for the design of proposed regulations and supports efforts to harmonize regulations across jurisdictions, both directly with regulators and through industry associations. Risk associated with these regulations is discussed under "Risk Factors".

Husky operates in many jurisdictions that regulate or have proposed to regulate air pollutants including GHG emissions. Air regulations include:

- absolute and intensity based emissions limits.
- market based frameworks.
- equipment and/or facility level emission performance standards.
- other regulatory measures including low carbon fuel and renewable fuel standards.

In 2016, Husky's gross Scope 1 emissions were 11,242,000 tCO_2e. Scope 2 emissions in that year were 2,128,000 tCO_2e. The Company uses a GHG management framework to guide the process of integrating climate change into its business strategy. Elements of the GHG management framework that inform corporate business strategy include GHG inventory and quantification, GHG reporting and verification, an emissions reduction strategy, and a regulatory policy system.

In addition to climate policy risk, the industry faces physical risks attributable to a changing climate. Husky operates in some of the harshest environments in the world, including offshore NL. Climate change is expected to increase the frequency of severe weather conditions including winds, flooding and variable temperatures, which are contributing to the melting of northern ice and increased iceberg activity. The Company has in place a number of policies to protect people, equipment and the environment in the event of extreme weather conditions and adverse ice conditions.

Husky is managing physical risk through engineering for 1:100 year weather events. The Company's Atlantic business 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.

International Climate Change Agreements

Canada has submitted a Nationally Determined Contribution to reduce GHG emissions by 30 percent below 2005 levels by 2030 as part of the Paris Agreement at the United Nations Framework Convention on Climate Change Conference of the Parties held in Paris, France in December 2015. There is a commitment to review and increase pledges every five years under the Paris Agreement. Canada approved the Paris Agreement in October 2016. On August 4, 2017, the U.S. submitted formal notice of intention to withdraw from the Paris Agreement; however, under the terms of the Paris Agreement, the U.S. will remain a party until approximately August 2020.

At the Conference of the Parties held in Bonn, Germany in November 2017, Canada, Mexico and a coalition of 15 U.S. State Governors signed a Joint Declaration to strengthen climate action. The declaration forms a new North American Climate Leadership Dialogue to address topics such as clean transportation, carbon pricing initiatives and reducing short-lived climate pollutants. In addition, an increasing number of national and subnational jurisdictions are signatories of the U.K. and Canada's alliance to phase-out coal in their energy systems.

These international agreements can be expected to significantly influence climate change-related regulations and initiatives in both Canada and the U.S., which will impact Husky's operations. See "Risk Factors".

Canadian Federal Regulations

The Canadian federal government has begun addressing emissions from specific sectors of the economy, including working closely with the U.S. government to establish common North American vehicle emissions standards, as well as performance standards for thermal electricity generation. Canada has adopted renewable fuels regulations, requiring fuel producers and importers to have an average of at least five percent of their gasoline supply come from renewable sources (such as ethanol) and to have an average of at least two percent of their diesel supply come from renewable sources (such as bio-diesel).

In 2012, the Canadian Council of Ministers of the Environment agreed to implement a new Air Quality Management System ("AQMS") to protect human health and the environment through the continuous improvement of air quality in Canada. AQMS includes three main components: Canadian Ambient Air Quality Standards ("CAAQS"); Base-Level Industrial Emissions Requirements ("BLIERs"); and the management of air quality through local air zones and regional airsheds.

CAAQS are the AQMS driver and set the bar for air quality management across the country. New standards for ozone and fine particulate matter for 2015 and 2020 were published in 2013. New CAAQS for sulphur dioxide for 2020 and 2025 were announced in 2016, and new CAAQS for nitrogen dioxide for 2020 and 2025 were published in November 2017.

Under the BLIERs, three regulations and a guideline were developed within the AQMS. The first tranche of the Multi-Sector Air Pollutants Regulations was published in June 2016. These regulations have included three BLIERs developed under AQMS for the cement sector, reciprocating spark-ignited natural gas engines and non-utility boilers and heaters in industrial sectors. An emissions guideline under the Canadian Environmental Protection Act for stationary gas turbines was published in November 2017. Other sectors and pollutants will be added to the regulations in the future.

The BLIERs pertaining to nitrogen oxide ("NOx") emissions from boilers and heaters and NOx emissions from reciprocating engines in industrial facilities are applicable to the Company's Canadian Upstream and Downstream oil and gas facilities, with the exception of the Prince George Refinery since a sector-specific Refining BLIER will be developed separately for petroleum refineries. The Boiler & Heater BLIER and Reciprocating Engine BLIER have introduced performance, design and monitoring standards for both existing and new equipment units, whereas the Stationary Gas Turbine BLIER has only introduced performance and design standards for new equipment.

Within the mandate of the Pan-Canadian Framework on Clean Growth and Climate Change, in May 2017 the federal government of Canada released a technical paper on the federal Carbon Pricing Backstop introducing two key elements: a carbon levy applied to fossil fuels ($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. Further details of the output-based pricing system were announced on January 15, 2018. Provinces may either "opt in"to the federal system or put in place their own system, provided that system meets or exceeds the national floor price either through a direct price on carbon or a cap-and-trade system. Provinces have until March 30, 2018, to elect to "opt in"or September 1, 2018, to outline their provincial system. Provinces that have either opted in or whose systems are not deemed equivalent to the federal system will be subject to the federal system starting January 1, 2019.

A federal Clean Fuel Standard Discussion Paper was also released in February 2017. The Clean Fuel Standard will be developed to achieve 30 megatonnes of annual reductions in GHG emissions by 2030 through requiring reductions in fuel carbon intensities based on a life-cycle analysis and will go beyond transportation fuels to include fuels used in industry and buildings. In December 2017, the clean fuel standard regulatory framework was published. Proposed regulations are expected to be published in late 2018, with final regulations published in 2019. Consultations on the federal Clean Fuel Standard are ongoing.

The Government of Canada is committed to reducing methane emissions from the oil and gas sector by 40 percent to 45 percent below 2012 levels by 2025. Draft methane reduction regulations for the Upstream oil and gas industry were published on May 27, 2017. Sources addressed by the draft regulations include venting from wells and batteries (including associated gas at oil facilities), storage tanks, pneumatic devices, well completions, compressors and fugitive equipment leaks. Draft regulations apply to new and existing sources, with the first requirements coming into force as early as 2020, and the remaining requirements coming into force by 2023.

Environment and Climate Change Canada is expected to negotiate equivalency agreements with interested provinces and territories to enable these jurisdictions to be front-line regulators where they have legally binding regimes that produce equal or better environmental outcomes.

Canadian Provincial Greenhouse Gas Regulations

In 2015, Alberta announced a major shift in its climate regulations through its Climate Leadership Plan. It includes four key areas in which the Government of Alberta is moving forward:

- Phasing out emissions from coal-generated electricity and developing more renewable energy.
- Implementing a new carbon price on emissions of GHGs.
- A legislated oil sands emission limit.
- Employing a new methane emission reduction plan.

Existing regulations provide that large final emitting facilities ("LFEs") (facilities that emit over 100,000 tCO_2e per year) were required to reduce their emissions intensity by 20 percent by January 1, 2017. The price of the carbon levy (payment of which may be used to make up for any shortfall in actual emissions intensity reductions) increased from $15/$tCO_2e$ to $20/$tCO_2e$ for 2016 and $30/$tCO_2e$ for 2017 for LFEs. As of January 1, 2018, LFEs will fall under the Carbon Competitiveness Incentives regulation that will employ output-based allocations to benchmark facilities against peers.

As of January 1, 2018, Alberta increased its broad-based carbon levy to $30 per tonne. The government has signaled an intention to increase the price in real terms periodically after 2018. Emissions from the combustion of produced fuel at conventional oil and gas facilities emitting less than 100,000 tCO_2e per year will be exempt until January 1, 2023, to allow time for these facilities to reduce methane emissions under provincial and federal methane regulations. Finally, total emissions from the oil sands will be capped at a maximum of 100 megatonnes in any year, with provisions for cogeneration and new upgrading capacity. The details of how this emissions limit will be implemented have not been finalized.

The Alberta Energy Regulator ("AER") is working collaboratively to develop and implement a regulatory framework that achieves the Government of Alberta's methane emissions reduction outcome of 45 percent by 2025. Alberta has announced that it intends to reduce methane emissions from oil and gas operations by 45 percent by 2025 using the following approaches:

- Applying new emissions design standards to new Alberta facilities.
- Improving measurement and reporting of methane emissions, as well as leak detection and repair requirements.
- Developing a joint initiative on methane reduction and verification for existing facilities and backstopping this with regulated standards that take effect in 2020, with the general goal of ensuring the 2025 target is met.

In December 2017, the Government of Saskatchewan released "Prairie Resilience: A Made-In-Saskatchewan Climate Change Strategy." The Strategy includes a commitment to implement sector-specific output-based performance standards on facilities emitting more than 25,000 tCO_2e per year. Saskatchewan does not plan to implement an economy-wide carbon tax. In such a case the federal government has committed to implementing such a tax (the federal"backstop") and returning revenues to the provincial government. Consultation on implementation of both the Strategy and the federal "backstop" is ongoing.

In British Columbia, regulations established in 2008 target a provincial reduction in GHG emissions of at least 33 percent below 2007 levels by 2020 and 80 percent below 2007 levels by 2050.

British Columbia currently has a $30 per tonne carbon tax. Additionally, British Columbia has a Renewable and Low Carbon Fuel Requirements Regulation in place that requires a reduction in the allowable carbon intensities of fuels, with penalties applied for intensities that do not meet targets.

The British Columbia government released its Climate Leadership Plan in August 2016. The 21 actions are targeted across major sectors of the economy, including annual reductions of up to five million tCO_2e by 2050 in the oil and gas sector through a focus on methane emissions, carbon capture and storage as well as electrification. The British Columbia government has also announced plans to increase the provincial price on carbon by $5 per tonne annually (starting in April 2018) to $50 per tonne in 2021.

In October 2017, Manitoba published "A Made-in-Manitoba Climate and Green Plan"that includes 16 keystones for priority action that "will support Manitoba's economy and sustain the environment for future generations".The plan sets out a flat carbon price of $25 per tonne beginning in 2018. The Manitoba carbon tax will not rise, and a full review of the carbon pricing plan will take place in 2022. Large industrial emitters will be able to reduce their emissions while having their competitiveness concerns addressed through an output-based pricing system of performance standards, offsets and credit trading. Consultation on the details of implementation is ongoing.

The Ontario cap and trade regulation took effect on July 1, 2016, and included detailed requirements for businesses participating in the program, including: GHG emission caps, entities covered by the program, compliance, auction and sale of allowances and distribution of allowances. The program also regulates end-use combustion of transportation fuels. The linkage of the cap and trade programs of Ontario, Québec and California was announced in September 2017. The official linkage of the Ontario—Western Climate Initiative ("WCI") program will be effective on January 1, 2018, creating the world's second largest carbon market after the European Union Emissions Trading System.

On November 9, 2016, the Government of NL released "The Way Forward: A Vision for Sustainability and Growth in NL,"indicating it is committed to making progress on the issue of climate change. The NL government is working toward reducing provincial emissions of GHGs to 10 percent below 1990 levels, by 2020. Consultation with the government on the details of implementation is ongoing. 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 the Province of NL jurisdiction to regulate offshore GHG emissions.

U.S. Greenhouse Gas Regulations

The U.S. does not have federal legislation establishing targets for the reduction of or limits on the emission of GHGs. However, the federal Environmental Protection Agency ("EPA") has and may continue to promulgate regulations concerning the reporting and control of GHG emissions. Since 2010, the EPA's Greenhouse Gas Reporting Program ("GHGRP") requires any facility releasing more than 25,000 tCO_2e emissions per year to report those emissions on an annual basis. In addition to reporting direct CO_2e emissions, the GHGRP requires refineries to estimate the CO_2e emissions from the potential subsequent combustion of the refinery's products.

In May 2010, the EPA finalized the Greenhouse Gas Tailoring Rule. This rule "tailored" the Clean Air Act by phasing in permitting requirements for GHG emissions, including Best Available Control Technology ("BACT") requirements for new and modified sources of air emissions emitting more than a threshold quantity of GHGs. In June 2014, the U.S. Supreme Court issued its opinion in Utility Air Regulatory Group v. EPA. The Court invalidated portions of the Tailoring Rule but upheld the EPA's authority to require BACT for GHG emissions associated with sources that must obtain Prevention of Significant Deterioration permits based on their non-GHG emissions. Based on the Court's opinion, it is possible that the EPA will amend the Tailoring Rule in a way that imposes additional GHG requirements on industrial facilities.

The EPA has not yet issued proposed or final GHG emissions standards for new or existing refineries but could do so in the future. These and other EPA regulations regarding GHG emissions are subject to judicial challenges and could be modified by regulatory actions or new legislation.

U.S. Renewable Fuel Standard

The U.S. created its Renewable Fuel Standard ("RFS") program with the stated intention of reducing GHG emissions and expanding the renewable fuels sector, while reducing U.S. reliance on imported oil. The RFS program was authorized under the Energy Policy Act of 2005 and expanded under the Energy Independence and Security Act of 2007. The EPA implements the RFS program in consultation with the U.S. Department of Agriculture and Department of Energy.

The RFS program is a national policy that requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel. Obligated parties under the RFS program are refiners or importers of gasoline or diesel fuel. Compliance is achieved by blending renewable fuels into transportation fuel or by obtaining credits, called Renewable Identification Numbers ("RINs") to meet an EPA-specified Renewable Volume Obligation ("RVO"). The RVOs set in November 2017 for calendar year 2018 were similar to those for 2017. It is possible that advocacy groups will challenge the RVOs with the goal of forcing the EPA to establish more stringent RVOs.

The U.S. EPA calculates and establishes RVOs every year through rulemaking. The standards are converted into a percentage, and obligated parties must demonstrate compliance annually.

Abandonment Liability

Over a three-year period, the AER phased in parameter updates to the licencee abandonment liability program. These changes were fully implemented in May 2015 under Directive 006: Licencee Liability Rating Program and Licence Transfer Process and effected important changes to the Licencee Liability Rating Program. The Licencee Liability Rating Program is designed to prevent Alberta taxpayers from incurring costs to suspend, abandon, remediate and reclaim a well, facility or pipeline. Under the Licencee Liability Rating Program, each licencee is assigned a Liability Management Rating. The Liability Management Rating is the ratio of a licencee's eligible deemed assets under the Licencee Liability Rating Program, the Large Facility Liability Management Program and the Oilfield Waste Liability Program to its deemed liabilities in these programs. The Liability Management Rating assessment is designed to assess a licencee's ability to address its suspension, abandonment, remediation and reclamation liabilities. This assessment is conducted monthly and on receipt of a licence transfer application in which the licencee is the transferor or transferee.

If a licencee's deemed liabilities exceed its deemed assets, the licencee is required to post a security deposit with the AER to make up the shortfall. If a licencee fails to post security, if required, then the AER may take a number of steps to enforce these provisions, which include non-compliance fees, partial or full suspension of operations, suspension and/or cancellation of a permit, licence or approval and prevention of the transfer of licences held by licencees that do not meet the new requirements.

As a result of the Redwater Energy Corp. ("Redwater") bankruptcy court ruling released in May 2016, whereby the court found that receivers and trustees of AER licencees may selectively disclaim unprofitable assets (and their associated abandonment and reclamation obligations) under section 14.06 of the Bankruptcy and Insolvency Act (Canada), the AER and the Orphan Well Association are actively working on appropriate regulatory measures to mitigate the liability impact of licencee's abandonment, reclamation and remediation obligations from falling back to the industry.

Consequently, as of June 2016 a condition of transferring existing AER licences, approvals and permits, will require transferees to demonstrate that they have a liability management ratio ("LMR") of 2.0 or higher immediately following the transfer.The AER recognizes this is a significant change, but they have observed that purchasers with an LMR of 1.0 or below have had significant difficulty meeting their liabilities after the transfer. If the transfer of the licencee does not improve the purchaser's LMR to 2.0 (or higher), the purchaser can post a security deposit, address existing abandonment obligations or transfer additional assets.

Similar to the AER, the Government of Saskatchewan has established an LMR rating of 1.0 as its threshold for providing a deposit. If a licencee's LMR is less than 1.0, meaning the liability is greater than the deemed assets, that licencee will be required to submit a deposit to the Saskatchewan Ministry of the Economy ("ECON") for the amount of the difference.

In response to the Redwater ruling, all licence transfer applications in Saskatchewan will be reviewed in detail, and ECON will consider relevant factors in calculating transfer deposit requirements. In addition to increased deposit requirements, ECON may incorporate additional conditions with licence transfer approvals which may impact the decision to proceed with certain transactions.

The Government of Saskatchewan intervened in the Alberta Court proceedings regarding Redwater's bankruptcy with the general goal of ensuring their views are fully considered by the courts. The Saskatchewan Ministry of Justice has indicated opposition to any attempt by a receiver in Saskatchewan to renounce uneconomic oil and gas assets which are subject to the LMR program in Saskatchewan. The Saskatchewan ministry has stated that licence transfer applications in Saskatchewan will be considered non-routine as the Saskatchewan ministry will not be strictly relying on the standard LMR calculations in evaluating deposit requirements.

Hydraulic Fracturing

Hydraulic fracturing is a method of increasing well production by injecting fluid under high pressure down a well to crack the hydrocarbon bearing rock. In the case of water-based fractures, the fluid typically consists of water, sand, and a relatively small amount of chemicals. This mixture flows into the cracks where the sand remains to keep the cracks open and enable natural gas or liquids to be recovered. Fracturing is designed so that the fracturing fluids can be produced back to the surface through the wellbore and are stored for reuse or future disposal in accordance with provincial regulations. The wells are designed and installed to provide multiple barriers protecting fresh groundwater aquifers from the fracturing process.

The Government of Canada manages use of chemicals through its Chemical Management Plan and New Substances Program. Some provinces require the details of fracturing fluids to be submitted to regulators. In Alberta, the AER requires that all fracturing operations submit reports regarding the quantity of fluids and additives. For Alberta and British Columbia, the website www.FracFocus.ca provides the public with access to individual well summaries of the fluids and chemicals reported.

In response to concerns that hydraulic fracturing may induce seismic events, the AER has imposed requirements for seismic monitoring, mitigation response plans and reporting in select areas of the province.

Inter-wellbore communication during hydraulic fracturing operations is the transfer of pressure from the wellbore being stimulated to an adjacent offset well. This event is dependent on a number of factors such as distance between wells, type of fluid used and whether an energizer is being used during operations. AER Directive 83 and IRP 24 provide rules and guidelines addressing this concern.

Land Use

In 2012, the Government of Alberta approved the Lower Athabasca Regional Plan ("LARP"), which covers the lower Athabasca region and includes Husky's oil sands assets and major projects in the province. The LARP was developed to consider cumulative effects within the region using formal management frameworks for: Air Quality, Surface Water Quality and Quantity, Groundwater Management and Biodiversity.

The use of each framework establishes approaches with the general goal of ensuring trends are identified and assessed, regional limits are not exceeded and air, water and biodiversity remain healthy for the region's residents and ecosystems during oil sands development. To date, the Biodiversity Framework under LARP has not been finalized.

The South Saskatchewan Regional Plan was approved by the Government of Alberta in 2014, and was subsequently amended in 2017, and covers the southern portion of Alberta, including some Husky Western Canada assets. The plan details Alberta's long term commitment to conservation, protection of watersheds, sustaining biodiversity and sensitive habitats.

Industry Collaboration Initiatives

Husky participates in a number of industry associations and sustainability groups to better understand environmental, safety and social issues while benefitting from, and contributing to, industry innovation and good management practices.

Through Husky's membership in Canada's upstream industry association, CAPP,and the Canadian Fuels Association, which represents Canada's refining and transportation fuels industry, and the American Fuels and Petrochemical Manufacturers which represents the U.S. refining and petrochemicals industry, the Company enhances its ability to identify and address potential policy and regulatory risks to its business and participates in advocacy related activity to reduce those risks. Husky participates on the CAPP Board of Governors, as well as various Executive Policy Groups and working level groups and committees that focus on areas of policy or regulation that have been identified as areas of interest or impact to Husky's business. Similarly, Husky participates in the Canadian Fuels Association Board of Directors, Strategy & Planning Group, as well as various resource groups and national committees.

Husky is a member of IPIECA, the global oil and gas industry association for environmental and social issues, and is participating in its Water Task Force and Climate Change Working Group as well as other topic focused groups. The Company is also a member of Oil Spill Response Limited, an international industry-owned cooperative whose objective is to respond effectively to oil spills wherever in the world they may occur. In 2016, Husky joined the IETA and is participating in its Canadian Working Group. The IETA's objective is to build international policy and market frameworks for reducing GHGs at the lowest cost.

Husky also collaborates on water and carbon management and risk mitigation through involvement in industry initiatives and committees. As a member of the joint-industry Water Technology Development Centre and other joint-industry projects, Husky is committed to developing technologies that will reduce water and energy use for in-situ thermal bitumen operations.

Husky pursues memberships with the following sustainability groups and industry associations: Alberta Industrial Fire Protection Association; Allen County Environmental Citizen's Advisory Committee; American Fuel and Petrochemical Manufacturers; Beaver River Watershed Alliance; Calgary Region Airshed Zone; Canadian Association of Petroleum Producers; Canadian Brownfields Network; Canadian Fuels Association; Canadian Land Reclamation Association; Canada's Oil Sands Innovation Alliance Monitoring Subcommittee; China Offshore Environmental Services; China Offshore Oil Operation Safety Office; China's State Oceanic Administration; China's Marine Safety Administration; Clearwater Mutual Aid CO-OP; Clearwater Trails Initiative; Conference Board of Canada—Council on Emergency Management; Devonian Aquifer Working Group and Monitoring Priority Area - Canada's Oil Sands Innovation Alliance joint industry project; Earth Rangers; Eastern Canada Response Corporation; Edson Mutual Aid Committee; Emergency Response Assistance Canada; Environmental Services Association of Alberta; Environmental Studies Research Funds; Faster Forests (Canada's Oil Sands Innovation Alliance); Foothills Research Institute - Grizzly Bear Program; Foothills Restoration Forum -Southwest Alberta Sustainable Community Initiative; Grasslands Air Zone; Hardisty Mutual Aid Plan; International Emissions Trading Association; Indonesian Petroleum Association; International Oil & Gas Producers Association; International Petroleum Industry Environmental Conservation Association; Joint Canada-Alberta Plan for Oil Sands Monitoring; Lakeland Industry and Community Association; Land Spill Emergency Program; Lloydminster Emergency Preparedness Stakeholder Group; Mackenzie Delta Spill Response Corporation; Marine Pollution Control; Mutual Aid Alberta; North Saskatchewan Watershed Alliance; Ohio Chemistry Trade Council; Oil Spill Response Limited; One Ocean; Orphan Well Association; Ottawa River Coalition; Parkland Airshed Management Zone; Petroleum Research Newfoundland and Labrador; Petroleum Technology Alliance Canada; Plains CO2 Reduction Partnership; Prince George Air Improvement Roundtable; Saskatchewan Petroleum Industry Government Environmental Committee; Saskatchewan Prairie Conservation Action Plan; Southeast Saskatchewan Airshed Association; Transportation Community Awareness and Emergency Response; Upstream Saskatchewan Spill Response Co-op Area 2, 3 & 4 Spill Response Cooperatives; Water Technology Development Centre - Canada's Oil Sands Innovation Alliance joint industry project; Western Canada Marine Response Corporation; Western Canadian Spill Services; Western Yellowhead Air Management Zone; and Wood Buffalo Environmental Association.

Husky's Sustainability Commitment

Husky's sustainability is a key pillar of the financial well-being of the Company. While sustainability begins with a strong financial foundation, success is directly linked to how the Company conducts its business, whether it is by improving safety, taking steps to protect the environment or delivering lasting benefits to the communities. More information can be found in the Husky Energy Community Report 2016, which can be accessed at www.huskyenergy.com.

RISK FACTORS

The following summarizes what Husky believes to be the most significant risks relating to its operations which should be considered when purchasing securities of Husky. Husky 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 risk matrix and associated mitigation strategies are reviewed quarterly by senior management and the Audit Committee, and annually by the Board of Directors.

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 HOIMS, 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 this AIF 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. See "Industry Overview – Environmental Regulations".

Climate Change Regulation

Climate change regulations may become more onerous over time as governments implement policies to further reduce 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 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. See "Industry Overview – Air and Climate Change – Canadian Provincial Greenhouse Gas Regulations".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 CO_2e each year. This would include Husky'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. See "Industry Overview – Air and Climate Change – Canadian Provincial Greenhouse Gas Regulations".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 Husky's Prince George Refinery. Additionally, future regulations in support of British Columbia's commitment under its Climate Leadership Plan are uncertain. See "Industry Overview – Air and Climate Change – Canadian Provincial Greenhouse Gas Regulations".

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 Husky's Minnedosa ethanol plant in Manitoba. See "Industry Overview – Air and Climate Change – Canadian Provincial Greenhouse Gas Regulations".

Climate change regulations for the NL offshore are currently being developed as part of a consultation process involving the four offshore operators via 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 EPA's 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. RFS program, through the EPA-specified RVO, requires refiners to add annually increasing amounts of renewable fuels to their petroleum products or to purchase RINs in lieu of such blending. See "Industry Overview – Air and Climate Change – U.S. Renewable Fuels Standard". 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.

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.

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.

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.

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.

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.

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 Attraction and Retention

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.

HUSKY EMPLOYEES

The number of Husky's permanent employees was as follows:

	As at December 31,		
	2017	2016	2015
Number of permanent employees	**5,152**	5,150	5,552

DIVIDENDS

Dividend Amounts

The following table shows the aggregate amount of the dividends declared payable per share in respect of its last three years ended December 31, for the Company's common shares, Series 1 Preferred Shares, Series 2 Preferred Shares, Series 3 Preferred Shares, Series 5 Preferred Shares and Series 7 Preferred Shares:

	2017	2016	2015
Dividends per Common Share	**$0.075**	$ —	$0.900
Dividends per Series 1 Preferred Share	**$ 0.60**	$0.73	$ 1.11
Dividends per Series 2 Preferred Share	**$ 0.57**	$0.42	$ —
Dividends per Series 3 Preferred Share	**$ 1.13**	$1.13	$ 1.19
Dividends per Series 5 Preferred Share	**$ 1.13**	$1.13	$ 0.90
Dividends per Series 7 Preferred Share	**$ 1.15**	$1.15	$ 0.62

Dividend Policy and Restrictions

The declaration and payment of dividends are at the discretion of the Board of Directors, which will consider earnings, commodity price outlook, future capital requirements and financial condition of Husky, the satisfaction of the applicable solvency test in Husky's governing corporate statute, the Business Corporations Act (Alberta) and other relevant factors.

Common Share Dividends

Shareholders have the ability to receive dividends in common shares or in cash. Quarterly dividends are declared in an amount expressed in dollars per common share and can be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume weighted average trading price of the common shares is calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares. With falling oil prices in 2015, the Board of Directors introduced in the third quarter of 2015 a stock dividend in lieu of cash. This dividend was paid on January 11, 2016. With the persistent downward pressure on oil prices and the extended "lower for longer" outlook, in the fourth quarter of 2015, the Board of Directors suspended the Company's quarterly dividend on its common shares. There were no common share dividends declared in the year 2017 (year ended December 31, 2016 – nil).

The Company's dividend policy is reviewed on a regular basis and there can be no assurance that dividends will be declared or the amount of any future dividends.

On February 28, 2018, the Company declared dividends of $0.075 per common share, for the fourth quarter of 2017. The dividend will be payable on April 2, 2018 to shareholders of record at the close of business on March 20, 2018.

Series 1 Preferred Share Dividends

Holders of Series 1 Preferred Shares were entitled to receive a cumulative quarterly fixed dividend, payable on the last day of March, June, September and December in each year, of 4.45 percent annually for the initial period ending March 31, 2016, as and when declared by the Board of Directors. Thereafter, the dividend rate will be reset every five years at a rate equal to the five-year Government of Canada bond yield plus 1.73 percent. Holders of Series 1 Preferred Shares had the right, at their option, to convert their shares into Series 2 Preferred Shares, subject to certain conditions, on March 31, 2016. In the first quarter of 2016, Husky announced it did not intend to exercise its right to redeem the Series 1 Preferred Shares on March 31, 2016. As a result, the holders of the Series 1 Preferred Shares had the right to choose to retain any or all of their Series 1 Preferred Shares and continue to receive an annual fixed rate dividend paid quarterly, or convert, on a one-for-one basis, any or all of their Series 1 Preferred Shares into Series 2 Preferred Shares, and receive a floating rate quarterly dividend. Holders of Series 1 Preferred Shares who retained their shares will receive the new fixed rate quarterly dividend applicable to the Series 1 Preferred Shares of 2.404 percent for the five-year period commencing March 31, 2016 to, but excluding, March 31, 2021. Effective March 31, 2016, Husky had 10,435,932 Series 1 Preferred Shares issued and outstanding. Holders of the Series 1 Preferred Shares will have the opportunity to convert their shares again on March 31, 2021, and every five years thereafter as long as the shares remain outstanding.

Series 2 Preferred Share Dividends

Holders of the Series 2 Preferred Shares are entitled to receive a cumulative quarterly floating rate dividend, payable on the last day of March, June, September and December in each year, at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 1.73 percent as and when declared by the Board of Directors. Effective March 31, 2016, Husky Energy had 1,564,068 Series 2 Shares issued and outstanding. Holders of the Series 2 Shares will have the opportunity to convert their shares again on March 31, 2021, and every five years thereafter as long as the shares remain outstanding.

Series 3 Preferred Share Dividends

Holders of the Series 3 Shares are entitled to receive a cumulative quarterly fixed dividend, payable on the last day of March, June, September and December in each year, of 4.50 percent annually for the initial period ending December 31, 2019 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.13 percent. Holders of Series 3 Shares will have the right, at their option, to convert their shares into Series 4 Preferred Shares, subject to certain conditions, on December 31, 2019 and on December 31 every five years thereafter. Holders of the Series 4 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.13 percent.

Series 5 Preferred Share Dividends

Holders of the Series 5 Preferred Shares are entitled to receive a cumulative quarterly fixed dividend, payable on the last day of March, June, September and December in each year, of 4.50 percent annually for the initial period ending March 31, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.57 percent. Holders of Series 5 Preferred Shares will have the right, at their option, to convert their shares into Series 6 Preferred Shares, subject to certain conditions, on March 31, 2020 and on March 31 every five years thereafter. Holders of the Series 6 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.57 percent

Series 7 Preferred Share Dividends

Holders of the Series 7 Preferred Shares are entitled to receive a cumulative fixed dividend, payable on the last day of March, June, September and December in each year, of 4.60 percent annually for the initial period ending June 30, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.52 percent. Holders of the Series 7 Preferred Shares will have the right, at their option, to convert their shares into Series 8 Preferred Shares, subject to certain conditions, on June 30, 2020 and on June 30 every five years thereafter. Holders of the Series 8 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.52 percent.

DESCRIPTION OF CAPITAL STRUCTURE

Common Shares

Husky is authorized to issue an unlimited number of no par value common shares. The holders of common shares are entitled to receive notice of and attend all meetings of shareholders, except meetings at which only holders of a specified class or series of shares are entitled to vote, and are entitled to one vote per common share held. Holders of common shares are also entitled to receive dividends as declared by the Board of Directors on the common shares payable in whole or in part as a stock dividend in fully paid and non-assessable common shares or by the payment of cash. Holders are also entitled to receive the remaining property of Husky upon dissolution in equal rank with the holders of all other common shares.

If the Board of Directors declares a dividend on the common shares payable in whole or in part as a stock dividend, unless otherwise determined by the Board of Directors of Husky in respect of a particular dividend, the value of the common shares for purposes of each stock dividend declared by the Board of Directors of Husky shall be deemed to be the volume weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded, calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares.

In the event the stock dividend is to be issued pursuant to Husky's Stock Dividend Program, shareholders of record wishing to accept a payment of the stock dividend, and of future stock dividends declared by the Board of Directors in the form of common shares pursuant to Husky's Stock Dividend Program, are required to complete and deliver to Husky's transfer agent a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend. The Stock Dividend Confirmation Notice permits shareholders to confirm that they will accept common shares as payment of the dividend on all or a stated number of their common shares. A Stock Dividend Confirmation Notice will remain in effect for all stock dividends on the common shares to which it relates and which are held by the shareholder unless the shareholder delivers a revocation notice to Husky's transfer agent, in which case the Stock Dividend Confirmation Notice will not be effective for any dividends having a declaration date that is more than five business days following receipt of the revocation notice by Husky's transfer agent. In the event a shareholder fails to deliver a Stock Dividend Confirmation Notice at least five business days prior to the record date of a declared dividend, or delivers a Stock Dividend Confirmation Notice confirming that the holder of common shares accepts the common shares as payment of the dividend on some but not all of the holder's common shares, the dividend on common shares for which no Stock Dividend Confirmation Notice was delivered or the dividend on those of the holder's common shares in respect of which the holder did not deliver a Stock Dividend Confirmation Notice, will be paid in cash. See "Dividends – Dividend Policy and Restrictions – Common Share Dividends".

Preferred Shares

Husky is authorized to issue an unlimited number of no par value preferred shares. The preferred shares as a class have attached thereto the rights, privileges, restrictions and conditions set forth below.

The preferred shares may from time to time be issued in one or more series, and the Board of Directors may fix from time to time before such issue the number of preferred shares which is to comprise each series and the designation, rights, privileges, restrictions and conditions attached to each series of preferred shares including, without limiting the generality of the foregoing, any voting rights, the rate or amount of dividends or, the method of calculating dividends, the dates of payment thereof, the terms and conditions of redemption, purchase and conversion if any, and any sinking fund or other provision.

The preferred shares of each series shall, with respect to the payment of dividends and the distribution of assets or return of capital in the event of liquidation, dissolution or winding up of Husky, whether voluntary or involuntary, or any other return of capital or distribution of assets of Husky amongst its shareholders for the purpose of winding up its affairs, be entitled to preference over the common shares of Husky and over any other shares of Husky ranking by their terms junior to the preferred shares of that series. The preferred shares of any series may also be given such other preferences over the common shares of Husky and any other such preferred shares.

If any cumulative dividends or amounts payable on the return of capital in respect of a series of preferred shares are not paid in full, all series of preferred shares shall participate ratably in respect of accumulated dividends and return of capital.

In 2011, Husky issued 12 million Series 1 Preferred Shares and authorized the issuance of 12 million Series 2 Preferred Shares. In 2014, Husky issued 10 million Series 3 Preferred Shares and authorized the issuance of 10 million Series 4 Preferred Shares. In 2015, Husky issued 8 million Series 5 Preferred Shares and 6 million Series 7 Preferred Shares and authorized the issuance of 8 million Series 6 Preferred Shares and 6 million Series 8 Preferred Shares. See "Dividends – Dividend Policy and Restrictions – Series 1 Preferred Share Dividends" and "Dividends – Dividend Policy and Restrictions – Series 2 Preferred Share Dividends" and "Dividends – Dividend Policy and Restrictions – Series 3 Preferred Share Dividends" and "Dividends – Dividend Policy and Restrictions – Series 5 Preferred Share Dividends"and "Dividends – Dividend Policy and Restrictions – Series 7 Preferred Share Dividends". None of the issued preferred shares are entitled to vote, except in accordance with the provisions of the Business Corporations Act (Alberta).

Husky may, at its option, redeem all or any number of the then outstanding Series 1 Preferred Shares, subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 2 Preferred Shares, subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 3 Preferred Shares, subject to certain conditions, on December 31, 2019 and on December 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 5 Preferred Shares, subject to certain conditions, on March 31, 2020 and on March 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 7 Preferred Shares, subject to certain conditions, on June 30, 2020 and on June 30 every five years thereafter.

Liquidity Summary

Overview

The following information relating to Husky's credit ratings is provided as it relates to Husky's financing costs, liquidity and operations. Specifically, credit ratings affect Husky's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the Company's ability to engage in certain collateralized business activities on a cost effective basis depends on Husky's credit ratings. A reduction in the current rating on Husky's debt by one or more of its rating agencies, particularly a downgrade below investment grade ratings, or a negative change in Husky's ratings outlook could adversely affect Husky's cost of financing and its access to sources of liquidity and capital. In addition, changes in credit ratings may affect Husky's ability to enter, and the associated costs of entering, (i) into ordinary course derivative or hedging transactions, which may require Husky to post additional collateral under certain of its contracts if certain adverse events occur with respect to credit ratings, and (ii) into and maintaining ordinary course contracts with customers and suppliers on acceptable terms.

	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)

Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit ratings accorded to Husky'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 pays an annual fee to Standard and Poor's, Moody's and Dominion Bond Rating Services Limited. Additionally, Husky pays a fee to credit rating agencies in order to receive a rating for debt or equity instruments upon issuance.

Moody's

Moody's long-term credit ratings are on a rating scale that ranges from Aaa (highest) to C (lowest). A rating of Baa2 by Moody's is within the fourth highest of nine categories and is assigned to debt securities which are considered medium-grade (i.e., they are subject to moderate credit risk). Such debt securities may possess certain speculative characteristics. The addition of a 1, 2 or 3 modifier after a rating indicates the relative standing within a particular rating category. The modifier 1 indicates that the issue ranks in the higher end of its generic rating category, the modifier 2 indicates a mid-range ranking and the modifier 3 indicates a ranking in the lower end of that generic rating category.

Standard and Poor's

Standard and Poor's long-term credit ratings are on a rating scale that ranges from AAA (highest) to D (lowest). A rating of BBB+ by Standard & Poor's is within the fourth highest of 10 categories and indicates that the obligation exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within the major rating categories.

Standard and Poor's began rating Husky's Series 1 Preferred Shares and Series 2 Preferred Shares, Series 3 Preferred Shares, Series 5 Preferred Shares and Series 7 Preferred Shares on its Canadian preferred share scale on March 18, 2011, December 9, 2014, March 12, 2015 and June 17, 2015, respectively. Preferred share ratings are a forward-looking opinion about the creditworthiness of an issuer with respect to a specific preferred share obligation. There is a direct correspondence between the ratings assigned on the preferred share scale and Standard & Poor's ratings scale for long-term credit ratings. According to Standard and Poor's ratings system, a P 2 (low) rating on the Canadian preferred share rating scale is equivalent to a BBB- rating on the long-term credit rating scale.

Dominion Bond Rating Service

Dominion Bond Rating Service's long-term credit ratings are on a rating scale that ranges from AAA (highest) to D (lowest). A rating of A (low) by Dominion Bond Rating Service is within the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality. The capacity for payment of financial obligations is substantial, but of lesser credit quality than that of higher rated securities. Entities in the A category may be vulnerable to future events, but qualifying negative factors are considered manageable. The assignment of a "(high)" or "(low)" modifier within each rating category indicates relative standing within such category.

Dominion Bond Rating Service began rating Husky's Series 1 Preferred Shares and Series 2 Preferred Shares, Series 3 Preferred Shares, Series 5 Preferred Shares, and Series 7 Preferred Shares on its Canadian preferred share scale on March 18, 2011, December 9, 2014, March 12, 2015 and June 17, 2015, respectively. Preferred share ratings are meant to give an indication of the risk that an issuer will not fulfill its full obligations in a timely manner, with respect to both dividend and principal commitments. Dominion Bond Rating Service preferred share ratings range from Pdf-1 (highest) to D (lowest). According to the Dominion Bond Rating Service ratings system, preferred shares rated Pfd-2 are of satisfactory credit quality where protection of dividends and principal is still substantial, but earnings, the balance sheet and coverage ratios are not as strong as Pfd-1 rated companies.

Dominion Bond Rating Service began rating Husky's commercial paper on September 4, 2014. Credit ratings on commercial paper are on a short-term debt rating scale that ranges from R-1 (high) to D1 representing the range of such securities rated from highest to lowest qualify. A rating of R-1 (low) by Dominion Bond Rating Service is the third highest of 10 categories and is assigned to debt securities considered to be of good credit quality. The capacity for the payment of short-term financial obligations as they become due is substantial with overall strength not as favourable as higher rating categories. Entities in this category may be vulnerable to future events, but qualifying negative factors are considered manageable. The R-1 and R-2 commercial paper categories are denoted by (high), (middle) and (low) designations.

MARKET FOR SECURITIES

Husky's common shares, Series 1 Preferred Shares, Series 2 Preferred Shares, Series 3 Preferred Shares, Series 5 Preferred Shares, and Series 7 Preferred Shares are listed and posted for trading on the Toronto Stock Exchange ("TSX") under the respective trading symbols "HSE","HSE.PR.A","HSE.PR.B","HSE.PR.C","HSE.PR.E" and "HSE.PR.G".The Series 1 Preferred Shares began trading on the TSX on March 18, 2011. The Series 2 Preferred Shares began trading on the TSX on April 1, 2016. The Series 3 Preferred Shares began trading on the TSX on December 9, 2014. The Series 5 Preferred Shares began trading on the TSX on March 12, 2015. The Series 7 Preferred Shares began trading on the TSX on June 17, 2015.

The following table discloses the trading price range and volume of Husky's common shares traded on the TSX during Husky's financial year ended December 31, 2017:

	High	Low	Volume *(000's)*
January	17.42	15.93	23,920
February	16.89	15.31	25,810
March	16.33	14.94	30,253
April	16.12	14.80	19,826
May	16.61	15.32	22,030
June	16.15	14.71	23,350
July	14.90	13.39	18,292
August	14.94	14.10	14,185
September	15.78	14.30	20,151
October	16.81	15.40	17,371
November	16.99	15.09	20,850
December	17.83	15.29	19,488

The following table discloses the trading price range and volume of the Series 1 Preferred Shares traded on the TSX during Husky's financial year ended December 31, 2017:

	High	Low	Volume *(000's)*
January	15.44	13.42	227
February	16.22	14.90	331
March	16.91	15.66	158
April	16.80	15.80	196
May	16.40	15.06	165
June	16.18	15.19	92
July	16.80	16.05	115
August	16.90	16.55	283
September	17.25	16.45	119
October	17.84	17.18	114
November	18.21	17.43	47
December	17.89	16.70	161

The following table discloses the trading price range and volume of the Series 2 Preferred Shares traded on the TSX during Husky's financial year ended December 31, 2017:

	High	Low	Volume *(000's)*
January	14.26	12.91	18
February	15.30	14.10	32
March	16.00	15.03	16
April	15.98	15.36	26
May	15.38	14.52	42
June	15.75	14.11	24
July	16.35	15.63	16
August	16.35	16.01	20
September	17.26	16.48	21
October	17.93	17.06	13
November	17.65	17.25	54
December	17.52	16.61	30

The following table discloses the trading price range and volume of the Series 3 Preferred Shares traded on the TSX during Husky's financial year ended December 31, 2017:

	High	Low	Volume *(000's)*
January	23.46	21.70	277
February	23.62	22.85	179
March	23.58	22.95	254
April	24.11	23.06	174
May	23.84	22.78	304
June	23.49	22.53	388
July	23.84	23.35	148
August	23.80	22.30	83
September	24.21	22.81	109
October	24.49	23.94	67
November	25.00	24.24	108
December	24.79	23.90	119

The following table discloses the trading price range and volume of the Series 5 Preferred Shares traded on the TSX during Husky's financial year ended December 31, 2017:

	High	Low	Volume *(000's)*
January	24.62	22.80	174
February	24.58	23.74	117
March	24.51	23.94	200
April	24.91	24.24	144
May	24.54	23.62	272
June	24.52	23.58	154
July	24.74	24.29	68
August	24.56	23.55	66
September	24.74	23.78	91
October	24.97	24.43	60
November	25.08	24.66	83
December	24.99	24.41	244

The following table discloses the trading price range and volume of the Series 7 Preferred Shares traded on the TSX during Husky's financial year ended December 31, 2017:

	High	Low	Volume *(000's)*
January	24.51	22.87	282
February	24.60	24.03	233
March	24.49	24.03	279
April	24.81	24.27	235
May	24.40	23.75	301
June	24.55	23.53	105
July	24.70	24.25	78
August	24.50	23.67	58
September	24.69	23.93	29
October	25.18	24.70	56
November	25.20	24.80	51
December	25.00	24.30	80

DIRECTORS AND OFFICERS

Directors

The following are the names and residences of the directors of Husky as of the date of this AIF, their positions and offices with Husky and their principal occupations for at least the five preceding years. Each director will hold office until the Company's next annual meeting or until his or her successor is appointed or elected.

Name & Residence	Office or Position	Principal Occupation During Past Five Years
Li, Victor T.K. Hong Kong Special Administrative Region	Co-Chair of the Board Director since August 2000	Mr. Li is the Group Co-Managing Director and Deputy Chairman of CK Hutchison Holdings Limited. He is also the Managing Director and Deputy Chairman of CK Asset Holdings Limited (formerly known as Cheung Kong Property Holdings Limited). He is also the Chairman and Executive Director of CK Infrastructure Holdings Limited (formerly known as Cheung Kong Infrastructure Holdings Limited) and CK Life Sciences Int'l., (Holdings) Inc., a Non-Executive Director of Power Assets Holdings Limited and HK Electric Investments Manager Limited which is the trustee-manager of HK Electric Investments, and a Non-Executive Director and the Deputy Chairman of HK Electric Investments Limited. Mr. Li is also the Deputy Chairman of Li Ka Shing Foundation Limited, Li Ka Shing (Overseas) Foundation and Li Ka Shing (Canada) Foundation, and a Non-Executive Director of The Hongkong and Shanghai Banking Corporation Limited. Mr. Li serves as a member of the Standing Committee of the 12th National Committee of the Chinese People's Political Consultative Conference of the People's Republic of China. He is also Vice Chairman of the Hong Kong General Chamber of Commerce. Mr. Li is the Honorary Consul of Barbados in Hong Kong. He was previously a member of the Commission on Strategic Development of the Hong Kong Special Administrative Region. Mr. Li holds a Bachelor of Science degree in Civil Engineering and a Master of Science degree in Civil Engineering, both received from Stanford University in 1987. He obtained an honorary degree, Doctor of Laws, honoris causa (LL.D.) from The University of Western Ontario in 2009.
Fok, Canning K.N. Hong Kong Special Administrative Region	Co-Chair of the Board and Chair of the Compensation Committee Director since August 2000	Mr. Fok is an Executive Director and Group Co-Managing Director of CK Hutchison Holdings Limited. Mr. Fok is Chairman and a Director of Hutchison Telecommunications Hong Kong Holdings Limited, Hutchison Telecommunications (Australia) Limited, Hutchison Port Holdings Management Pte. Limited as the trustee-manager of Hutchison Port Holdings Trust, Power Assets Holdings Limited, HK Electric Investments Manager Limited as the trustee-manager of HK Electric Investments, and HK Electric Investments Limited. Mr. Fok is Deputy Chairman and an Executive Director of CK Infrastructure Holdings Limited (formerly known as Cheung Kong Infrastructure Holdings Limited). Mr. Fok obtained a Bachelor of Arts degree from St. John's University, Minnesota in 1974 and a Diploma in Financial Management from the University of New England, Australia in 1976. He has been a member of the Institute of Chartered Accountants in Australia (which amalgamated with the New Zealand Institute of Chartered Accountants to become Chartered Accountants Australia and New Zealand) since 1979 and has been a Fellow of the Chartered Accountants Australia and New Zealand since 2015.

Bradley, Stephen E. Beijing, People's Republic of China	Member of the Audit Committee and the Corporate Governance Committee Director since July 2010	Mr. Bradley is a Director of Broadlea Group Ltd., Senior Consultant, NEX (formerly known as ICAP (Asia Pacific) Ltd.) and a Director of Swire Properties Ltd. (Hong Kong). Mr. Bradley entered the British Diplomatic Service in 1981 and served in various capacities including Director of Trade & Investment Promotions (Paris) from 1999 to 2002; Minister, Deputy Head of Mission & Consul-General (Beijing) from 2002 to 2003 and HM Consul-General (Hong Kong) from 2003 to 2008. Mr. Bradley also worked in the private sector as Marketing Director, Guinness Peat Aviation (Asia) from 1987 to 1988 and Associate Director, Lloyd George Investment Management (now part of BMO Global Asset Management) from 1993 to 1995. Mr. Bradley retired from the Diplomatic Service in 2009. Mr. Bradley obtained a Bachelor of Arts degree from Balliol College, Oxford University in 1980 and a post-graduate diploma from Fudan University, Shanghai in 1981. Mr. Bradley is a Member of the Hong Kong Securities and Investment Institute and an ICD.D with the Institute of Corporate Directors of Canada.
Ghosh, Asim Hong Kong Special Administrative Region	Director since May 2009	Mr. Ghosh has been on the Board of Directors of Husky Energy since May 2009 and was President & Chief Executive Officer from June 2010 until his retirement in December 2016. He is the former Managing Director and Chief Executive Officer of Vodafone Essar Limited. Under his leadership the cellular phone company grew from a virtual startup in 1998 to become one of the largest mobile companies in the world by subscribers. Mr. Ghosh started his career with Procter & Gamble in Canada and subsequently became a Senior Vice President of Carling O'Keefe. He later became founding co-Chief Executive Officer of Pepsi Food's start up operations in India. He served in senior executive positions and as Chief Executive Officer of the AS Watson consumer packaged goods subsidiary of Hutchison Whampoa. From 1991 to 1998 he managed a group of 13 business units, and expanded the group's operations from Hong Kong to China and Europe. Mr. Ghosh received his Master of Business Administration from Wharton School at the University of Pennsylvania, and obtained his undergraduate degree in Electrical Engineering from the Indian Institute of Technology.
Glynn, Martin J.G. British Columbia, Canada	Chair of the Corporate Governance Committee and a Member of the Compensation Committee Director since August 2000	Mr. Glynn is a Director and Chair Designate of Public Sector Pension Investment Board (PSP Investments), and a Director of Sun Life Financial Inc. and Sun Life Assurance Company of Canada. Mr. Glynn was a Director from 2000 to 2006 and President and Chief Executive Officer of HSBC Bank USA N.A. from 2003 until his retirement in 2006. Mr. Glynn was a Director of HSBC Bank Canada from 1999 to 2006 and President and Chief Executive Officer from 1999 to 2003. Mr. Glynn obtained a Bachelor of Arts (Honours) degree from Carleton University, Canada in 1974 and a Master's degree in Business Administration from the University of British Columbia in 1976.

Koh, Poh Chan Hong Kong Special Administrative Region	Director since August 2000	Ms. Koh is Finance Director of Harbour Plaza Hotel Management (International) Ltd. (a hotel management company) and also a Member of the Executive Committee of CK Asset Holdings Limited. Ms. Koh is qualified as a Fellow Member (FCA) of the Institute of Chartered Accountants in England and Wales and is an Associate of the Canadian Institute of Chartered Accountants (CPA, CA) and the Chartered Institute of Taxation in the U.K. (CTA). Ms. Koh graduated from the London School of Accountancy in 1971 and was admitted to the Institute of Chartered Accountants in England and Wales in 1973, to the Chartered Institute of Taxation in the UK in 1976 as well as the Institute of Chartered Accountants of Ontario, Canada in 1980.
Kwok, Eva L. British Columbia, Canada	Member of the Compensation Committee and the Corporate Governance Committee	Mrs. Kwok is Chairman, a Director and Chief Executive Officer of Amara Holdings Inc. (a private investment holding company). Mrs. Kwok is also a Director of CK Life Sciences Int'l., (Holdings) Inc. and CK Infrastucture Holdings Limited (formerly known as Cheung Kong Infrastructure Holdings Limited). Mrs. Kwok is also a Director of the Li Ka Shing (Canada) Foundation.
	Director since August 2000	Mrs. Kwok was a Director of Shoppers Drug Mart Corporation from 2004 to 2006 and of the Bank of Montreal Group of Companies from 1999 until March 2009. Mrs. Kwok obtained a Master's degree in Science from the University of London in 1967.
Kwok, Stanley T.L. British Columbia, Canada	Chair of the Health, Safety and Environment Committee	Mr. Kwok is a Director and President of Stanley Kwok Consultants (a planning and development company) and Amara Holdings Inc. He is an independent Non-Executive Director of CK Hutchison Holdings Limited.
	Director since August 2000	Mr. Kwok is a Director of Element Lifestyle Retirement Inc. He retired as a Director of the CTBC Bank of Canada in July, 2017. Mr. Kwok obtained a Bachelor of Science degree (Architecture) from St. John's University, Shanghai in 1949, and an A.A. Diploma from the Architectural Association School of Architecture in London, England in 1954.
Ma, Frederick S. H. Hong Kong Special Administrative Region	Member of the Audit Committee and the Health, Safety and Environment Committee	Professor Ma has held senior management positions in international financial institutions and Hong Kong publicly listed companies in his career.He was also a former Principal Official with the Hong Kong Special Administrative Region Government.
	Director since July 2010	In addition to being a Director of Husky, he is currently the Non- Executive Chairman of MTR Corporation Limited (formerly Mass Transit Railway Corporation). He is currently a Non-Executive Director of COFCO Corporation. In July 2002, Professor Ma joined the Government of the Hong Kong Special Administrative Region as the Secretary for Financial Services and the Treasury. He assumed the post of Secretary for Commerce and Economic Development in July 2007, but resigned from the Government in July 2008 due to medical reasons. Professor Ma was appointed as a member of the International Advisory Council of China Investment Corporation in July 2009. In January 2013, he was appointed a member of the Global Advisory Council of the Bank of America. Professor Ma was appointed as an Honorary Professor of the School of Economics and Finance at the University of Hong Kong in October 2008. In August 2013, he was appointed as an Honorary Professor of the Faculty of Business Administration at the Chinese University of Hong Kong. Professor Ma obtained a Bachelor of Arts (Honours) degree in Economics and History from the University of Hong Kong in 1973, an Honorary Doctor of Social Sciences in October 2014 from Lingnan University and an Honorary Doctor of Social Sciences in October 2016 from City University of Hong Kong.

Magnus, George C. Hong Kong Special Administrative Region	Member of the Audit Committee Director since July 2010	Mr. Magnus is a Non-Executive Director of CK Hutchison Holdings Limited and CK Infrastructure Holdings Limited (formerly known as Cheung Kong Infrastructure Holdings Limited), and an independent Non-Executive Director of HK Electric Investments Manager Limited. Mr. Magnus acted as an Executive Director of Cheung Kong (Holdings) Limited from 1980 and as Deputy Chairman from 1985 until his retirement from these positions in October 2005. He served as Deputy Chairman of Hutchison Whampoa Limited from 1985 to 1993 and as Executive Director from 1993 to 2005. He also served as Chairman of Hongkong Electric Holdings Limited (now known as Power Assets Holdings Limited) from 1993 to 2005. He was a Non-Executive Director of Power Assets Holding Limited from 2005 to 2012 and then an independent Non-Executive Director until January 2014. Mr. Magnus obtained a Bachelor of Arts degree in 1959. He obtained a Master's degree in Economics from King's College, Cambridge University in 1963.
McGee, Neil D. Luxembourg	Member of the Health, Safety and Environment Committee Director since November 2012	Mr. McGee is the Managing Director of Hutchison Whampoa Europe Investments S.à r.l. He is an Executive Director of Power Assets Holdings Limited. Prior to his joining Hutchison Whampoa Europe Investments S.à r.l., he served as Group Finance Director of Power Assets Holdings Limited from 2006 to 2012, Chief Financial Officer of Husky Oil Limited from 1998 to 2000 and Chief Financial Officer of Husky Energy Inc. from 2000 to 2005. Prior to joining Husky Oil Limited in 1998, Mr. McGee held various financial, legal and corporate secretarial positions with the CK Hutchison Holdings Group. Mr. McGee holds a Bachelor of Arts degree and a Bachelor of Laws degree from the Australian National University.
Peabody, Robert J. Alberta, Canada	President & Chief Executive Officer Director since December 2016	Mr. Peabody became a member of the Board of Directors and President and Chief Executive Officer of Husky on December 5, 2016. Mr. Peabody was appointed Chief Operating Officer in 2006 and was responsible for leading Husky's Upstream and Downstream segments, including Western Canada Conventional and Unconventional, Heavy Oil, Oil Sands, Atlantic Region and Exploration, as well as Refining and Upgrading operations. He was also responsible for the Safety, Engineering, Project Management and Procurement functions. Prior to joining Husky, he led four major businesses for BP plc in Europe and the United States. Mr. Peabody holds a Bachelor of Science degree in Mechanical Engineering from the University of British Columbia and a Master of Science degree in Management (Sloan Fellow) from Stanford University. Mr. Peabody is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and Vice-Chairman of the Foothills Hospital Development Council.
Russel, Colin S. Gloucestershire, United Kingdom	Member of the Audit Committee and the Health, Safety and Environment Committee Director since February 2008	Mr. Russel is the founder and a director of Emerging Markets Advisory Services Ltd. (a business advisory company). Mr. Russel is a Director of CK Infrastructure Holdings Limited (formerly known as Cheung Kong Infrastructure Holdings Limited), CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd. Mr. Russel was the Canadian Ambassador to Venezuela; Consul General for Canada in Hong Kong; Director for China of the Department of Foreign Affairs, Ottawa; Director for East Asian Trade in Ottawa; Senior Trade Commissioner for Canada in Hong Kong; Director for Japan Trade in Ottawa and was in the Trade Commissioner Service for Canada in Spain, Hong Kong, Morocco, the Philippines, London and India. Previously Mr. Russel was an international project manager with RCA Ltd., Canada and development engineer with AEI Ltd., UK. Mr. Russel received a degree in Electrical Engineering in 1962 and a Master's degree in Business Administration in 1971, both from McGill University, Canada.

Shaw, Wayne E. Ontario, Canada	Member of the Audit Committee and the Corporate Governance Committee Director since August 2000	Mr. Shaw is the President of G.E. Shaw Investments Limited. Prior to his retirement in April 2013, he was a Senior Partner with Stikeman Elliott LLP,Barristers and Solicitors. Mr. Shaw is also a Director of the Li Ka Shing (Canada) Foundation. Mr. Shaw holds a Bachelor of Arts degree and a Bachelor of Laws degree, both received from the University of Alberta in 1967. He is a member of the Law Society of Upper Canada.
Shurniak, William Saskatchewan, Canada	Deputy Chair of the Board and Chair of the Audit Committee Director since August 2000	Mr. Shurniak was an independent Non-Executive Director of Hutchison Whampoa Limited until June 2015, when he became an independent Non-Executive Director of CK Hutchison Holdings Limited. From May 2005 to June 2011 he was a Director and Chairman of Northern Gas Networks Limited (a private distributor of natural gas in Northern England). Mr. Shurniak also held the following positions until his return to Canada in 2005: Director and Chairman of ETSA Utilities (a utility company) since 2000, Powercor Australia Limited (a utility company) since 2000, CitiPower Pty Ltd. (a utility company) since 2002, and a Director of Envestra Limited (a natural gas distributor) since 2000, CrossCity Motorways Pty Ltd. (an infrastructure and transportation company) since 2002 and Lane Cove Tunnel Company Pty Ltd. (an infrastructure and transportation company) since 2004. Mr. Shurniak obtained an Honorary Doctor of Laws degree from the University of Saskatchewan in May 1998 and from The University of Western Ontario in October 2000. On July 30, 2005, he was a recipient of the Saskatchewan Centennial Medal from the Lieutenant Governor of Saskatchewan. In 2009 he was awarded the Saskatchewan Order of Merit by the Government of the Province of Saskatchewan. In December 2012, Mr. Shurniak was a recipient of The Queen Elizabeth II Diamond Jubilee Medal from the Lieutenant Governor of Saskatchewan. On June 4, 2014, the University of Regina conferred an Honorary Doctor of Laws degree on Mr. Shurniak and on November 10, 2016 he was awarded the Meritorious Service Medal by the Governor General of Canada.
Sixt, Frank J. Hong Kong Special Administrative Region	Member of the Compensation Committee Director since August 2000	Mr. Sixt is an Executive Director, Group Finance Director and Deputy Managing Director of CK Hutchison Holdings Limited. Mr. Sixt is also the Non-Executive Chairman of TOM Group Limited, an Executive Director of CK Infrastructure Holdings Limited (formerly known as Cheung Kong Infrastructure Holdings Limited), a Director of Hutchison Telecommunications (Australia) Limited (HTAL) and an Alternate Director to a Director of HTAL, HK Electric Investments Manager Limited as the trustee-manager of HK Electric Investments and HK Electric Investments Limited. Mr. Sixt is also a Director of the Li Ka Shing (Canada) Foundation. Mr. Sixt obtained a Master's degree in Arts from McGill University, Canada in 1978 and a Bachelor's degree in Civil Law from Université de Montréal in 1978. He is a member of the Bar and of the Law Society of the Provinces of Quebec and Ontario, Canada.

Officers

The following are the names and residences of the officers of Husky as of the date of this AIF, their positions and offices with Husky and their principal occupations for at least the five preceding years.

Name and Residence	Office or Position	Principal Occupation During Past Five Years
Peabody, Robert J. Alberta, Canada	President & Chief Executive Officer	President & Chief Executive Officer of Husky since December 2016. Chief Operating Officer of Husky from April 2006 to December 2016.
McKenzie, Jonathan M. Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Husky since April 2015. Chief Commercial Financial Officer of Irving Oil Ltd. from April 2011 to April 2015. Vice President & Controller of Suncor Energy Inc. from March 2009 to May 2011.
Symonds, Robert W. P. Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Husky since March 2017. Senior Vice President, Western Canada Production of Husky Oil Operations Limited from April 2012 to March 2017.
Girgulis, James D. Alberta, Canada	Senior Vice President, General Counsel & Secretary	Senior Vice President, General Counsel & Secretary since April 2012. Vice President, Legal & Corporate Secretary of Husky from August 2000 to April 2012.

As at February 15, 2018, the directors and officers of Husky, as a group, beneficially owned or controlled or directed, directly or indirectly, 808,801 common shares of Husky, representing less than one percent of the issued and outstanding common shares.

Conflicts of Interest

The officers and directors of Husky may also become officers and/or directors of other companies engaged in the oil and gas business generally and which may own interests in oil and gas properties in which Husky holds or may in the future, hold an interest. As a result, situations may arise where the interests of such directors and officers conflict with their interests as directors and officers of other companies. In the case of the directors, the resolution of such conflicts is governed by applicable corporate laws that require that directors act honestly, in good faith and with a view to the best interests of Husky and, in respect of the Business Corporations Act (Alberta), Husky's governing statute that directors declare, and refrain from voting on, any matter in which a director may have a conflict of interest.

Corporate Cease Trade Orders or Bankruptcies

None of those persons who are directors or executive officers of Husky is or have been within the past ten years, a director, chief executive officer or chief financial officer of any company, including Husky and any personal holding companies of such person that, while such person was acting in that capacity, was the subject of a cease trade or similar order or an order that denied the Company access to any exemption under securities legislation, for a period of more than 30 consecutive days, or after such persons ceased to be a director, chief executive officer or chief financial officer of the Company was the subject of a cease trade or similar order or an order that denied the Company access to any exemption under securities legislation, for a period of more than 30 consecutive days, which resulted from an event that occurred while such person was acting in such capacity.

In addition, none of those persons who are directors or executive officers of Husky is, or has been within the past ten years, a director or executive officer of any company, including Husky and any personal holding companies of such persons, that while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than as follows. Mr. Glynn was director of MF Global Holdings Ltd. when it filed for Chapter 11 bankruptcy in the U.S. on October 31, 2011. Mr. Glynn is no longer a director of MF Global Holdings Ltd.

Individual Penalties, Sanctions or Bankruptcies

None of the persons who are directors or executive officers of Husky (or any personal holding companies of such persons) have, within the past ten years become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or were subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold his or her assets.

None of the persons who are directors or executive officers of the Company (or any personal holding companies of such persons) have been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or have entered into a settlement agreement with a securities regulatory authority or been subject to any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

AUDIT COMMITTEE

Composition

The members of Husky's Audit Committee (the "Committee") are William Shurniak (Chair), Stephen E. Bradley, Frederick S. H. Ma, George C. Magnus, Colin S. Russel and Wayne E. Shaw. Each of the members of the Committee is independent in that each member does not have a direct or indirect material relationship with the Company. Multilateral Instrument 52-110 Audit Committees provides that a material relationship is a relationship which could, in the view of the Company's Board of Directors, reasonably interfere with the exercise of a member's independent judgment.

The Committee's Mandate provides that the Committee is to be comprised of at least three members of the Board, all of whom shall be independent and meet the financial literacy requirements of applicable laws and regulations. Each member of the Committee is financially literate in that each has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by the Company's financial statements.

The education and experience of each Committee member that is relevant to the performance of his responsibilities as a Committee member is as follows.

William Shurniak (Chair) - Mr. Shurniak was an independent Non-Executive Director of Hutchison Whampoa Limited until June 2015, when he became an independent Non-Executive Director of CK Hutchison Holdings Limited, a newly listed company on The Stock Exchange of Hong Kong Limited. From May 2005 to June 2011 he was a Director and Chairman of Northern Gas Networks Limited (a private distributor of natural gas in Northern England).

Stephen E. Bradley - Mr. Bradley is a Director of Broadlea Group Ltd., Senior Consultant, ICAP (Asia Pacific) and a Director of Swire Properties Ltd. (Hong Kong).

Frederick S. H. Ma - Professor Ma has served in senior positions in the private sector and has held Principal Official positions (minister equivalent) with the Hong Kong Special Administrative Region Government. Professor Ma is currently a member of the International Advisory Council of China Investment Corporation, China's Sovereign Fund, as well as an Honorary Professor of the University of Hong Kong.

George C. Magnus - Mr. Magnus is a Non-Executive Director of CK Hutchison Holdings Limited and Cheung Kong Infrastructure Holdings Limited and an independent Non-Executive Director of HK Electric Investments Manager Limited and HK Electric Investments Limited.

Colin S. Russel - Mr. Russel is the founder and Managing Director of Emerging Markets Advisory Services Ltd. Mr. Russel is a director and an audit committee member of Cheung Kong Infrastructure Holdings Limited, CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd.

Wayne E. Shaw - Mr. Shaw is the President of G.E. Shaw Investments ULC. Prior to his retirement in April 2013, he was a Senior Partner with Stikeman Elliott LLP, Barristers and Solicitors. Mr. Shaw is also a Director of the Li Ka Shing (Canada) Foundation.

Husky's Audit Committee Mandate is attached hereto as Appendix A.

External Auditor Service Fees

The following table provides information about the fees billed to the Company for professional services rendered by KPMG LLP, the Company's external auditor, during the fiscal years indicated:

($ thousands)	**2017**	2016
Audit Fees	**3,861**	3,858
Audit-related Fees	**256**	158
Tax Fees	**121**	350
	4,238	4,366

Audit fees consist of fees for the audit of the Company's annual financial statements or services that are normally provided in connection with statutory and regulatory filings, including the Sarbanes-Oxley Act of 2002. Audit-related fees included fees for attest services not required by statute or regulation. Tax fees included fees for tax planning and various taxation matters.

The Committee has the sole authority to review in advance, and grant any appropriate pre-approvals, of all non-audit services to be provided by the independent auditors and to approve fees, in connection therewith. The Committee pre-approved all of the audit-related and tax services provided by KPMG LLP in 2017.

LEGAL PROCEEDINGS

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 the outcome of adverse decisions in any pending or threatened proceedings related to these or other matters or any amount which it may be required to pay by reason thereof would have a material adverse impact on its financial condition, results of operations or liquidity.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Company's directors, executive officers or persons or companies that beneficially own or control or direct, directly or indirectly or a combination of both, more than 10 percent of Husky's common shares, or their associates and affiliates, had any material interest, direct or indirect, in any transaction with the Company within the three most recently completed financial years or during the current financial year that has materially affected or would reasonably be expected to materially affect the Company.

TRANSFER AGENTS AND REGISTRARS

Husky's transfer agent and registrar is Computershare Trust Company of Canada. In the United States, the transfer agent and registrar is Computershare Trust Company, Inc. The registers for transfers of the Company's common and preferred shares are maintained by Computershare Trust Company of Canada at its principal offices in the cities of Calgary, Alberta and Toronto, Ontario. Queries should be directed to Computershare Trust Company at 1-800-564-6253 or 1-514-982-7555.

INTERESTS OF EXPERTS

Certain information relating to the Company's reserves included in this AIF has been calculated by the Company and audited and opined upon as at December 31, 2017 by Sproule. Sproule is an independent petroleum engineering consultant retained by Husky, and such reserves information has been so included in reliance on the opinion and analysis of Sproule, given upon the authority of said firm as experts in reserves engineering. The partners, employees and consultants of Sproule, as a group beneficially own, directly or indirectly, less than one percent of the Company's securities of any class.

KPMG LLP are the auditors of the Company and have confirmed that they are independent with respect to the Company within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations and also that they are independent accountants with respect to the Company under all relevant U.S. professional and regulatory standards.

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal shareholders of Husky's common shares and a description of options to purchase common shares is contained in Husky's Management Information Circular prepared in connection with the annual meeting of shareholders held on May 5, 2017.

Additional financial information is provided in Husky's audited consolidated financial statements and management's discussion and analysis ("MD&A") for the financial year ended December 31, 2017.

Additional information relating to Husky Energy Inc. is available on the System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com and on the Electronic Data Gathering, Analysis, and Retrieval system ("EDGAR") at www.sec.gov.

Forward-looking Statements

Certain statements in this AIF 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 AIF 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”, “estimated”, “intend”, “plan”, “projection”, “could”, “aim”, “vision”, “goals”, “objective”, “target”, “scheduled” and “outlook”). In particular, forward-looking statements in this AIF 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; expected effects of abandonment and reclamation costs, development costs, and operating costs on anticipated development or production activities on properties with no attributed reserves; scheduled timing of development of the Company’s proved and probable undeveloped reserves; expected sources of funding for future development costs; estimates of the forecasted costs of developing the Company’s proved and proved plus probable reserves as at December 31, 2017; the Company’s 2018 production estimates broken down by product type and location; anticipated effects of and cost of compliance with certain future or proposed laws and regulations on the Company’s operations; and plans to expand the market for the Company’s crude oil into the midwest U.S.;
- with respect to the Company’s thermal developments in the Integrated Corridor: expected timing for first production at, and design capacity for, the Rush Lake 2, Dee Valley, Spruce Lake North, Spruce Lake Central, Edam Central and West Hazel thermal developments; expected timing to start construction at the Dee Valley Project; expected timing to start site clearing and construction at the Spruce Lake Central and Spruce Lake North projects; expected timing to reach 30,000 bbls/day at the Tucker Thermal Project; and expected timing to reach nameplate capacity at the Sunrise Energy Project;
- with respect to the Company’s Western Canada and other resource plays: growth strategies and development opportunities; expected timing that six wells in the Spirit River formation will come on production; expected timing that two wells at Wembley will come on production; expected timing to complete and put on production four wells in the Cardium oil play; drilling plans for 2018 in the Foothills area; and plans for the Northwest Territories;
- with respect to the Company’s Offshore business in Asia Pacific: development plans for the Liuhua 29-1 field, including expected timing to commence construction and for first production; expected timing to drill exploration wells on Block 15/33 and Block 16/25; expected timing to reach full sales production targets at the BD field; expected timing to drill wells in the MDA and MBH fields; expected timing for production from the MDA, MBH and MDK fields; and expected working interest sales volumes from the BD, MDA, MBH and MDK fields once production is fully ramped up;
- with respect to the Company’s Offshore business in Atlantic, development plans, expected timing of first oil, expected volume and timing of peak production and estimated construction costs at West White Rose;
- with respect to the Company’s Infrastructure and Marketing business: growth strategies and projects for HMLP, including plans to commission a 150-kilometre pipeline; and expansion plans for the Hardisty terminal;
- with respect to the Company’s Downstream operating segment: plans to increase asphalt modification capacity, expanding U.S. asphalt retail sales and marketing residual production; anticipated timing of completion, outcome and benefits of the reliability and profitability improvement projects at the Lima Refinery; and plans to process bitumen from the Sunrise Energy Project;

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 reserve and production estimates.

Although the Company believes that the expectations reflected by the forward-looking statements presented in this AIF are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events 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. The material factors and assumptions used to develop the forward-looking statements include, but are not limited to:

- with respect to the business, operations and results of the Company generally: the absence of significant adverse changes to commodity prices, interest rates, applicable royalty rates and tax laws, and foreign exchange rates; the absence of significant adverse changes to energy markets, competitive conditions, the supply and demand for crude oil, natural gas, NGL and refined petroleum products, or the political, economic and social stability of the jurisdictions in which the Company operates; continuing availability of economical capital resources, labour and services; demand for products and cost of operations; the absence of significant adverse legislative and regulatory changes, in particular changes to the legislation and regulation governing fiscal regimes and environmental issues; and stability of general domestic and global economic, market and business conditions;
- with respect to the Company's Offshore business in Asia Pacific and Atlantic, thermal developments in the Integrated Corridor, Western Canada resource plays and Infrastructure and Marketing business: the accuracy of future production rates and reserve estimates; the securing of sales agreements to underpin the commercial development and regulatory approvals for the development of the Company's properties; the absence of significant delays in the procurement, development, construction or commissioning of the Company's projects, for which the Company or a third party is the designated operator, that may result from the inability of suppliers to meet their commitments, lack of regulatory or third-party approvals or other governmental actions, harsh weather or other calamitous event; the absence of significant disruption of operations such as may result from harsh weather, natural disaster, accident, civil unrest or other calamitous event; the absence of significant unexpected technological or commercial difficulties that adversely affect exploration, development, production, processing or transportation; the sufficiency of budgeted capital expenditures in carrying out planned activities; and the absence of significant increases in the cost of major growth projects; and
- with respect to the Company's Downstream operating segment: the absence of significant delays in the development, construction or commissioning of the Company's projects that may result from the inability of suppliers to meet their commitments, lack of regulatory or third-party approvals or other governmental actions, harsh weather or other calamitous event; the absence of significant disruption of operations such as may result from harsh weather, natural disaster, accident, civil unrest or other calamitous event; the absence of significant unexpected technological or commercial difficulties that adversely affect processing or transportation; the sufficiency of budgeted capital expenditures in carrying out planned activities; and the absence of significant increase in the cost of major growth projects.

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 Husky. The risks, uncertainties and other factors, many of which are beyond Husky's control, that could cause actual results to differ (potentially significantly) from those expressed in the forward-looking statements include, but are not limited to:

- with respect to the business, operations and results of the Company generally: those risks, uncertainties and other factors described under "Risk Factors"in this AIF and throughout the Company's MD&A for the year ended December 31, 2017; the demand for the Company's products and prices received for crude oil and natural gas production and refined petroleum products; the economic conditions of the markets in which the Company conducts business; the exchange rate between the Canadian and U.S. dollar; the foreign currency risk relating to the Block 29/26 gas and liquids sales agreements which are denominated in Chinese Yen; the ability to replace reserves of oil and gas, whether sourced from exploration, improved recovery or acquisitions; potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdictions where the Company has operations; changes to royalty regimes; changes to government fiscal, monetary and other financial policies; changes in workforce demographics; and the cost and availability of capital, including access to capital markets at acceptable rates;

- with respect to the Company's Offshore business in Asia Pacific and Atlantic, thermal developments in the Integrated Corridor, Western Canada resource plays and Infrastructure and Marketing business: the availability of prospective drilling rights; the costs to acquire exploration rights, undertake geological studies, appraisal drilling and project development; the availability and cost of labour, technical expertise, material and equipment to efficiently, effectively and safely undertake capital projects; the costs to operate properties, plants and equipment in an efficient, reliable and safe manner; prevailing climatic conditions in the Company's operating locations; regulations to deal with climate change issues; the competitive actions of other companies, including increased competition from other oil and gas companies; business interruptions because of unexpected events such as fires, blowouts, freeze-ups, equipment failures and other similar events affecting the Company or other parties whose operations or assets directly or indirectly affect the Company and that may or may not be financially recoverable; the co-operation of business partners especially where the Company is not operator of production projects or developments in which it has an interest; the inability to obtain regulatory approvals to operate existing properties or develop significant growth projects; risk associated with transportation of production or product to market or transportation of feedstock to processing facilities resulting from an interruption in pipeline and other transportation services both owned and contracted, due to calamitous event or regulatory obligation; and the inability to reach estimated production levels from existing and future oil and gas development projects as a result of technological or commercial difficulties; the continued availability of third-party owned equipment for operations; and
- with respect to the Company's Downstream operating segment: the costs to operate properties, plants and equipment in an efficient, reliable and safe manner; regulatory (environmental, licence to operate, social and political) and prevailing climatic conditions in the Company's operating locations; regulations to deal with climate change issues; the competitive actions of other companies, including increased competition from other oil and gas companies; business interruptions because of unexpected events such as fires, loss of containment, freeze-ups, equipment failures and other similar events affecting Husky or other parties whose operations or assets directly or indirectly affect the Company and that may or may not be financially recoverable; risk associated with transportation of production or product to market or transportation of feedstock to processing facilities resulting from an interruption in pipeline and other transportation services both owned and contracted, due to calamitous event or regulatory obligation; and the inability to obtain regulatory approvals to operate existing properties or develop significant growth projects.

These and other factors are discussed throughout this AIF and in the MD&A for the year ended December 31, 2017, which is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

In the discussions above, the Company has categorized some of the material factors and assumptions used to develop the forward-looking statements, and the risks, uncertainties and other factors that could influence actual results, by region, properties, plays and segments. These categories reflect the Company's current views regarding some of the factors, assumptions, risks and uncertainties most relevant to the particular region, property, play or segment. Other factors, assumptions, risks or uncertainties could impact a particular region, property, play or segment, and a factor, assumption, risk or uncertainty categorized under a particular region, property, play or segment could also influence results with respect to another region, property, play or segment.

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.

Non-GAAP Measures

This AIF contains the term "operating netback", which is a common non-GAAP metric used in the oil and gas industry. Management believes this measure 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.

Disclosure of 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" (or "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 and 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 reserve 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 and resources information in accordance with Canadian practices and specifically in accordance with National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, adopted by the Canadian securities regulators. Because the Company is permitted to prepare its reserves and resources 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 SEC.

All currency is expressed in Canadian dollars unless otherwise directed.

Husky Energy Inc.

Audit Committee Mandate

Purpose

The Audit Committee (the "Committee") is a committee of the Board of Directors (the "Board") of Husky Energy Inc. (the "Corporation"). The Committee's primary function is to assist the Board in carrying out its responsibilities with respect to:

1. the quarterly and annual financial statements and quarterly and annual MD&A, which are to be provided to shareholders and the appropriate regulatory agencies;
2. earnings press releases before the Corporation publicly discloses this information;
3. the system of internal controls that management has established;
4. the internal and external audit process;
5. the appointment of external auditors;
6. the appointment of qualified reserves evaluators or auditors;
7. the filing of statements and reports with respect to the Corporation's oil and gas reserves; and
8. the identification, management and mitigation of major financial risk exposures of the Corporation.

In addition, the Committee provides an avenue for communication between the Board and each of the Chief Financial Officer of the Corporation and other senior financial management, internal audit, the external auditors, external qualified reserves evaluators or auditors and internal qualified reserves evaluators. It is expected that the Committee will have a clear understanding with the external auditors and the external reserve evaluators or auditors that an open and transparent relationship must be maintained with the Committee.

While the Committee has the responsibilities and powers set forth in this Mandate, the role of the Committee is oversight. The members of the Committee are not full time employees of the Corporation and may or may not be accountants or auditors by profession or experts in the fields of accounting, or auditing and, in any event, do not serve in such capacity. Consequently, it is not the duty of the Committee to plan or conduct financial audits or reserve audits or evaluations, or to determine that the Corporation's financial statements are complete, accurate and are in accordance with applicable accounting or reserve principles.

This is the responsibility of management and the external auditors and, as to reserves, the external reserve evaluators or auditors. Management and the external auditors will also have the responsibility to conduct investigations and to assure compliance with laws and regulations and the Corporation's business conduct guidelines.

Composition

The Committee will consist of not less than three directors, all of whom will be independent and will satisfy the financial literacy requirements of securities regulatory requirements.

One of the members of the Committee will be an audit committee financial expert as defined in applicable securities regulatory requirements.

Members of the Committee will be appointed annually at a meeting of the Board, on the recommendation of the Corporate Governance Committee to the Co-Chairs of the Board and will be listed in the annual report to shareholders.

Committee members may be removed or replaced at any time by the Board, and will, in any event, cease to be a member of the Committee upon ceasing to be a member of the Board. Where a vacancy occurs at any time in the membership of the Committee, it may be filled by the Board.

The Committee Chair will be appointed by the Board, on the recommendation of the Corporate Governance Committee to the Co-Chairs of the Board.

Meetings

The Committee will meet at least four times annually on dates determined by the Chair or at the call of the Chair or any other Committee member, and as many additional times as the Committee deems necessary.

Committee members will strive to be present at all meetings either in person, by telephone or other communications facilities as permit all persons participating in the meeting to hear each other.

A majority of Committee members, present in person, by telephone, or by other permissible communication facilities will constitute a quorum.

The Committee will appoint a secretary, who need not be a member of the Committee, or a director of the Corporation. The secretary will keep minutes of the meetings of the Committee. Minutes will be sent to all Committee members, on a timely basis.

As necessary or desirable, but in any case at least quarterly, the Committee shall meet with members of management and representatives of the external auditors and internal audit in separate executive sessions to discuss any matters that the Committee or any of these groups believes should be discussed privately.

As necessary or desirable, but in any case at least annually, the Committee will meet the management and representatives of the external reserves evaluators or auditors and internal reserves evaluators in separate executive sessions to discuss matters that the Committee or any of these groups believes should be discussed privately.

Authority

Subject to any prior specific directive by the Board, the Committee is granted the authority to investigate any matter or activity involving financial accounting and financial reporting, the internal controls of the Corporation and the reporting of the Corporation's reserves and oil and gas activities.

The Committee has the authority to engage and set the compensation of independent counsel and other advisors, at the Corporation's expense, as it determines necessary to carry out its duties.

In recognition of the fact that the external auditors are ultimately accountable to the Committee, the Committee will have the authority and responsibility to recommend to the Board the external auditors that will be proposed for nomination at the annual general meeting. The external auditors will report directly to the Committee, and the Committee will evaluate and, where appropriate, replace the external auditors. The Committee will approve the fees and terms for all audit engagements and all non-audit engagements with the external auditors. The Committee will consult with management and the internal audit group regarding the engagement of the external auditors but will not delegate these responsibilities.

The external qualified reserves evaluators or auditors will report directly to the Committee, and the Committee will evaluate and, where appropriate, replace the external qualified reserves evaluators or auditors. The Committee will approve the fees and terms for all reserves evaluators or audit engagements. The Committee will consult with management and the internal qualified reserves evaluator's group regarding the engagement of the external qualified reserves evaluators or auditors but will not delegate these responsibilities.

Specific Duties & Responsibilities

The Committee will have the oversight responsibilities and specific duties as described below.

Audit

1. Review and reassess the adequacy of this Mandate annually and recommend any proposed changes to the Corporate Governance Committee and the Board for approval.
2. Review with the Corporation's management, internal audit and the external auditors and recommend to the Board for approval the Corporation's annual financial statements and annual MD&A which is to be provided to shareholders and the appropriate regulatory agencies and any financial statement contained in a prospectus, information circular, registration statement or other similar document.
3. Review with the Corporation's management, internal audit and the external auditors and approve the Corporation's quarterly financial statements and quarterly MD&A which is to be provided to shareholders and the appropriate regulatory agencies.
4. Review with the Corporation's management and approve earnings press releases before the Corporation publicly discloses this information.
5. Be responsible for the oversight of the work of the external auditors, including the resolution of disagreements between management of the Corporation and the external auditors regarding financial reporting.

6. Review with the Corporation's management, internal audit and the external auditors the Corporation's accounting and financial reporting controls and obtain annually, in writing from the external auditors their observations, if any, on material weaknesses in internal controls over financial reporting as noted during the course of their work.

7. Review with the Corporation's management, internal audit and the external auditors significant accounting and reporting principles, practices and procedures applied by the Corporation in preparing its financial statements, and discuss with the external auditors their judgments about the quality (not just the acceptability) of the Corporation's accounting principles used in financial reporting.

8. Review the scope of internal audit's work plan for the year and receive a summary report of major findings by internal audit and how management is addressing the conditions reported.

9. Review the scope and general extent of the external auditors' annual audit, such review to include an explanation from the external auditors of the factors considered in determining the audit scope, including the major risk factors, and the external auditor's confirmation whether or not any limitations have been placed on the scope or nature of their audit procedures.

10. Inquire as to the independence of the external auditors and obtain from the external auditors, at least annually, a formal written statement delineating all relationships between the external auditors and the Corporation as contemplated by Independence Standards Board Standard No. 1, Independence Discussions with Audit Committees.

11. Arrange with the external auditors that (a) they will advise the Committee, through its Chair and management of the Corporation, of any matters identified through procedures followed for the review of interim quarterly financial statements of the Corporation, such notification is to be made prior to the related press release and (b), for written confirmation at the end of each of the first three quarters of the year, that they have nothing to report to the Committee, if that is the case, or the written enumeration of required reporting issues.

12. Review at the completion of the annual audit, with senior management, internal audit and the external auditors the following:

    i. the annual financial statements and related footnotes and financial information to be included in the Corporation's annual report to shareholders;

    ii. results of the audit of the financial statements and the related report thereon and, if applicable, a report on changes during the year in accounting principles and their application;

    iii. significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit;

    iv. inquire about the cooperation received by the external auditors during their audit, including access to all requested records, data and information; and

    v. inquire of the external auditors whether there have been any material disagreements with management, which, if not satisfactorily resolved, would have caused them to issue a non-standard report on the Corporation's financial statements.

13. Discuss (a) with the external auditors, without management being present, (i) the quality of the Corporation's financial and accounting personnel, and (ii) the completeness and accuracy of the Corporation's financial statements, and (b) elicit the comments of senior management regarding the responsiveness of the external auditors to the Corporation's needs.

14. Meet with management to discuss any relevant significant recommendations that the external auditors may have, particularly those characterized as 'material' or 'serious' (typically, such recommendations will be presented by the external auditors in the form of a Letter of Comments and Recommendations to the Committee) and review the responses of management to the Letter of Comments and Recommendations and receive follow-up reports on action taken concerning the aforementioned recommendations.

15. Review and approve disclosures required to be included in periodic reports filed with Canadian and U.S. securities regulators with respect to non-audit services performed by the external auditors.

16. Establish adequate procedures for the review of the Corporation's disclosure of financial information extracted or derived from the Corporation's financial statements, and periodically assess the adequacy of those procedures.

17. Establish procedures for (a) the receipt, retention and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or auditing matters, and (b) the confidential, anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters.

18. Review and approve the Corporation's hiring policies regarding partners, employees and former partners and employees of the present and former external auditors.

19. Review the appointment and replacement of the senior internal audit executive.

20. Review with management, internal audit and the external auditors the methods used to establish and monitor the Corporation's policies with respect to unethical or illegal activities by the Corporation's employees that may have a material impact on the financial statements or other reporting of the Corporation.

21. Reviewing generally, as part of the review of the annual financial statements, a report, from the Corporation's general counsel concerning legal, regulatory and compliance matters that may have a material impact on the financial statements or other reporting of the Corporation.

22. Review and discuss with management, on a regular basis, the identification, management and mitigation of major financial risk exposures across the Corporation. In addition, the Committee oversees the Corporation's risk management framework and related processes.

Reserves

23. Review, with reasonable frequency, the Corporation's procedures relating to the disclosure of information with respect to the Corporation's oil and gas reserves, including the Corporation's procedures for complying with the disclosure requirements and restrictions of applicable regulatory requirements.

24. Review with management the appointment of the external qualified reserves evaluators or auditors, and in the case of any proposed change in such appointment, determine the reasons for the change and whether there have been disputes between management and the appointed external qualified reserves evaluators or auditors.

25. Review, with reasonable frequency, the Corporation's procedures for providing information to the external qualified reserves evaluators or auditors who report on reserves and data for the purposes of compliance with applicable securities regulatory requirements.

26. Meet, before the approval and release of the Corporation's reserves data and the report of the qualified reserve evaluators or auditors thereon, with senior management, the external qualified reserves evaluators or auditors and the internal qualified reserves evaluators to determine whether any restrictions affect their ability to report on reserves data without reservation and to review the reserves data and the report of the qualified reserves evaluators or auditors.

27. Recommend to the Board for approval of the content and filing of required statements and reports relating to the Corporation's disclosure of reserves data as prescribed by applicable regulatory requirements.

Miscellaneous

28. Review and approve (a) any change or waiver in the Corporation's Code of Business Conduct for the President and Chief Executive Officer and senior financial officers and (b) any public disclosure made regarding such change or waiver and, if satisfied, refer the matter to the Board for approval.

29. Act in an advisory capacity to the Board.

30. Carry out such other responsibilities as the Board may, from time to time, set forth.

31. Advise and report to the Co-Chairs of the Board and the Board, relative to the duties and responsibilities set out above, from time to time, and in such details as is reasonably appropriate.

Effective Date: May 6, 2014

Husky Energy Inc.

Report on Reserves Data by Internal Qualified Reserves Evaluator

To the Board of Directors of Husky Energy Inc. ("Husky"):

1. Our staff has evaluated Husky's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.
2. The reserves data are the responsibility of Husky's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.
3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter). Our internal reserves evaluators are not independent of Husky, within the meaning of the term "independent"under those standards.
4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with the principles and definitions presented in the COGE Handbook.
5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Husky evaluated for the year ended December 31, 2017, and identifies the respective portions thereof that we have evaluated and reported on to the Husky Audit Committee of the Board of Directors.

Internal Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate) Evaluated	
Husky	December 31, 2017	Canada	$	17,506 million
		China	$	4,404 million
		Indonesia	$	877 million
			$	22,787 million

6. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied.
7. We have no responsibility to update our reports referred to in paragraph 5 for events and circumstances occurring after the effective date of our report.
8. Because, the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.
9. I have signed this report in my capacity as an employee of Husky and not in my personal capacity.

/s/ Richard Leslie
Richard Leslie, P. Eng
Manager, Reserves
Calgary, Alberta
January 31, 2018

Husky Energy Inc.

Report of Management and Directors on Oil and Gas Disclosure

Management of Husky Energy Inc. ("Husky") is responsible for the preparation and disclosure of information with respect to Husky's oil and gas activities in accordance with securities regulatory requirements.This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.

Husky's oil and gas reserves evaluation process involves applying generally accepted procedures for the estimation of oil and gas reserves data for the purposes of complying with the legal requirements of National Instrument 51 101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Husky's Internal Qualified Reserves Evaluator is the Manager of Reserves, who is an employee of Husky and has evaluated Husky's oil and gas reserves data and certified that Husky's Reserves Data Process has been followed. The Report on Reserves Data by Husky's Internal Qualified Reserves Evaluator accompanies this report and will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the Board of Directors of Husky has:

a. reviewed Husky's procedures for providing information to the Internal Qualified Reserves Evaluator and the independent qualified external reserves auditor;

b. met with the Internal Qualified Reserves Evaluator and the independent qualified external reserves auditor to determine whether any restrictions affected the ability of the Internal Qualified Reserves Evaluator or the independent qualified external reserves auditor to report without reservation and, in the event of a proposal to change the independent qualified reserves auditor and evaluator, to inquire whether there had been disputes between the previous independent qualified reserves auditor and evaluator and management; and

c. reviewed the reserves data with management, the Internal Qualified Reserves Evaluator and the independent external reserves auditor.

The Audit Committee of the Board of Directors has reviewed Husky's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Audit Committee, approved:

a. the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;

b. the filing of Form 51-101F2, which is the Report on Reserves Data of Husky's Internal Qualified Reserves Evaluator; and

c. the content and filing of this report.

Husky sought and was granted by the Canadian Securities Administrators an exemption from the requirement under NI 51-101 to involve independent qualified oil and gas reserve evaluators or auditors. Notwithstanding this exemption, we involve independent qualified reserve auditors as part of Husky's corporate governance practices. Their involvement helps assure that our internal oil and gas reserve estimates are materially correct.

In Husky's view, the reliability of Husky's internally generated oil and gas reserves data is not materially less than would be afforded by Husky involving independent qualified reserves evaluators or independent qualified reserves auditors to evaluate or audit and review the reserves data. The primary factors supporting the involvement of independent qualified reserves evaluators or independent qualified reserves auditors apply when (i) their knowledge of, and experience with, a reporting issuer's reserves data are superior to that of the internal evaluators; and (ii) the work of the independent qualified reserves evaluator or independent qualified reserves auditors is significantly less likely to be adversely influenced by self-interest or management of the reporting issuer than the work of internal reserves evaluation staff. In Husky's view, neither of these factors applies in Husky's circumstances.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

/s/ Robert J. Peabody February 28, 2018
Robert J. Peabody
President & Chief Executive Officer

/s/ Robert W. P. Symonds February 28, 2018
Robert W. P. Symonds
Chief Operating Officer

/s/ William Shurniak February 28, 2018
William Shurniak
Director

/s/ Stephen E. Bradley February 28, 2018
Stephen E. Bradley
Director

Husky Energy Inc.

Independent Engineer's Audit Opinion

Husky Energy Inc.
707 - 8th Avenue S.W.
Calgary, Alberta
T2P 3G7

Attention: Mr. Richard Leslie, Manager Reserves

Re: Audit of Husky Energy Inc.'s 2017 Year-End Reserves

As requested by Husky Energy Inc. ("Husky" or the "Company"), Sproule has conducted an audit of Husky's reserves estimates and the respective net present values as at December 31, 2017. Husky internally evaluates all of their properties. Husky's detailed reserves information was provided to us for this audit. Sproule's responsibility is to express an independent opinion on the reasonableness of the reserves estimates and the respective net present value estimates, in the aggregate, based on our audit tests and to assess the quality of the Company's processes and guidelines applied in the preparation of the reserves information.

We conducted our audit in accordance with generally accepted audit standards as recommended by the Society of Petroleum Engineers and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") Volume 1 Section 12. As part of our audit, Sproule reviewed and assessed the policies, procedures, documentation and guidelines the Company has in place with respect to the estimation, review, documentation, and approval of Husky's reserves information. The audit included confirming on a test basis that there is adherence on the part of Husky's internal reserve evaluators and other employees to the reserves management and administration policies and procedures established by the Company. As well, the audit also included conducting reserves evaluation on a sufficient number of the Company's internally evaluated properties as considered necessary in order to express an opinion.

Based on the results of our audit, it is our opinion that Husky'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 COGE Handbook.

The results of the Husky internally generated reserves and net present values (based on forecast prices) supplied to us as part of the audit process are summarized below:

Husky Energy Inc.
Internally Evaluated Reserves and Net Present Values
Forecast Prices and Costs
As of December 31, 2017

	Working Interest Before Royalty Company Share of Remaining Reserves (mmboe)	Company Share of Net Present Value Before Income Tax (MM$) @ 10%
Total Proved	1,301	12,812
Total Proved Plus Probable	2,437	22,787

Sincerely,

Sproule Associates Limited

/s/ Cameron P. Six, P. Eng.
Cameron P. Six, P. Eng.
President and Chief Executive Officer
Calgary, Alberta
January 31, 2018

Document B
Form 40-F

Consolidated Financial Statements and Auditors' Report to Shareholders

For the Year Ended December 31, 2017

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Husky Energy Inc.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated financial statements of Husky Energy Inc. (the “Company”), which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of income, comprehensive income, changes in shareholders’ equity and cash flows for the years then ended, and the related notes, comprising a summary of significant accounting policies and other explanatory information (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of the Company as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

Report on Internal Control Over Financial Reporting

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (“PCAOB”), the Company’s internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2018 expressed an unqualified (unmodified) opinion on the effectiveness of the Company’s internal control over financial reporting.

Basis for Opinion

A - Management’s Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

B - Auditors’ Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards and the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement, whether due to error or fraud. Those standards also require that we comply with ethical requirements, including independence. We are required to be independent with respect to the Company in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada, the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB. We are a public accounting firm registered with the PCAOB.

An audit includes performing procedures to assess the risks of material misstatements of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included obtaining and examining, on a test basis, audit evidence regarding the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to Company’s preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances.

An audit also includes evaluating the appropriateness of accounting policies and principles used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a reasonable basis for our audit opinion.

/s/ KPMG LLP
KPMG LLP

We have served as the Company’s auditor since 1951.

Chartered Professional Accountants
Calgary, Canada
February 28, 2018

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Husky Energy Inc.

Opinion on Internal Control Over Financial Reporting

We have audited Husky Energy Inc.'s (the "Company") internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2017, based on the criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Report on the Consolidated Financial Statements

We also have audited, in accordance with Canadian generally accepted auditing standards and the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company, which comprise the consolidated balance sheets as at December 31, 2017 and 2016, the consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for the years then ended, and the related notes (collectively referred to as the "consolidated financial statements") and our report dated February 28, 2018 expressed an unmodified (unqualified) opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Annual Report on Internal Control over Financial Reporting included in Management's Discussion and Analysis. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB and in accordance with the ethical requirements that are relevant to our audit of the consolidated financial statements in Canada.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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

/s/ KPMG LLP
KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 28, 2018

MANAGEMENT'S REPORT

The management of Husky Energy Inc. ("the Company") is responsible for the financial information and operating data presented in this financial document.

The consolidated financial statements have been prepared by management in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board. When alternative accounting methods exist, management has chosen those it deems most appropriate in the circumstances. Financial statements are not precise as they include certain amounts based on estimates and judgments. Management has determined such amounts on a reasonable basis in order to ensure that the financial statements are presented fairly, in all material respects. Financial information presented elsewhere in this financial document has been prepared on a basis consistent with that in the consolidated financial statements.

The Company maintains systems of internal accounting and administrative controls. These systems are designed to provide reasonable assurance that the financial information is relevant, reliable and accurate and that the Company's assets are properly accounted for and adequately safeguarded. Management's evaluation concluded that the Company's internal control over financial reporting was effective as of December 31, 2017. The system of internal controls is further supported by an internal audit function.

The Audit Committee of the Board of Directors, composed of independent non-management directors, meets regularly with management, internal auditors as well as the external auditors, to discuss audit (external, internal and joint venture), internal controls, accounting policy and financial reporting matters as well as the reserves determination process. The Committee reviews the annual consolidated financial statements with both management and the independent auditors and reports its findings to the Board of Directors before such statements are approved by the Board. The Committee is also responsible for the appointment of the external auditors for the Company.

The consolidated financial statements have been audited by KPMG LLP, the independent auditors, in accordance with Canadian Auditing Standards and the standards of the Public Company Accounting Oversight Board (United States) on behalf of the shareholders. KPMG LLP has full and free access to the Audit Committee.

"Robert J. Peabody"

Robert J. Peabody

President & Chief Executive Officer

"Jonathan M. McKenzie"

Jonathan M. McKenzie

Chief Financial Officer

Calgary, Canada
February 28, 2018

INDEPENDENT AUDITOR'S REPORT

To the Shareholders and the Board of Directors of Husky Energy Inc.

We have audited the accompanying consolidated financial statements of Husky Energy Inc., which comprise the consolidated balance sheets as at December 31, 2017 and December 31, 2016, the consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the consolidated financial position of Husky Energy Inc. as at December 31, 2017 and December 31, 2016, and its consolidated financial performance and its consolidated cash flows for the years then ended in accordance with International Financial Reporting Standards as issued by the International Accounting Standards Board.

/s/ KPMG LLP
KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 28, 2018

Consolidated Balance Sheets

(millions of Canadian dollars)	**December 31, 2017**	December 31, 2016
Assets		
Current assets		
Cash and cash equivalents *(note 4)*	**2,513**	1,319
Accounts receivable *(notes 5, 24)*	**1,186**	1,036
Income taxes receivable	**164**	186
Inventories *(note 6)*	**1,513**	1,558
Prepaid expenses	**145**	135
Restricted cash *(notes 7, 16)*	**95**	84
	5,616	4,318
Restricted cash *(note 7, 16)*	**97**	72
Exploration and evaluation assets *(note 8)*	**838**	1,066
Property, plant and equipment, net *(note 9)*	**24,078**	24,593
Goodwill *(note 10)*	**633**	679
Investment in joint ventures *(note 11)*	**1,238**	1,128
Long-term income taxes receivable	**242**	232
Other assets *(note 12)*	**185**	172
Total Assets	**32,927**	32,260
Liabilities and Shareholders' Equity		
Current liabilities		
Accounts payable and accrued liabilities *(note 14)*	**3,033**	2,226
Short-term debt *(note 15)*	**200**	200
Long-term debt due within one year *(note 15)*	**—**	403
Contribution payable due within one year *(note 11)*	**—**	146
Asset retirement obligations *(note 16)*	**274**	218
	3,507	3,193
Long-term debt *(note 15)*	**5,240**	4,736
Other long-term liabilities *(note 17)*	**1,237**	1,020
Asset retirement obligations *(note 16)*	**2,252**	2,573
Deferred tax liabilities *(note 18)*	**2,724**	3,111
Total Liabilities	**14,960**	14,633
Shareholders' equity		
Common shares *(note 19)*	**7,293**	7,296
Preferred shares *(note 19)*	**874**	874
Contributed surplus	**2**	—
Retained earnings	**9,207**	8,457
Accumulated other comprehensive income	**580**	989
Non-controlling interest	**11**	11
Total Shareholders' Equity	**17,967**	17,627
Total Liabilities and Shareholders' Equity	**32,927**	32,260

The accompanying notes to the consolidated financial statements are an integral part of these statements.

On behalf of the Board:

"Robert J. Peabody"
Robert J. Peabody
Director

"William Shurniak"
William Shurniak
Director

Consolidated Statements of Income

(millions of Canadian dollars, except share data)	Year ended December 31, **2017**	2016
Gross revenues	**18,986**	13,312
Royalties	**(363)**	(305)
Marketing and other	**(40)**	(88)
Revenues, net of royalties	**18,583**	12,919
Expenses		
Purchases of crude oil and products	**11,566**	7,356
Production, operating and transportation expenses *(note 20)*	**2,679**	2,724
Selling, general and administrative expenses *(note 20)*	**650**	544
Depletion, depreciation, amortization and impairment *(notes 9, 10)*	**2,882**	2,462
Exploration and evaluation expenses *(note 8)*	**146**	188
Gain on sale of assets *(note 9)*	**(46)**	(1,634)
Other – net	**(18)**	(27)
	17,859	11,613
Earnings from operating activities	**724**	1,306
Share of equity investment gain *(note 11)*	**61**	15
Financial items *(note 21)*		
Net foreign exchange gains (losses)	**(6)**	13
Finance income	**37**	17
Finance expenses	**(392)**	(401)
	(361)	(371)
Earnings before income taxes	**424**	950
Provisions for (recovery of) income taxes *(note 18)*		
Current	**(3)**	(1)
Deferred	**(359)**	29
	(362)	28
Net earnings	**786**	922
Earnings per share *(note 19)*		
Basic	**0.75**	0.88
Diluted	**0.75**	0.88
Weighted average number of common shares outstanding *(note 19)*		
Basic *(millions)*	**1,005.3**	1,004.9
Diluted *(millions)*	**1,005.3**	1,004.9

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Comprehensive Income

(millions of Canadian dollars)	Year ended December 31, 2017	2016
Net earnings	**786**	922
Other comprehensive loss		
Items that will not be reclassified into earnings, net of tax:		
Remeasurements of pension plans *(note 22)*	**(7)**	(18)
Items that may be reclassified into earnings, net of tax:		
Derivatives designated as cash flow hedges *(note 24)*	**(2)**	(2)
Equity investment – share of other comprehensive income	**3**	2
Exchange differences on translation of foreign operations	**(653)**	(247)
Hedge of net investment *(note 24)*	**243**	113
Other comprehensive loss	**(416)**	(152)
Comprehensive income	**370**	770

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Changes in Shareholders' Equity

(millions of Canadian dollars)	Attributable to Equity Holders							
					AOCI [1]			
	Common Shares	Preferred Shares	Contributed Surplus	Retained Earnings	Foreign Currency Translation	Hedging	Non-Controlling Interest	Total Shareholders' Equity
Balance as at December 31, 2015	7,000	874	—	7,589	1,103	20	—	16,586
Net earnings	—	—		922	—	—	—	922
Other comprehensive income (loss)								
Remeasurements of pension plans (net of tax recovery of $6 million) *(notes 18, 22)*	—	—	—	(18)	—	—	—	(18)
Derivatives designated as cash flow hedges (net of tax recovery of less than $1 million) *(notes 18, 24)*	—	—	—	—	—	(2)	—	(2)
Equity investment - share of other comprehensive income	—	—	—	—	—	2	—	2
Exchange differences on translation of foreign operations (net of tax recovery of $40 million) *(note 18)*	—	—	—	—	(247)	—	—	(247)
Hedge of net investment (net of tax loss of $17 million) *(notes 18, 24)*	—	—	—	—	113	—	—	113
Total comprehensive income (loss)	—	—	—	904	(134)	—	—	770
Transactions with owners recognized directly in equity:								
Stock dividends paid *(note 19)*	296	—		—	—	—	—	296
Dividends declared on preferred shares *(note 19)*	—	—		(36)	—	—	—	(36)
Non-controlling interest	—	—	—	—	—	—	11	11
Balance as at December 31, 2016	7,296	874	—	8,457	969	20	11	17,627
Net earnings	**—**	**—**		**786**	**—**	**—**	**—**	**786**
Other comprehensive income (loss)								
Remeasurements of pension plans (net of tax recovery of $4 million) *(notes 18, 22)*	—	—		**(7)**	—	—	—	**(7)**
Derivatives designated as cash flow hedges (net of tax expense of less than $1 million) *(notes 18, 24)*	—	—		—	—	**(2)**	—	**(2)**
Equity investment - share of other comprehensive income	—	—		—	—	**3**	—	**3**
Exchange differences on translation of foreign operations (net of tax recovery of $82 million) *(note 18)*	—	—		—	**(653)**	—	—	**(653)**
Hedge of net investment (net of tax loss of $38 million) *(notes 18, 24)*	—	—		—	**243**	—	—	**243**
Total comprehensive income (loss)	**—**	**—**	**—**	**779**	**(410)**	**1**	**—**	**370**
Transactions with owners recognized directly in equity:								
Dividends declared on preferredshares *(note 19)*	—	—	—	**(34)**	—	—	—	**(34)**
Share cancellation *(note 19)*	(3)	—	2	**5**	—	—	—	**4**
Balance as at December 31, 2017	**7,293**	**874**	**2**	**9,207**	**559**	**21**	**11**	**17,967**

(1) *Accumulated other comprehensive income.*

The accompanying notes to the consolidated financial statements are an integral part of these statements.

Consolidated Statements of Cash Flows

(millions of Canadian dollars)	Year ended December 31, 2017	2016
Operating activities		
Net earnings	**786**	922
Items not affecting cash:		
Accretion *(note 21)*	**112**	126
Depletion, depreciation, amortization and impairment *(note 9)*	**2,882**	2,462
Inventory write-down to net realizable value *(note 6)*	**—**	9
Exploration and evaluation expenses *(note 8)*	**6**	86
Deferred income taxes *(note 18)*	**(359)**	29
Foreign exchange	**(4)**	(4)
Stock-based compensation *(notes 19, 20)*	**45**	33
Gain on sale of assets *(note 9)*	**(46)**	(1,634)
Unrealized mark to market loss	**56**	38
Share of equity investment gain *(note 11)*	**(61)**	(15)
Other	**16**	24
Settlement of asset retirement obligations *(note 16)*	**(136)**	(87)
Deferred revenue *(note 17)*	**(16)**	209
Distribution from joint ventures *(note 11)*	**25**	—
Change in non-cash working capital *(note 23)*	**398**	(227)
Cash flow – operating activities	**3,704**	1,971
Financing activities		
Long-term debt issuance *(note 15)*	**750**	6,181
Long-term debt repayment *(note 15)*	**(365)**	(6,949)
Short-term debt repayment *(note 15)*	**—**	(520)
Debt issue costs *(note 15)*	**(6)**	—
Dividends on preferred shares *(note 19)*	**(34)**	(27)
Other	**18**	21
Change in non-cash working capital *(note 23)*	**—**	(68)
Cash flow – financing activities	**363**	(1,362)
Investing activities		
Capital expenditures	**(2,220)**	(1,705)
Corporate acquisition *(note 9)*	**(670)**	—
Proceeds from asset sales *(note 9)*	**192**	2,935
Contribution payable payment *(note 11)*	**(142)**	(193)
Contribution to joint ventures *(note 11)*	**(81)**	(102)
Other	**(40)**	(30)
Change in non-cash working capital *(note 23)*	**172**	(273)
Cash flow – investing activities	**(2,789)**	632
Increase in cash and cash equivalents	**1,278**	1,241
Effect of exchange rates on cash and cash equivalents	**(84)**	8
Cash and cash equivalents at beginning of year	**1,319**	70
Cash and cash equivalents at end of year	**2,513**	1,319
Supplementary Cash Flow Information		
Net interest paid	**(334)**	(344)
Income taxes received	**41**	3

The accompanying notes to the consolidated financial statements are an integral part of these statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

Note 1 Description of Business and Segmented Disclosures

Husky Energy Inc. ("Husky" or "the Company") is an international integrated energy company incorporated under the Business Corporations Act (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, Cumulative Redeemable Preferred Shares, Series 2, Cumulative Redeemable Preferred Shares, Series 3, Cumulative Redeemable Preferred Shares, Series 5 and Cumulative Redeemable Preferred Shares, 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 registered office is located at 707, 8th Avenue S.W., PO Box 6525, Station D, Calgary, Alberta, T2P 3G7.

Management has identified segments for the Company's business based on differences in products, services and management responsibility. The Company's business is conducted predominantly through two major business segments – Upstream and Downstream.

Upstream operations in the Integrated Corridor and Offshore include exploration for, and development and production of, crude oil, bitumen, natural gas and natural gas liquids ("NGL") ("Exploration and Production") and marketing of the Company's and other producers' crude oil, natural gas, NGLs, 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 Alberta, Saskatchewan, and British Columbia ("Western Canada"), offshore east coast of Canada ("Atlantic") and offshore China and offshore Indonesia ("Asia Pacific").

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 asphalt, gasoline, jet fuel and diesel fuels 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.

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[(1)]		Infrastructure and Marketing[(2)]		Total	
Year ended December 31,	**2017**	2016	**2017**	2016	**2017**	2016
Gross revenues	**4,978**	4,036	**1,976**	955	**6,954**	4,991
Royalties	**(363)**	(305)	**—**	—	**(363)**	(305)
Marketing and other	**—**	—	**(40)**	(88)	**(40)**	(88)
Revenues, net of royalties	**4,615**	3,731	**1,936**	867	**6,551**	4,598
Expenses						
Purchases of crude oil and products	**—**	32	**1,855**	857	**1,855**	889
Production, operating and transportation expenses	**1,650**	1,760	**13**	20	**1,663**	1,780
Selling, general and administrative expenses	**265**	232	**4**	5	**269**	237
Depletion, depreciation, amortization and impairment	**2,237**	1,815	**2**	13	**2,239**	1,828
Exploration and evaluation expenses	**146**	188	**—**	—	**146**	188
Loss (gain) on sale of assets	**(42)**	(192)	**1**	(1,439)	**(41)**	(1,631)
Other – net	**6**	53	**(8)**	(3)	**(2)**	50
	4,262	3,888	**1,867**	(547)	**6,129**	3,341
Earnings (loss) from operating activities	**353**	(157)	**69**	1,414	**422**	1,257
Share of equity investment gain (loss)	**12**	(1)	**49**	16	**61**	15
Financial items						
Net foreign exchange gain (loss)	**—**	—	**—**	—	**—**	—
Finance income	**5**	5	**—**	—	**5**	5
Finance expenses	**(131)**	(145)	**—**	—	**(131)**	(145)
	(126)	(140)	**—**	—	**(126)**	(140)
Earnings (loss) before income taxes	**239**	(298)	**118**	1,430	**357**	1,132
Provisions for (recovery of) income taxes						
Current	**(34)**	(100)	**—**	—	**(34)**	(100)
Deferred	**99**	19	**32**	122	**131**	141
	65	(81)	**32**	122	**97**	41
Net earnings (loss)	**174**	(217)	**86**	1,308	**260**	1,091
Intersegment revenues	**1,250**	988	**—**	—	**1,250**	988

(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) *Includes $280 million of revenue (2016 - nil) and $234 million of associated costs (2016 - nil) for construction contracts, inclusive of $259 million of revenue (2016 - nil) and $236 million of costs (2016 - nil) for contracts in progress accounted for under the percentage of completion method.*

(3) *Eliminations relate to sales and operating revenues between segments recorded at transfer prices based on current market prices. Segment results include transactions between business segments.*

Downstream								Corporate and Eliminations[3]		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2017	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
1,440	1,324	**2,787**	2,301	**9,355**	5,995	**13,582**	9,620	**(1,550)**	(1,299)	**18,986**	13,312
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**(363)**	(305)
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**(40)**	(88)
1,440	1,324	**2,787**	2,301	**9,355**	5,995	**13,582**	9,620	**(1,550)**	(1,299)	**18,583**	12,919
983	808	**2,219**	1,770	**8,059**	5,188	**11,261**	7,766	**(1,550)**	(1,299)	**11,566**	7,356
197	168	**256**	241	**563**	535	**1,016**	944	**—**	—	**2,679**	2,724
9	4	**53**	43	**15**	13	**77**	60	**304**	247	**650**	544
99	103	**111**	102	**354**	342	**564**	547	**79**	87	**2,882**	2,462
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**146**	188
—	—	**(5)**	(3)	**—**	—	**(5)**	(3)	**—**	—	**(46)**	(1,634)
—	(1)	**(1)**	(10)	**(21)**	(176)	**(22)**	(187)	**6**	110	**(18)**	(27)
1,288	1,082	**2,633**	2,143	**8,970**	5,902	**12,891**	9,127	**(1,161)**	(855)	**17,859**	11,613
152	242	**154**	158	**385**	93	**691**	493	**(389)**	(444)	**724**	1,306
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**61**	15
—	—	**—**	—	**—**	—	**—**	—	**(6)**	13	**(6)**	13
—	—	**—**	—	**—**	—	**—**	—	**32**	12	**37**	17
(1)	(1)	**(12)**	(7)	**(14)**	(3)	**(27)**	(11)	**(234)**	(245)	**(392)**	(401)
(1)	(1)	**(12)**	(7)	**(14)**	(3)	**(27)**	(11)	**(208)**	(220)	**(361)**	(371)
151	241	**142**	151	**371**	90	**664**	482	**(597)**	(664)	**424**	950
63	—	**45**	—	**2**	—	**110**	—	**(79)**	99	**(3)**	(1)
(22)	66	**(7)**	41	**135**	33	**106**	140	**(596)**	(252)	**(359)**	29
41	66	**38**	41	**137**	33	**216**	140	**(675)**	(153)	**(362)**	28
110	175	**104**	110	**234**	57	**448**	342	**78**	(511)	**786**	922
192	157	**108**	154	**—**	—	**300**	311	**—**	—	**1,550**	1,299

Segmented Financial Information

($ millions)	Upstream					
	Exploration and Production[(1)]		Infrastructure and Marketing		Total	
Year ended December 31,	**2017**	2016	**2017**	2016	**2017**	2016
Expenditures on exploration and evaluation assets[(2)]	**148**	46	**—**	—	**148**	46
Expenditures on property, plant and equipment[(2)]	**1,328**	826	**—**	54	**1,328**	880
As at December 31,						
Exploration and evaluation assets	**838**	1,066	—	—	**838**	1,066
Developing and producing assets at cost	**41,804**	44,790	—	—	**41,804**	44,790
Accumulated depletion, depreciation, amortization and impairment	**(26,014)**	(27,984)	**—**	—	**(26,014)**	(27,984)
Other property, plant and equipment at cost	**—**	—	**89**	140	**89**	140
Accumulated depletion, depreciation and amortization	**—**	—	**(50)**	(99)	**(50)**	(99)
Total exploration and evaluation assets and property, plant and equipment, net	**16,628**	17,872	**39**	41	**16,667**	17,913
Total assets	**17,920**	19,098	**1,364**	1,582	**19,284**	20,680

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

Geographical Financial Information

($ millions)	**Canada**		**United States**	
Year ended December 31,	**2017**	2016	**2017**	2016
Gross revenues[(1)]	**8,599**	6,510	**9,355**	5,995
Royalties	**(303)**	(261)	**—**	—
Marketing and other	**(40)**	(88)	**—**	—
Revenue, net of royalties	**8,256**	6,161	**9,355**	5,995
As at December 31,				
Restricted cash – non-current	**—**	—	**—**	—
Exploration and evaluation assets	**831**	654	**—**	—
Property, plant and equipment, net	**15,478**	16,112	**5,595**	5,341
Goodwill	**—**	—	**633**	679
Investment in joint ventures	**685**	640	**—**	—
Long-term income tax receivable	**242**	232	**—**	—
Other assets	**64**	43	**21**	23
Total non-current assets	**17,300**	17,681	**6,249**	6,043

(1) *Sales to external customers are based on the location of the seller.*

Downstream								Corporate and Eliminations		Total	
Upgrading		Canadian Refined Products		U.S. Refining and Marketing		Total					
2017	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**148**	46
230	51	**87**	52	**313**	623	**630**	726	**114**	53	**2,072**	1,659
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**838**	1,066
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**41,804**	44,790
—	—	**—**	—	**—**	—	**—**	—	**—**	—	**(26,014)**	(27,984)
2,600	2,367	**2,704**	2,500	**8,300**	7,897	**13,604**	12,764	**1,124**	1,011	**14,817**	13,915
(1,463)	(1,363)	**(1,466)**	(1,344)	**(2,705)**	(2,556)	**(5,634)**	(5,263)	**(845)**	(766)	**(6,529)**	(6,128)
1,137	1,004	**1,238**	1,156	**5,595**	5,341	**7,970**	7,501	**279**	245	**24,916**	25,659
1,263	1,076	**1,548**	1,410	**7,580**	7,017	**10,391**	9,503	**3,252**	2,077	**32,927**	32,260

China		**Other International**		**Total**	
2017	2016	**2017**	2016	**2017**	2016
1,032	807	**—**	—	**18,986**	13,312
(60)	(44)	**—**	—	**(363)**	(305)
—	—	**—**	—	**(40)**	(88)
972	763	**—**	—	**18,583**	12,919
97	72	**—**	—	**97**	72
3	407	**4**	5	**838**	1,066
3,005	3,139	**—**	1	**24,078**	24,593
—	—	**—**	—	**633**	679
—	—	**553**	488	**1,238**	1,128
—	—	**—**	—	**242**	232
78	83	**22**	23	**185**	172
3,183	3,701	**579**	517	**27,311**	27,942

Note 2 Basis of Presentation

a) Basis of Measurement and Statement of Compliance

The consolidated financial statements have been prepared by management on a historical cost basis with some exceptions, as detailed in the accounting policies set out below in accordance with International Financial Reporting Standards ("IFRS"), as issued by the International Accounting Standards Board ("IASB"). These accounting policies have been applied consistently for all periods presented in these consolidated financial statements.

These consolidated financial statements were approved and signed by the Chair of the Audit Committee and the Chief Executive Officer on February 28, 2018 having been duly authorized to do so by the Board of Directors.

Certain prior years' amounts have been reclassified to conform with current presentation.

b) Principles of Consolidation

The consolidated financial statements include the accounts of Husky Energy Inc. and its subsidiaries. Subsidiaries are defined as any entities, including unincorporated entities such as partnerships, for which the Company has the power to govern their financial and operating policies to obtain benefits from their activities. The Company's accounts reflect the proportionate share of the assets, liabilities, revenues, expenses and cash flows from the Company's activities that are conducted jointly with third parties. Intercompany balances, net earnings and unrealized gains and losses arising from intercompany transactions are eliminated in preparing the consolidated financial statements. A portion of the Company's activities relate to joint ventures (see Note 11), which are accounted for using the equity method.

c) Use of Estimates, Judgments and Assumptions

The timely preparation of the consolidated financial statements requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies, if any,as at the date of the financial statements and the reported amounts of revenue and expenses during the period. Actual results may differ from these estimates, judgments and assumptions.

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.

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 cash generating units ("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.

Significant estimates, judgments and assumptions made by management in the preparation of these consolidated financial statements are outlined in detail in Note 3.

d) Functional and Presentation Currency

The consolidated financial statements are presented in Canadian dollars, which is the Company's functional currency. All financial information is presented in millions of Canadian dollars, except per share amounts and unless otherwise stated.

The designation of the Company's functional currency is a management judgment based on the currency of the primary economic environment in which the Company operates.

Note 3 Significant Accounting Policies

a) Cash and Cash Equivalents

Cash and cash equivalents consist of cash on hand less outstanding cheques and deposits with an original maturity of less than three months at the time of purchase. When outstanding cheques are in excess of cash on hand and short-term deposits, and the Company has the ability to net settle, the excess is reported in bank operating loans.

Cash and cash equivalents held that are not available for use are classified as restricted cash. When restricted cash is not expected to be used within 12 months, it is classified as a non-current asset.

b) Inventories

Crude oil, natural gas, refined petroleum products and sulphur inventories are valued at the lower of cost or net realizable value. Cost is determined using average cost or on a first-in, first-out basis, as appropriate. Materials, parts and supplies are valued at the lower of average cost or net realizable value. Cost consists of raw material, labour, direct overhead, operating costs, transportation and depreciation, depletion and amortization. Commodity inventories held for trading purposes are carried at fair value and measured at fair value less costs to sell based on Level 2 observable inputs, refer to policy Note 3 (m). Any changes in commodity inventory fair value are included as gains or losses in marketing and other in the consolidated statements of income, during the period of change. Previous inventory impairment provisions are reversed when there is a change in the condition that caused the impairment and the inventory remains on hand. Unrealized intersegment net earnings on inventory sales are eliminated.

c) Precious Metals

The Company uses precious metals in conjunction with a catalyst as part of the downstream upgrading and refining processes. These precious metals remain intact; however, there is a loss during the reclamation process. The estimated loss is amortized to production and operating expenses over the period that the precious metal is in use, which is approximately two to five years. After the reclamation process, the actual loss is compared to the estimated loss and any difference is recognized in net earnings. Precious metals are included in other assets on the balance sheet.

d) Exploration and Evaluation Assets and Property, Plant and Equipment

i) Cost

Oil and gas properties and other property, plant and equipment are recorded at cost, including expenditures that are directly attributable to the purchase or development of an asset. Borrowing costs directly attributable to the acquisition, construction or production of a qualifying asset are included in the asset cost. Capitalization ceases when substantially all activities necessary to prepare the qualifying asset for its intended use are complete.

ii) Exploration and evaluation costs

The accounting treatment of costs incurred for oil and natural gas exploration, evaluation and development is determined by the classification of the underlying activities as either exploratory or developmental. The results from an exploration drilling program can take considerable time to analyze, and the determination that commercial reserves have been discovered requires determination of technical feasibility, commercial viability and industry experience. Exploration activities can fluctuate from year to year, due to such factors as the level of exploratory spending, the level of risk sharing with third parties participating in exploratory drilling and the degree of risk associated with drilling in particular areas. Properties that are assumed to be productive may, over a period of time, actually deliver oil and gas in quantities different than originally estimated because of changes in reservoir performance.

Costs incurred after the legal right to explore an area has been obtained and before technical feasibility and commercial viability of the area have been established are capitalized as exploration and evaluation assets. These costs include costs to acquire acreage and exploration rights, legal and other professional fees and land brokerage fees. Pre-license costs and geological and geophysical costs associated with exploration activities are expensed in the period incurred. Costs directly associated with an exploration well are initially capitalized as an exploration and evaluation asset until the drilling of the well is complete and the results have been evaluated. If extractable hydrocarbons are found and are likely to be developed commercially, but are subject to further appraisal activity, which may include the drilling of wells, the costs continue to be carried as an exploration and evaluation asset while sufficient and continued progress is made in assessing the commercial viability of the hydrocarbons. Capitalized exploration and evaluation costs or assets are not depreciated and are carried forward until technical feasibility and commercial viability of the area is determined or the assets are determined to be impaired. Management determines technical feasibility and commercial viability when exploration and evaluation assets are reclassified to property, plant and equipment. This decision considers several factors, including the existence of reserves, establishing commercial and technical feasibility and whether the asset can be developed using a proved development concept and has received internal approval. Upon the determination of technical feasibility and commercial viability, capitalized exploration and evaluation assets are then transferred to property, plant and equipment. All such carried costs are subject to technical, commercial and management review, as well as review for impairment indicators, at least every reporting period to confirm the continued intent to develop or otherwise extract value from the discovery. These costs are also tested for impairment when transferred to property, plant and equipment. Capitalized exploration and evaluation expenditures related to wells that do not find reserves, or where no future activity is planned, are expensed as exploration and evaluation expenses.

The application of the Company's accounting policy for exploration and evaluation costs requires judgment in determining whether it is likely that future economic benefit exists when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined. Judgments may change as new information becomes available.

iii) Development costs

Expenditures, including borrowing costs, on the construction, installation and completion of infrastructure facilities, such as platforms, pipelines and the drilling of development wells, are capitalized as oil and gas properties. Costs incurred to operate and maintain wells and equipment to lift oil and gas to the surface are expensed as production and operating expenses.

iv) Other property, plant and equipment

Repair and maintenance costs, other than major turnaround costs, are expensed as incurred. Major turnaround costs are capitalized as part of property, plant and equipment when incurred and are amortized over the estimated period of time to the anticipated date of the next turnaround.

v) Depletion, depreciation and amortization

Oil and gas properties are depleted on a unit-of-production basis over the proved developed reserves of the particular field, 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. The unit-of-production rate for the depletion of oil and gas properties related to total proved plus probable reserves takes into account expenditures incurred to date together with sanctioned future development expenditures required to develop the field.

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.

Depreciation for substantially all other property, plant and equipment is provided using the straight-line method based on the estimated useful lives of assets, which range from five to forty-five years, less any estimated residual value. The useful lives of assets are estimated based upon the period the asset is expected to be available for use by the Company. Residual values are based upon the estimated amount that would be obtained on disposal, net of any costs associated with the disposal. Other property, plant and equipment held under finance leases are depreciated over the shorter of the lease term and the estimated useful life of the asset.

Depletion, depreciation and amortization rates for all capitalized costs associated with the Company's activities are reviewed at least annually, or when events or conditions occur that impact capitalized costs, reserves and estimated service lives.

vi) Finance Leases

Finance leases, which transfer substantially all of the risks and rewards incidental to ownership of the leased item to the Company, are capitalized at the commencement of the lease term at the fair value of the lease property or, if lower, at the present value of the minimum lease payments. Capitalized leased assets are depreciated over the shorter of the estimated useful life of the asset or the lease term.

All other leases are accounted for as operating leases and the lease costs are expensed as incurred.

e) 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.

For a joint operation, the consolidated financial statements include the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flows of the joint arrangement. The Company reports items of a similar nature to those on the financial statements of the joint arrangement, on a line-by-line basis, from the date that joint control commences until the date that joint control ceases.

Joint ventures are accounted for using the equity method of accounting and recognized at cost and adjusted thereafter for the post-acquisition change in the Company's share of the joint venture's net assets. The Company's consolidated financial statements include its share of the joint venture's profit or loss and other comprehensive income ("OCI") included in investment in joint ventures, until the date that joint control ceases.

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.

f) Investments in Associates

An associate is an entity for which the Company has significant influence and thereby has the power to participate in the financial and operational decisions but does not control or jointly control the investee. Investments in associates are accounted for using the equity method of accounting and are recognized at cost and adjusted thereafter for the post-acquisition change in the Company's share of the investee's net assets. The Company's consolidated financial statements include its share of the investee's profit or loss and OCI until the date that significant influence ceases.

g) Business Combinations

Business combinations are accounted for using the acquisition method. Determining whether an acquisition meets the definition of a business combination or represents an asset purchase requires judgment on a case-by-case basis. If the acquisition meets the definition of a business combination, the assets and liabilities are recognized based on the contractual terms, economic conditions, the Company's operating and accounting policies and other factors that exist on the acquisition date, which is the date on which control is transferred to the Company. The identifiable assets and liabilities are measured at their fair values on the acquisition date with limited exceptions. Any additional consideration payable, contingent upon the occurrence of a future event, is recognized at fair value on the acquisition date; subsequent changes in the fair value of the liability are recognized in net earnings. Acquisition costs incurred are expensed and included in selling, general and administrative expenses in the consolidated statements of income.

h) Goodwill

Goodwill is the excess of the purchase price paid over the recognized amount of net assets acquired through business combinations, which is inherently imprecise as judgment is required in the determination of the fair value of assets and liabilities. Goodwill, which is not amortized, is assigned to appropriate CGUs or groups of CGUs. Goodwill is tested for impairment annually and when circumstances indicate that the carrying value may be impaired. Impairment losses are recognized in net earnings and are not subject to reversal. On the disposal or termination of a previously acquired business, any remaining balance of associated goodwill is included in the determination of the gain or loss on disposal.

i) Impairment and Reversals of Impairment on Non-Financial Assets

The carrying amounts of the Company's non-financial assets, other than inventories and deferred tax assets, are reviewed at the end of each reporting period to determine whether there is an indication of impairment or reversal of impairment. If such indication exists, the recoverable amount is estimated.

Determining whether there are any indications of impairment or impairment reversals 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 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 impact on the Company's CGUs. If any indication of impairment or impairment reversals exist, an estimate of the asset's recoverable amount is calculated as the higher of the fair value less costs to sell ("FVLCS") and the asset's value in use ("VIU") for an individual asset or CGU. If the asset does not generate cash inflows that are largely independent of those from other assets or groups of assets, the asset is tested as part of a CGU, 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. Determination of the Company's CGUs is subject to management's judgment.

FVLCS is the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The FVLCS is generally determined as the net present value of the estimated future cash flows expected to arise from a CGU, including any expansion prospects, and its eventual disposal, using assumptions that an independent market participant may take into account. These cash flows are discounted using a rate that would be applied by a market participant to arrive at a net present value of the CGU.

VIU is the net present value of the estimated future cash flows expected to arise from the continued use of the asset in its present form and its eventual disposal. VIU is determined by applying assumptions specific to the Company's continued use and can only take into account sanctioned future development costs. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices, operating costs and future capital expenditures, 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.

Given that the calculations for recoverable amounts require the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and in the case of oil and gas properties, expected production volumes, it is possible that the assumptions may change, which may impact the estimated life of the CGU and may require a material adjustment to the carrying value of goodwill and non-financial assets.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its estimated recoverable amount. Impairment losses recognized with respect to CGUs are allocated first to reduce the carrying amount of any goodwill allocated to the units and then to reduce the carrying amounts of the other assets in the CGU or group of CGUs on a pro rata basis. Impairment losses are recognized in depletion, depreciation, amortization and impairment in the consolidated statements of income.

Impairment losses recognized 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 CGU does not exceed the carrying amount that would have been determined, net of depletion, depreciation and amortization, if no impairment loss had been recognized.

j) Asset Retirement Obligations ("ARO")

A liability is recognized for future legal or constructive retirement obligations associated with the Company's assets. The Company has significant obligations to remove tangible assets and restore land after operations cease and the Company retires or relinquishes the asset. The retirement of Upstream and Downstream assets consists primarily of plugging and abandoning wells, abandoning surface and subsea plant and equipment and facilities and restoring land to a state required by regulation or contract. The amount recognized is the net present value of the estimated future expenditures determined in accordance with local conditions, current technology and current regulatory requirements. The obligation is calculated using the current estimated costs to retire the asset inflated to the estimated retirement date and then discounted using a credit-adjusted risk-free discount rate. The liability is recorded in the period in which an obligation arises with a corresponding increase to the carrying value of the related asset. The liability is progressively accreted over time as the effect of discounting unwinds, creating an expense recognized in finance expenses. The costs capitalized to the related assets are amortized in a manner consistent with the depletion, depreciation and amortization of the underlying assets. Actual retirement expenditures are charged against the accumulated liability as incurred.

Liabilities for ARO are adjusted every reporting period for changes in estimates. These adjustments are accounted for as a change in the corresponding capitalized cost, except where a reduction in the provision is greater than the undepreciated capitalized cost of the related assets, in which case the capitalized cost is reduced to nil and the remaining adjustment is recognized in net earnings. Changes to the amount of capitalized costs will result in an adjustment to future depletion, depreciation and amortization, and to finance expenses.

Estimating the ARO requires significant judgment as restoration technologies and costs are constantly changing, as are regulatory, political, environmental and safety considerations. Inherent in the calculation of the ARO are numerous assumptions including the ultimate settlement amounts, future third-party pricing, inflation factors, risk-free discount rates, credit risk, timing of settlement and changes in the legal, regulatory, environmental and political environments. Future revisions to these assumptions may result in material changes to the ARO liability. Adjustments to the estimated amounts and timing of future ARO cash flows are a regular occurrence in light of the significant judgments and estimates involved.

k) Legal and Other Contingent Matters

Provisions and liabilities for legal and other contingent matters are recognized in the period when the circumstance becomes probable that a future cash outflow resulting from past operations or events will occur and the amount of the cash outflow can be reasonably estimated. The timing of recognition and measurement of the provision requires the application of judgment to existing facts and circumstances, which can be subject to change, and the carrying amounts of provisions and liabilities are reviewed regularly and adjusted accordingly. The Company is required to both determine whether a loss is probable based on judgment and interpretation of laws and regulations, and determine that the loss can be reasonably estimated. When a loss is recognized, it is charged to net earnings. The Company continually monitors known and potential contingent matters and makes appropriate disclosure and provisions when warranted by the circumstances present.

l) Share Capital

Preferred shares are classified as equity since they are cancellable and redeemable only at the Company’s option and dividends are discretionary and payable only if declared by the Board of Directors. Incremental costs directly attributable to the issuance of shares and stock options are recognized as a deduction from equity, net of tax. Common share dividends are paid out in common shares, or in cash, and preferred share dividends are paid in cash. Both common and preferred share dividends are recognized as distributions within equity.

m) Financial Instruments

Financial instruments are any contracts that give rise to a financial asset of one entity and a financial liability or equity instrument of another entity. Financial instruments are initially recognized at fair value, and subsequently measured based on classification in one of the following categories: loans and receivables, held to maturity investments, other financial liabilities, fair value through profit or loss (“FVTPL”) or available-for-sale (“AFS”) financial assets.

Financial instruments classified as FVTPL or AFS are measured at fair value at each reporting date; any transaction costs associated with these types of instruments are expensed as incurred. Unrealized gains and losses on AFS financial assets are recognized in OCI (see policy note o) and transferred to net earnings when the asset is derecognized. Unrealized gains and losses on FVTPL financial instruments related to trading activities are recognized in marketing and other in the consolidated statements of income, and unrealized gains and losses on all other FVTPL financial instruments are recognized in other—net.

Financial instruments classified as loans or receivables, held to maturity investments and other financial liabilities are initially measured at fair value and subsequently carried at amortized cost using the effective interest rate method. Transaction costs that are directly attributable to the acquisition or issue of a financial instrument are measured at amortized cost and added to the fair value initially recognized.

Financial instruments subsequently revalued at fair value are further categorized using a three-level hierarchy that reflects the significance of the inputs used in determining fair value. Level 1 fair value is determined by reference to quoted prices in active markets for identical assets and liabilities. Level 2 fair value is based on inputs that are independently observable for similar assets or liabilities. Level 3 fair value is not based on independently observable market data. The disclosure of the fair value hierarchy excludes financial assets and liabilities where book value approximates fair value.

n) Derivative Instruments and Hedging Activities

Derivatives are financial instruments for which the fair value changes in response to market risks, require little or no initial investment and are settled at a future date. Derivative instruments are utilized by the Company to manage various market risks including volatility in commodity prices, foreign exchange rates and interest rate exposures. The Company's policy is not to utilize derivative instruments for speculative purposes. The Company may enter into swap and other derivative transactions to hedge or mitigate the Company's commercial risk, including derivatives that reduce risks that arise in the ordinary course of the Company's business. The Company may choose to apply hedge accounting to derivative instruments.

The fair values of derivatives are determined using valuation models that 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.

i) Derivative Instruments

All derivative instruments, other than those designated as effective hedging instruments or certain non-financial derivative contracts that meet the Company's own use requirements, are classified as held for trading and are recorded at fair value. Gains and losses on these instruments are recorded in the consolidated statements of income in the period they occur.

The Company may enter into commodity price contracts in order to offset fixed or floating prices with market rates to manage exposures to fluctuations in commodity prices. The estimation of the fair value of commodity derivatives incorporates forward prices and adjustments for quality or location. The related inventory is measured at fair value based on exit prices. Gains and losses from these derivative contracts, which are not designated as effective hedging instruments, are recognized in revenues or purchases of crude oil and products and are initially recorded at settlement date. Derivative instruments that have been designated as effective hedging instruments are further classified as either fair value or cash flow hedges (see "Hedging Activities").

ii) Embedded Derivatives

Derivatives embedded in a host contract are recorded separately when the economic characteristics and risks of the embedded derivative are not clearly and closely related to those of the host contract and the host contract is not measured at FVTPL. The definition of an embedded derivative is the same as freestanding derivatives. Embedded derivatives are measured at fair value with gains and losses recognized in net earnings.

iii) Hedging Activities

At the inception of a derivative transaction, if the Company elects to use hedge accounting, formal designation and documentation is required. The documentation must include: identification of the hedged item or transaction, the hedging instrument, the nature of the risk being hedged, the Company's risk management objective and strategy for undertaking the hedge and how the Company will assess the hedging instrument's effectiveness in offsetting the exposure to changes in the hedged item.

A hedge is assessed at inception and at the end of each reporting period to ensure that it is highly effective in offsetting changes in fair values or cash flows of the hedged item. For a fair value hedge, the gain or loss from remeasuring the hedging instrument at fair value is recognized immediately in net earnings with the offsetting gain or loss on the hedged item. When fair value hedge accounting is discontinued, the carrying amount of the hedging instrument is deferred and amortized to net earnings over the remaining maturity of the hedged item.

For a cash flow hedge, the effective portion of the gain or loss is recorded in OCI. Any hedge or portion of a hedge that is ineffective is immediately recognized in net earnings. Hedge accounting is discontinued on a prospective basis when the hedging relationship no longer qualifies for hedge accounting. Any gain or loss on the hedging instrument resulting from the discontinuation of a cash flow hedge is deferred in OCI until the forecasted transaction date. If the forecasted transaction date is no longer expected to occur, the gain or loss is recognized in net earnings in the period of discontinuation.

A net investment hedge of a foreign operation is accounted for similarly to a cash flow hedge. The Company may designate certain U.S. dollar denominated debt as a hedge of its net investment in foreign operations for which the U.S. dollar is the functional currency. The unrealized foreign exchange gains and losses arising from the translation of the debt are recorded in OCI, net of tax, and are limited to the translation gain or loss on the net investment.

o) Comprehensive Income

Comprehensive income consists of net earnings and OCI. OCI is comprised of the change in the fair value of the effective portion of the derivatives used as hedging items in a cash flow hedge or net investment hedge, the unrealized gains and losses on AFS financial assets, the exchange gains and losses arising from the translation of foreign operations with a functional currency that is not Canadian dollars and the actuarial gains and losses on defined benefit pension plans. Amounts included in OCI are shown net of tax. Other reserves is an equity category comprised of the cumulative amounts of OCI, relating to foreign currency translation and hedging.

p) 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.

An impairment loss with respect to a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the net present value of the estimated future cash flows discounted at the original effective interest rate. A revaluation with respect to an AFS financial asset is calculated by reference to its fair value and any amounts in OCI are transferred to net earnings.

Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net earnings. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized.

Given that the calculations for the net present value of estimated future cash flows related to derivative financial assets require the use of estimates and assumptions, including forecasts of commodity prices, marketing supply and demand, product margins and expected production volumes, it is possible that the assumptions may change, which may require a material adjustment to the carrying value of financial assets.

q) Pensions and Other Post-employment Benefits

In Canada, the Company provides a defined contribution pension plan and other post-retirement benefits to qualified employees. The Company also maintains a defined benefit pension plan for a small number of employees who did not choose to join the defined contribution pension plan in 1991. In the United States, the Company provides two defined contribution pension plans (401(k)) and one other post-retirement benefits plan. The Company also maintains a small defined benefit pension plan for the employees of the Superior Refinery.

The cost of the pension benefits earned by employees in the defined contribution pension plans is expensed as incurred. The cost of the benefits earned by employees in the defined benefit pension plans is determined using the projected unit credit funding method. Actuarial gains and losses are recognized in retained earnings as incurred.

The defined benefit asset or liability is comprised of the fair value of plan assets from which the obligations are to be settled and the present value of the defined benefit obligation. Plan assets are measured at fair value based on the closing bid price when there is a quoted price in an active market. Plan assets are assets that are held by a long-term employee benefit fund or qualifying insurance policies. Plan assets are not available to the Company's creditors. The value of any defined benefit asset is restricted to the sum of any past service costs and the present value of refunds from and reductions in future contributions to the plan. Defined benefit obligations are estimated by discounting expected future payments using the year-end market rate of interest for high-quality corporate debt instruments with cash flows that match the timing and amount of expected benefit payments.

Post-retirement medical benefits are also provided to qualifying retirees. In some cases the benefits are provided through medical care plans to which the Company, the employees, the retirees and covered family members contribute. In some plans there is no funding of the benefits before retirement. These plans are recognized on the same basis as described above for the defined benefit pension plan.

The determination of the cost of the defined benefit pension plan and the other post-retirement benefit plans reflects a number of assumptions that affect the expected future benefit payments. The valuation of these plans is prepared by an independent actuary engaged by the Company. These assumptions include, but are not limited to, the estimate of expected plan investment performance, salary escalation, retirement age, attrition, future health care costs and mortality. The fair value of the plan assets is used for the purposes of calculating the expected return on plan assets.

The assumptions for each country are reviewed each year and are adjusted where necessary to reflect changes in fund experience and actuarial recommendations. Mortality rates are based on the latest available standard mortality tables for the individual countries concerned. The rate of return on pension plan assets is based on a projection of real long-term bond yields and an equity risk premium, which are combined with local inflation assumptions and applied to the actual asset mix of each plan. The amount of the expected return on plan assets is calculated using the expected rate of return for the year and the fair value of assets at the beginning of the year. Future salary increases are based on expected future inflation rates for the individual countries.

r) Income Taxes

Current income tax is recognized in net earnings in the period unless it relates to items recognized directly to equity, including OCI, in which case the deferred income tax is also recorded in equity. Any interest and penalties on income taxes are recognized in interest expense and interest payable. Management periodically evaluates positions taken in the Company's tax returns with respect to situations in which applicable tax regulations are subject to interpretation and reassessment and establishes provisions where appropriate.

Deferred tax is measured using the liability method on temporary differences at the reporting date between the tax bases of assets and liabilities and their carrying amounts for financial reporting purposes.

Deferred tax assets and liabilities are recognized at expected tax rates in effect in the year when the asset is expected to be realized or the liability settled, based on tax rates and tax laws that have been enacted or substantively enacted at the reporting date. Deferred income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted with the adjustment being recognized in net earnings in the period that the change occurs unless it relates to items recognized directly to equity, including OCI, in which case the deferred income tax is also recorded in equity. Deferred tax assets and deferred tax liabilities are offset if a legally enforceable right exists to set off current tax assets against current income tax liabilities and the deferred taxes relate to the same taxable entity and the same taxation authority.

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 after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded by management.

s) Asset Exchange Transactions

Asset exchange transactions are measured at cost if the transaction lacks commercial substance or the fair value of neither the asset received nor the asset given up is reliably measurable. Otherwise, asset exchange transactions are measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. If the acquired item is not measured at fair value, its cost is measured at the carrying amount of the asset given up. Gains and losses are recorded in other—net in the consolidated statements of income in the period they occur.

t) Revenue Recognition

Revenue from the sale of goods is recognized when the significant risks and rewards of ownership have passed to the buyer and it can be reliably measured. Revenues associated with the sale of crude oil, natural gas, natural gas liquids, synthetic crude oil, purchased commodities and refined petroleum products are recognized when the title passes to the customer. Revenues associated with the sale of transportation, processing and natural gas storage services are recognized when the services are provided. Revenues from construction contracts are recognized using the percentage of completion method based upon costs incurred and may be recorded on a net or gross basis dependent on whether the Company is acting as an agent or principal, respectively.

Under take or pay contracts, the Company makes a long-term supply commitment in return for a commitment from the buyer to pay for minimum quantities, whether or not the customer takes delivery. If a buyer has a right to get a "make-up" delivery at a later date, revenue is deferred and recognized only when the product is delivered or the make-up product can no longer be taken. If no such option exists within the contractual terms, revenue is recognized when the take-or-pay penalty is triggered.

Revenue is measured at the fair value of the consideration received or receivable and represents amounts receivable for goods or services provided in the normal course of business, net of discounts, customs duties and sales taxes. Crude oil and natural gas sold below or above the Company's working interest share of production results in production underlifts or overlifts. Underlifts are recorded as a receivable at cost with a corresponding decrease to production and operating expense, while overlifts are recorded as a payable at fair value with a corresponding increase to production and operating expense.

Physical exchanges of inventory are reported on a net basis for swaps of similar items, as are sales and purchases made with a common counterparty as part of an arrangement similar to a physical exchange.

Finance income is recognized as the interest accrues using the effective interest rate, which is the rate that exactly discounts estimated future cash receipts through the expected life of the financial instrument to the net carrying amount of the financial asset.

u) Foreign 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 financial statements of Husky's subsidiaries are translated into Canadian dollars, which is the presentation and functional currency of the Company. The assets and liabilities of subsidiaries whose functional currencies are other than Canadian dollars are translated into Canadian dollars at the foreign exchange rate at the balance sheet date, while revenues and expenses of such subsidiaries are translated using average monthly foreign exchange rates, which approximate the foreign exchange rates on the dates of the transactions. Foreign exchange differences arising on translation are included in OCI.

The Company's transactions in foreign currencies are translated to the appropriate functional currency at the foreign exchange rate on the dates of the transactions. Monetary assets and liabilities denominated in foreign currencies are translated to the functional currency at the foreign exchange rate at the balance sheet date and differences arising on translation are recognized in net earnings. Non-monetary assets that are measured in terms of historical cost in a foreign currency are translated using the exchange rate at the dates of the transactions.

v) Share-based Payments

In accordance with the Company's stock option plan, stock options to acquire common shares may be granted to officers and certain other employees. The Company records compensation expense over the vesting period based on the fair value of options granted. Compensation expense is recorded in net earnings as part of selling, general and administrative expenses.

The Company's stock option plan is a tandem plan that provides the stock option holder with the right to exercise the stock option or surrender the option for a cash payment. A liability for the stock options is accrued over their vesting period and measured at fair value using the Black-Scholes option pricing model. The liability is revalued each reporting period until it is settled to reflect changes in the fair value of the options. The net change is recognized in net earnings. When stock options are surrendered for cash, the cash settlement paid reduces the outstanding liability. When stock options are exercised for common shares, consideration paid by the stock option holders and the previously recognized liability associated with the stock options are recorded as share capital.

The Company's Performance Share Unit Plan provides a time-vested award to certain officers and employees of the Company. Performance Share Units ("PSU") entitle participants to receive cash based on the Company's share price at the time of vesting. The amount of cash payment is contingent on the Company's total shareholder return relative to a peer group of companies and achieving a return on capital in use ("ROCIU") target. ROCIU equals net earnings plus after tax interest expense divided by the two-year average capital employed, less any capital invested in assets that are not in use. Net earnings is adjusted for the difference between actual realized and budgeted commodity prices and foreign exchange rates and other actual and budgeted exceptional items. A liability for expected cash payments is accrued over the vesting period of the PSUs and is revalued at each reporting date based on the market price of the Company's common shares and the expected vesting percentage. Upon vesting, a cash payment is made to the participants and the outstanding liability is reduced by the payment amount.

w) Earnings per Share

The number of basic common shares outstanding is the weighted average number of common shares outstanding for each period. Shares issued during the period are included in the weighted average number of shares from the date consideration is received. The calculation of basic earnings per common share is based on net earnings attributable to common shareholders divided by the weighted average number of common shares outstanding.

The number of diluted common shares outstanding is calculated using the treasury stock method, which assumes that any proceeds received from in-the-money stock options would be used to buy back common shares at the average market price for the period. The calculation of diluted earnings per share is based on net earnings attributable to common shareholders divided by the weighted average number of common shares outstanding adjusted for the effects of all potential dilutive common share issuances, which are comprised of common shares issuable upon exercise of stock options granted to employees. Stock options granted to employees provide the holder with the ability to settle in cash or equity. For the purposes of the diluted earnings per share calculation, the Company must adjust the numerator for the more dilutive effect of cash-settlement versus equity-settlement despite how the stock options are accounted for in net earnings. As a result, net earnings reported based on accounting of cash-settled stock options may be adjusted for the results of equity-settlements for the purposes of determining the numerator for the diluted earnings per share calculation.

x) Government Grants

Government grants are recognized when there is reasonable assurance that the grant will be received and all attached conditions will be complied with. If a grant is received but reasonable assurance and compliance with conditions is not achieved, the grant is recognized as a deferred liability until such conditions are fulfilled. When the grant relates to an expense item, it is recognized as income in the period in which the costs are incurred. Where the grant relates to an asset, it is recognized as a reduction to the net book value of the related asset and recognized in net earnings in equal amounts over the expected useful life of the related asset through lower depletion, depreciation and amortization.

y) Related Party Judgments and Estimates

The Company enters 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. See Note 25.

z) 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 other comprehensive income 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 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.

aa) 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. See Note 15.

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.

Note 4 Cash and Cash Equivalents

Cash and cash equivalents at December 31, 2017 included $280 million of cash (December 31, 2016 – $271 million) and $2,233 million of short-term investments with original maturities less than three months at the time of purchase (December 31, 2016 – $1,048 million).

Note 5 Accounts Receivable

Accounts Receivable

($ millions)	**December 31, 2017**	December 31, 2016
Trade receivables	**1,170**	1,019
Allowance for doubtful accounts	**(34)**	(32)
Derivatives due within one year	**17**	9
Other	**33**	40
End of year	**1,186**	1,036

Note 6 Inventories

Inventories

($ millions)	**December 31, 2017**	December 31, 2016
Crude oil, natural gas and sulphur	**539**	523
Refined petroleum products	**548**	433
Trading inventories measured at fair value less costs to sell	**237**	399
Materials, supplies and other	**189**	203
End of year	**1,513**	1,558

Impairment of inventory to net realizable value for the year ended December 31, 2017 was nil (December 31, 2016 – $9 million).

Trading inventories measured at fair value less costs to sell consist of natural gas inventories and crude oil inventories. The fair value measurement incorporates exit commodity prices and adjustments for quality and location. Refer to Note 24.

Note 7 Restricted Cash

In accordance with the provisions of the regulations of the People's Republic of China, the Company is required to deposit funds into separate accounts restricted to the funding of future asset retirement obligations in offshore China. As at December 31, 2017, the Company had deposited funds of $192 million (2016 – $156 million), of which $95 million (December 31, 2016—$84 million) relates to the Wenchang field and has been classified as current. The remaining balance of $97 million (December 31, 2016—$72 million) has been classified as non-current.

The Company's participation in the Wenchang field expired in November 2017, and the resolution on the decommissioning and disposal expenses was finalized in January 2018.

Note 8 Exploration and Evaluation Costs

Exploration and Evaluation Assets

($ millions)	**2017**	2016
Beginning of year	**1,066**	1,091
Additions	**224**	95
Disposals	**—**	(6)
Transfers to oil and gas properties (note 9)	**(377)**	(18)
Expensed exploration expenditures previously capitalized	**(6)**	(86)
Exchange adjustments	**(69)**	(10)
End of year	**838**	1,066

The following exploration and evaluation expenses for the years ended December 31, 2017 and 2016 relate to activities associated with the exploration for and evaluation of crude oil and natural gas resources and were recorded in the Upstream Exploration and Production business.

Exploration and Evaluation Expense Summary

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

Note 9 Property, Plant and Equipment

Property, Plant and Equipment

($ millions)	Oil and Gas Properties	Processing, Transportation and Storage	Upgrading	Refining	Retail and Other	Total
Cost						
December 31, 2015	50,388	1,465	2,313	8,136	2,688	64,990
Additions	818	55	51	712	61	1,697
Acquisitions	67	—	—	—	—	67
Transfers from exploration and evaluation *(note 8)*	18	—	—	—	—	18
Changes in asset retirement obligations *(note 16)*	231	—	3	11	9	254
Disposals and derecognition	(6,590)	(1,383)	—	—	(3)	(7,976)
Exchange adjustments	(131)	—	—	(214)	—	(345)
December 31, 2016	44,801	137	2,367	8,645	2,755	58,705
Additions[(1)]	**1,371**	**11**	**230**	**561**	**140**	**2,313**
Acquisitions	**29**	**—**	**—**	**577**	**—**	**606**
Transfers from exploration and evaluation *(note 8)*	**377**	**—**	**—**	**—**	**—**	**377**
Intersegment transfers	**48**	**(61)**	**—**	**—**	**13**	**—**
Changes in asset retirement obligations *(note 16)*	**150**	**—**	**2**	**13**	**23**	**188**
Disposals and derecognition	**(4,702)**	**—**	**—**	**(39)**	**—**	**(4,741)**
Exchange adjustments	**(259)**	**(1)**	**—**	**(566)**	**(1)**	**(827)**
December 31, 2017	**41,815**	**86**	**2,599**	**9,191**	**2,930**	**56,621**
Accumulated depletion, depreciation, amortization and impairment						
December 31, 2015	(31,300)	(574)	(1,260)	(2,676)	(1,546)	(37,356)
Depletion, depreciation, amortization and impairment	(1,806)	(23)	(103)	(380)	(150)	(2,462)
Disposals and derecognition	5,082	501	—	13	4	5,600
Exchange adjustments	38	—	—	68	—	106
December 31, 2016	(27,986)	(96)	(1,363)	(2,975)	(1,692)	(34,112)
Depletion, depreciation, amortization and impairment	**(2,238)**	**(2)**	**(99)**	**(406)**	**(137)**	**(2,882)**
Intersegment transfers	**(37)**	**50**	**—**	**—**	**(13)**	**—**
Disposals and derecognition	**4,124**	**—**	**—**	**16**	**—**	**4,140**
Exchange adjustments	**121**	**1**	**—**	**189**	**—**	**311**
December 31, 2017	**(26,016)**	**(47)**	**(1,462)**	**(3,176)**	**(1,842)**	**(32,543)**
Net book value						
December 31, 2016	16,815	41	1,004	5,670	1,063	24,593
December 31, 2017	**15,799**	**39**	**1,137**	**6,015**	**1,088**	**24,078**

(1) *Additions include assets under finance lease.*

Included in depletion, depreciation, amortization and impairment expense for the year ended December 31, 2017 is a pre-tax impairment expense of $173 million related to crude oil and natural gas assets, primarily in the Ram River and Foothills CGU's in the Upstream Exploration and Production segment (December 31, 2016 – a pre-tax net impairment reversal of $261 million). The impairment charges were a result of changes in the development plan and reinforced by market transactions. The associated assets were sold on December 20, 2017 for gross proceeds of $65 million, thereby representing the recoverable amounts of these assets. The recoverable amount was determined to be FVLCS based upon the observed market transaction (Level 1).

Costs of property, plant and equipment, including major development projects, not subject to depletion, depreciation and amortization as at December 31, 2017 were $2.8 billion (December 31, 2016 – $2.0 billion) including undeveloped land assets of $57 million as at December 31, 2017 (December 31, 2016 – $95 million).

The net book values of assets held under finance lease within property, plant and equipment are as follows:

Assets Under Finance Lease

($ millions)	Refining	Oil and Gas Properties	Total
December 31, 2016	24	255	279
December 31, 2017	**152**	**335**	**487**

Assets Dispositions

On May 25, 2016, the Company completed the sale of royalty interests representing approximately 1,700 boe/day of Western Canada production for gross proceeds of $165 million, resulting in a pre-tax gain of $163 million and an after-tax gain of $119 million.

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 Company also recognized an investment of $621 million for its 35 percent retained interest. This transaction resulted in a change of control and the recognition of a pre-tax gain of $1.44 billion and an after-tax gain of $1.32 billion. The assets and related liabilities were recorded in the Upstream Infrastructure and Marketing segment. The assets are held by a newly formed limited partnership, Husky Midstream Limited Partnership ("HMLP"), of which the Company owns 35 percent, Power Assets Holding Ltd. ("PAH") owns 48.75 percent and CK Infrastructure Holdings Ltd. ("CKI") owns 16.25 percent. Husky remains operator of the assets.

During 2016, the Company completed the sale of approximately 30,200 boe/day of legacy crude oil and gas assets in Western Canada for gross proceeds of $1.12 billion. The Company recognized a pre-tax gain of $35 million and an after-tax gain of $25 million.

During 2017, the Company completed the sale of select assets in Western Canada to third parties for gross proceeds of approximately $185 million, resulting in a pre-tax gain of $46 million and an after-tax gain of $36 million. The assets and related liabilities were recorded in the Upstream Exploration and Production segment.

Assets Acquisitions

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 acquisition has been accounted for as a business combination using the acquisition method. The purchase price allocation is based on management's best estimates of fair values of acquired assets and liabilities as at November 8, 2017:

Purchase Price Allocation

($ millions)	USD	CAD
Working capital	85	108
Property, plant and equipment	454	577
Asset retirement obligation	(7)	(9)
Other long-term liabilities	(5)	(6)
Net assets acquired	**527**	**670**

The fair values of accounts receivable and accounts payable approximate their carrying values due to their short-term nature. The fair value of inventory was determined using quoted prices. The fair values of property, plant and equipment were determined based on a cost and future cash flow approach. For the cost approach, key assumptions included the cost to construct the assets and the remaining useful life. For the cash flow approach, key assumptions were the discount rate and future commodity prices. The decommissioning provision was based on the fair value of estimated future reclamation costs. Key assumptions included discount rates, cost estimates and timeline to abandon and reclaim the refinery.

The acquisition of Superior Refinery contributed $163 million to gross revenues and a loss of $13 million to consolidated net earnings from the acquisition date to December 31, 2017.

Had the acquisition occurred on January 1, 2017, the Superior Refinery would have contributed $1.1 billion to gross revenues and $93 million to consolidated net earnings, which would have resulted in gross revenues of $19.9 billion and consolidated net earnings of $892 million for the year ended December 31, 2017.

Acquisition costs of $8 million have been charged to selling, general and administrative expenses in the consolidated statements of income for the year ended December 31, 2017.

Note 10 Goodwill

Goodwill

($ millions)	**December 31, 2017**	December 31, 2016
Beginning of year	**679**	700
Exchange adjustments	**(46)**	(21)
End of year	**633**	679

As at December 31, 2017, the Company's goodwill balance related entirely to the Lima Refinery. For impairment testing purposes, the recoverable amount of the Lima Refinery CGU was estimated using the higher of FVLCS and VIU methodology based on cash flows expected over a 50-year period and discounted using a pre-tax discount rate of 8 percent (2016 – 8 percent).

The value-in-use calculation for the Lima Refinery CGU is sensitive to changes in discount rate, forecasted crack spreads and growth rate. The discount rate is derived from the Company's post-tax weighted average cost of capital with appropriate adjustments made to reflect the risks specific to the refinery. Forecasted crack spreads are based on quoted near-month contracts for WTI and spot prices for gasoline and diesel, and are consistent with crack spreads used in the Company's long range plan.

Cash flow projections for the initial 10-year period are based on long range plan future cash flows and inflated by a 2 percent long-term growth rate for the remaining 40-year period. The inflation rate was based upon an average expected inflation rate for the U.S. of 2 percent (2016 – 2 percent). As at December 31, 2017, the recoverable amount exceeded the carrying amount and no impairment was identified.

The Company used the market capitalization and comparative market multiplier to corroborate discounted cash flow results.

Note 11 Joint Arrangements

Joint Operations

BP-Husky Refining LLC

The Company holds a 50 percent ownership interest in BP-Husky Refining LLC, which owns and operates the BP-Husky Toledo Refinery in Ohio. On March 31, 2008, the Company completed a transaction with BP whereby BP contributed the BP-Husky Toledo Refinery plus inventories and other related net assets and the Company contributed US$250 million in cash and a contribution payable of US $2.6 billion.

The Company's proportionate share of the contribution payable included in the consolidated balance sheets is as follows:

Contribution Payable

($ millions)	**December 31, 2017**	December 31, 2016
Beginning of year	**146**	348
Accretion *(note 21)*	**2**	6
Paid	**(142)**	(193)
Foreign exchange	**(6)**	(15)
End of year	**—**	146

The Company amended the terms of payment of the Company's contribution payable with BP-Husky Refining LLC in the first quarter of 2015. In accordance with the amendment, US$1 billion of the net contribution payable was paid on February 2, 2015. Subsequent to the payment, BP-Husky Refining LLC distributed US$1 billion to each of the joint arrangement partners, which resulted in the creation of a deferred tax asset and deferred tax recovery of $203 million. As a result of the prepayment, the accretion rate was reduced from 6 percent to 2.5 percent for the future term of the agreement and the remaining maturity date was extended to December 31, 2017. The remaining net contribution payable amount of approximately US$110 million (CDN $142 million) was repaid in 2017.

Summarized below is the Company's proportionate share of operating results and financial position in the BP-Husky Refining LLC joint operation that have been included in the consolidated statements of income and the consolidated balance sheets in U.S. Refining and Marketing in the Downstream segment:

Results of Operations

($ millions)	**2017**	2016
Revenues	**2,239**	1,521
Expenses	**(2,215)**	(1,570)
Proportionate share of net earnings (loss)	**24**	(49)

Balance Sheets

($ millions)	**December 31, 2017**	December 31, 2016
Current assets	**424**	395
Non-current assets	**2,195**	2,446
Current liabilities	**(324)**	(324)
Non-current liabilities	**(467)**	(535)
Proportionate share of net assets	**1,828**	1,982

Sunrise Oil Sands Partnership

The Company holds a 50 percent interest in the Sunrise Oil Sands Partnership, which is engaged in operating an oil sands project in Northern Alberta.

Summarized below is the Company's proportionate share of operating results and financial position in the Sunrise Oil Sands Partnership that have been included in the consolidated statements of income and the consolidated balance sheets in Exploration and Production in the Upstream segment:

Results of Operations

($ millions)	**2017**	2016
Revenues	**259**	106
Expenses	**(261)**	(220)
Financial items	**(28)**	(28)
Proportionate share of net loss	**(30)**	(142)

Balance Sheets

($ millions)	**December 31, 2017**	December 31, 2016
Current assets	**76**	57
Non-current assets	**2,756**	3,147
Current liabilities	**(129)**	(98)
Non-current liabilities	**(275)**	(274)
Proportionate share of net assets	**2,428**	2,832

Joint Venture

Husky-CNOOC Madura Ltd.

The Company currently holds 40 percent joint control in Husky-CNOOC Madura Ltd., which is engaged in the exploration for and production of oil and gas resources in Indonesia. Results of the joint venture are included in the consolidated statements of income in Exploration and Production in the Upstream segment.

Summarized below is the financial information for Husky-CNOOC Madura Ltd. accounted for using the equity method:

Results of Operations

($ millions, except share of equity investment)	**2017**	2016
Revenues	**97**	—
Expenses	**(80)**	(32)
Net earnings (loss)	**17**	(32)
Share of equity investment *(percent)*	**40%**	40%
Proportionate share of equity investment	**12**	(1)

Balance Sheets

($ millions, except share of equity investment)	**December 31, 2017**	December 31, 2016
Current assets[(1)]	**152**	67
Non-current assets	**1,993**	1,111
Current liabilities	**(1,021)**	(134)
Non-current liabilities	**(898)**	(836)
Net assets	**226**	208
Share of net assets *(percent)*	**40%**	40%
Carrying amount in balance sheet	**553**	488

(1) *Current assets include cash and cash equivalents of $26 million (2016 – $7 million).*

The Company's share of equity investment and carrying amount of share of net assets does not equal the 40 percent joint control of the expenses and net assets of Husky-CNOOC Madura Ltd. due to differences in the accounting policies of the joint venture and the Company and non-current liabilities of the joint venture which are not included in the Company's carrying amount of net assets due to equity accounting.

Husky Midstream Limited Partnership

On July 15, 2016, the Company completed the sale of its ownership interest in select midstream assets in the Lloydminster region of Alberta and Saskatchewan. The assets are held by a newly-formed limited partnership, HMLP, of which Husky owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent. Results of the joint venture are included in the consolidated statements of income in Infrastructure and Marketing in the Upstream segment.

Summarized below is the financial information for HMLP accounted for using the equity method:

Results of Operations

($ millions, except share of equity investment)	**2017**	**2016**
Revenues	**294**	138
Expenses	**(107)**	(97)
Net income	**187**	41
Share of equity investment (*percent*)	**35%**	35%
Proportionate share of equity investment	**49**	16

Balance Sheet

($ millions, except share of net assets)	**December 31, 2017**	December 31, 2016
Current assets[1]	**152**	55
Non-current assets	**2,617**	2,403
Current liabilities	**(75)**	(44)
Non-current liabilities	**(690)**	(590)
Net assets	**2,004**	1,824
Share of net assets *(percent)*	**35%**	35%
Carrying amount in balance sheet	**685**	640

(1) Current assets include cash and cash equivalents of $28 million (2016 – $23 million).

The Company's share of equity investment and carrying amount of share of net assets does not equal the 35 percent joint control of the net income and net assets of HMLP due to the potential fluctuation in the partnership profit structure.

Note 12 Other Assets

Other Assets

($ millions)	**December 31, 2017**	December 31, 2016
Long-term receivables	**144**	117
Leasehold incentives	**2**	13
Precious metals	**21**	23
Other	**18**	19
End of period	**185**	172

Note 13 Bank Operating Loans

At December 31, 2017, the Company had unsecured short-term borrowing lines of credit with banks totalling $850 million[1] (December 31, 2016 – $670 million) and letters of credit under these lines of credit totalling $422 million (December 31, 2016 – $378 million). As at December 31, 2017, bank operating loans were nil (December 31, 2016 – nil). Interest payable is based on Bankers' Acceptance, CAD Prime Rate, U.S. LIBOR, or U.S. Base Rates.

The Sunrise Oil Sands Partnership has an unsecured demand credit facility of $10 million (December 31, 2016 – $10 million) available for general purposes. The Company's proportionate share of the liability for any drawings under this credit facility is $5 million (December 31, 2016 – $5 million). As at December 31, 2017, there was no balance outstanding under this credit facility (December 31, 2016 – nil).

(1) Includes $75 million demand facility available specifically for letters of credit only.

Note 14 Accounts Payable and Accrued Liabilities

Accounts Payable and Accrued Liabilities

($ millions)	**December 31, 2017**	December 31, 2016
Trade payables	**950**	762
Accrued liabilities	**1,791**	1,275
Dividend payable *(note 19)*	**9**	9
Stock-based compensation	**30**	17
Derivatives due within one year	**115**	61
Other	**138**	102
End of year	**3,033**	2,226

Note 15 Debt and Credit Facilities

Short-term Debt

($ millions)	**December 31, 2017**	December 31, 2016
Commercial paper[(1)]	**200**	200

(1) *The commercial paper is supported by the Company's syndicated credit facilities and the Company is authorized to issue commercial paper up to a maximum of $1.0 billion having a term not to exceed 365 days. The weighted average interest rate as at December 31, 2017 was 1.40 percent per annum (December 31, 2016 – 0.93 percent).*

Long-term Debt

		Canadian $ Amount		U.S. $ Denominated	
($ millions)	Maturity	**December 31, 2017**	December 31, 2016	**December 31, 2017**	December 31, 2016
Long-term debt					
6.15% notes[(1)(3)]	2019	**376**	403	**300**	300
7.25% notes[(1)(4)]	2019	**939**	1,007	**750**	750
5.00% notes[(5)]	2020	**400**	400	**—**	—
3.95% notes[(1)(4)]	2022	**626**	671	**500**	500
4.00% notes[(1)(4)]	2024	**939**	1,007	**750**	750
3.55% notes[(5)]	2025	**750**	750	**—**	—
3.60% notes[(5)]	2027	**750**	—	**—**	—
6.80% notes[(1)(4)]	2037	**484**	519	**387**	387
Debt issue costs[(2)]		**(24)**	(23)	**—**	—
Unwound interest rate swaps *(note 24)*[(6)]		**—**	2	**—**	—
Long-term debt		**5,240**	4,736	**2,687**	2,687
Long-term debt due within one year 6.20% notes[(1)(4)]	2017	**—**	403	**—**	300
Long-term debt due within one year		**—**	403	**—**	300

(1) *All of the Company's U.S. dollar denominated debt is designated as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency. Refer to Note 24 for Foreign Currency Risk Management.*

(2) *Calculated using the effective interest rate method.*

(3) *The 6.15% notes represent unsecured securities under a trust indenture dated June 14, 2002.*

(4) *The 7.25%, the 3.95%, the 4.00%, the 6.80% and the 6.20% notes represent unsecured securities under a trust indenture dated September 11, 2007.*

(5) *The 5.00%, the 3.55% and the 3.60% notes represent unsecured securities under a trust indenture dated December 21, 2009.*

(6) *Unwound interest rate swaps as at December 31, 2017 was less than $1 million.*

During the year ended December 31, 2017, the Company had a net cumulative long-term debt issuance of $385 million (2016 – net cumulative long-term debt repayments of $768 million) towards the Company's long-term debt.

Credit Facilities

On November 30, 2017, the maturity date for one of the Company's $2.0 billion revolving syndicated credit facility, previously set to expire on June 19, 2018, was extended to June 19, 2022.

As at December 31, 2017 the covenant under the Company's syndicated credit facilities was a debt to capital covenant, 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. As at December 31, 2017, the Company had no borrowings under its $2.0 billion facility expiring March 9, 2020 (December 31, 2016 – no borrowings) and no borrowings under its $2.0 billion facility expiring June 19, 2022 (December 31, 2016 – no borrowings).

There continues to be no difference between the terms of these facilities, other than their maturity dates. Interest payable is based on Bankers' Acceptance, CAD Prime Rate, U.S. LIBOR, or U.S. Base Rates, depending on the borrowing option selected and credit ratings assigned by certain credit rating agencies to the Company's rated senior unsecured debt.

Notes

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. This was completed by way of a prospectus supplement dated March 7, 2017, to the Company's universal short form base shelf prospectus dated February 23, 2015 (the "2015 Canadian Shelf Prospectus"). 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. The 2017 Canadian Shelf Prospectus replaces the 2015 Canadian Shelf Prospectus, which expired on March 23, 2017.

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 its 2017 Canadian Shelf Prospectus and US$3.0 billion under its 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 Company's notes, credit facilities and short-term lines of credit rank equally in right of payment.

Reconciliation of Changes of Liabilities to Cash Flows from Financing Activities

	Liabilities			
($ millions)	Short-term debt	Long-term debt due within one year	Long-term debt	Other long-term liabilities
December 31, 2016	200	403	4,736	1,020
Changes from financing cash flows				
Long-term debt issuance	**—**	**—**	**750**	**—**
Long-term debt repayment	**—**	**(365)**	**—**	**—**
Debt issue costs	**—**	**—**	**(6)**	**—**
Other	**—**	**—**	**—**	**18**
Total change from financing cash flows	**—**	**(365)**	**744**	**18**
Other changes - liability-related				
Foreign exchange	**—**	**(38)**	**—**	**(28)**
Fair value changes	**—**	**—**	**—**	**3**
Addition of finance lease obligations	**—**	**—**	**—**	**269**
Payment of finance lease obligations	**—**	**—**	**—**	**(29)**
Deferred revenue	**—**	**—**	**—**	**(16)**
Amortization of debt issuance costs	**—**	**—**	**3**	**—**
Foreign exchange recognized in OCI	**—**	**—**	**(243)**	**—**
Total other changes - liability related	**—**	**(38)**	**(240)**	**199**
December 31, 2017	**200**	**—**	**5,240**	**1,237**

Note 16 Asset Retirement Obligations

At December 31, 2017, the estimated total undiscounted inflation-adjusted amount required to settle the Company's ARO was $9.7 billion (December 31, 2016 – $11.4 billion). These obligations will be settled based on the useful lives of the underlying assets, which currently extend an average of 42 years (December 31, 2016 – 41 years) into the future. This amount has been discounted using credit-adjusted risk-free rates of 2.9 percent to 4.8 percent (December 31, 2016 – 2.8 percent to 5.3 percent) and an inflation rate of 2 percent (December 31, 2016 – 2 percent). Obligations related to future environmental remediation and cleanup of oil and gas assets are included in the estimated ARO.

The change in the provision in 2017 is primarily due to the disposition of select legacy Western Canada crude oil and natural gas assets in 2017 and 2016.

While the provision is based on management's best estimates of future costs, discount rates and the economic lives of the assets, there is uncertainty regarding the amount and timing of incurring these costs.

A reconciliation of the carrying amount of asset retirement obligations at December 31, 2017 and 2016 is set out below:

Asset Retirement Obligations

($ millions)	**2017**	2016
Beginning of year	**2,791**	2,984
Additions	**47**	16
Liabilities settled	**(136)**	(87)
Liabilities disposed	**(420)**	(452)
Change in discount rate	**143**	205
Change in estimates	**(2)**	25
Exchange adjustment	**(9)**	(26)
Accretion *(note 21)*	**112**	126
End of year	**2,526**	2,791
Expected to be incurred within 1 year	**274**	218
Expected to be incurred beyond 1 year	**2,252**	2,573

The Company had deposited funds of $192 million (2016 – $156 million) into the restricted cash account, of which $95 million relates to the Wenchang field and have been classified as current and the remaining balance of $97 million have been classified as non-current. The Company's participation in the Wenchang field expired in November 2017, and resolution on the decommissioning and disposal expenses was finalized in January 2018.

Note 17 Other Long-term Liabilities

Other Long-term Liabilities

($ millions)	**December 31, 2017**	December 31, 2016
Employee future benefits *(note 22)*	**248**	208
Finance lease obligations	**498**	288
Stock-based compensation	**32**	14
Deferred revenue	**284**	321
Leasehold incentives	**101**	104
Other	**74**	85
End of year	**1,237**	1,020

Finance lease obligations

The Company, on behalf of the Sunrise Oil Sands Partnership, entered into an arrangement for the construction and use of pipeline and storage facilities in its oil sands operations for a minimum period of 20 years with options to renew.

During the year ended December 31, 2017, the Company entered into an arrangement to lease a supply vessel to support the West White Rose Project and other Atlantic operations for a minimum period of 10 years with options to renew. The Company also entered into a five year refining feedstock transportation arrangement and an 18 year hydrogen supply arrangement. The substance of these arrangements have been determined to be finance lease obligations.

The future minimum lease payments under existing finance leases are payable as follows:

	Within 1 year		After 1 year but no more than 5 years		More than 5 years		Total	
($ millions)	**2017**	2016	**2017**	2016	**2017**	2016	**2017**	2016
Future minimum lease payments	**69**	35	**258**	140	**993**	764	**1,320**	939
Interest	**48**	30	**174**	112	**594**	505	**816**	647
Present value of minimum lease payments	**66**	33	**194**	102	**244**	153	**504**	288

Note 18 Income Taxes

The major components of income tax expense for the years ended December 31, 2017 and 2016 were as follows:

Income Tax Expense (Recovery)

($ millions)	**2017**	2016
Current income tax		
Current income tax charge	**28**	90
Adjustments to current income tax estimates	**(31)**	(91)
	(3)	(1)
Deferred income tax		
Relating to origination and reversal of temporary differences	**83**	(121)
Adjustments to deferred income tax estimates	**(442)**	150
	(359)	29

Deferred Tax Items in OCI

($ millions)	**2017**	2016
Deferred tax items expensed (recovered) directly in OCI		
Derivatives designated as cash flow hedges	**—**	(1)
Remeasurement of pension plans	**(4)**	(6)
Exchange differences on translation of foreign operations	**(82)**	(40)
Hedge of net investment	**38**	17
	(48)	(30)

The provision for income taxes in the consolidated statements of income reflects an effective tax rate which differs from the expected statutory tax rate. Differences for the years ended December 31, 2017 and 2016 were accounted for as follows:

Reconciliation of Effective Tax Rate

($ millions, except tax rate)	**2017**	2016
Earnings before income taxes		
Canada	**(440)**	615
United States	**301**	5
Other foreign jurisdictions	**563**	330
	424	950
Statutory Canadian income tax rate *(percent)*	**27.1%**	27.2%
Expected income tax	**115**	258
Effect on income tax resulting from:		
Foreign jurisdictions	**20**	(3)
Non-taxable items	**(1)**	(272)
Adjustments with respect to previous year	**(473)**	59
Revaluation of foreign tax pools	**(8)**	(11)
Other – net	**(15)**	(3)
Income tax expense (recovery)	**(362)**	28

The statutory tax rate is 27.1 percent in 2017 (2016 – 27.2 percent). The 2017 to 2016 tax rates were similar due to no significant changes to tax rates.

Effective January 1, 2018, the U.S. Federal corporate tax rate will be reduced from 35 percent to 21 percent. Included in income tax expense for the year ended December 31, 2017 is a $436 million deferred income tax recovery related to the revaluation of the U.S. deferred tax liabilities.

The following reconciles the movements in the deferred income tax liabilities and assets:

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2017	Recognized in Earnings	Recognized in OCI	Other	**December 31, 2017**
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(3,998)	**187**	**104**	**(20)**	**(3,727)**
Foreign exchange gains taxable on realization	(224)	**85**	**(38)**	**—**	**(177)**
Debt issue costs	(2)	**(1)**	**—**	**—**	**(3)**
Other temporary differences	(21)	**(69)**	**—**	**—**	**(90)**
Deferred tax assets					
Pension plans	32	**4**	**4**	**—**	**40**
Asset retirement obligations	693	**(8)**	**(6)**	**—**	**679**
Loss carry-forwards	389	**150**	**(16)**	**—**	**523**
Financial assets at fair value	20	**11**	**—**	**—**	**31**
	(3,111)	**359**	**48**	**(20)**	**(2,724)**

Deferred Tax Liabilities and Assets

($ millions)	January 1, 2016	Recognized in Earnings	Recognized in OCI	Other	December 31, 2016
Deferred tax liabilities					
Exploration and evaluation assets and property, plant and equipment	(4,233)	187	48	—	(3,998)
Foreign exchange gains taxable on realization	(42)	(166)	(16)	—	(224)
Debt issue costs	(1)	(1)	—	—	(2)
Other temporary differences	141	(162)	—	—	(21)
Deferred tax assets					
Pension plans	43	(17)	6	—	32
Asset retirement obligations	892	(196)	(3)	—	693
Loss carry-forwards	75	319	(5)	—	389
Financial assets at fair value	13	7	—	—	20
	(3,112)	(29)	30	—	(3,111)

The Company has temporary differences associated with its investments in its foreign subsidiaries, branches, and interests in joint ventures. At December 31, 2017, the Company has nil deferred tax liabilities in respect to these investments (December 31, 2016 –nil).

At December 31, 2017, the Company had $2,031 million (December 31, 2016 – $1,257 million) of tax losses that will expire between 2030 and 2037. The Company has recorded deferred tax assets in respect of these losses, as there are sufficient taxable temporary differences in the various jurisdictions to utilize these losses.

Note 19 Share Capital

Common Shares

The Company is authorized to issue an unlimited number of no par value common shares.

Common Shares	Number of Shares	Amount ($ millions)
December 31, 2015	984,328,915	7,000
Stock dividends	21,122,939	296
December 31, 2016	1,005,451,854	7,296
Share cancellation	**(331,842)**	**(3)**
December 31, 2017	**1,005,120,012**	**7,293**

Quarterly dividends may be declared in an amount expressed in dollars per common share or could be paid by way of issuance of a fraction of a common share per outstanding common share determined by dividing the dollar amount of the dividend by the volume-weighted average trading price of the common shares on the principal stock exchange on which the common shares are traded. The volume-weighted average trading price of the common shares is calculated by dividing the total value by the total volume of common shares traded over the five trading day period immediately prior to the payment date of the dividend on the common shares.

The quarterly common share dividend was suspended by the Board of Directors in respect of the fourth quarter of 2015. At December 31, 2017, the Company had no common share dividends payable (December 31, 2016 - nil).

On February 28, 2018, the Board of Directors have reinstated the quarterly common share dividend and declared cash dividends of $0.075 per common share, for the fourth quarter of 2017. The dividends are payable on April 2, 2018 to shareholders of record at the close of business on March 20, 2018.

Preferred Shares

The Company is authorized to issue an unlimited number of no par value preferred shares.

Cumulative Redeemable Preferred Shares	Number of Shares	Amount *($ millions)*
December 31, 2015	36,000,000	874
Series 1 shares converted to Series 2 shares	(1,564,068)	(38)
Series 2 shares converted from Series 1 shares	1,564,068	38
December 31, 2016	36,000,000	874
December 31, 2017	**36,000,000**	**874**

Cumulative Redeemable Preferred Shares Dividends

	2017		2016	
($ millions)	Declared	Paid	Declared	Paid
Series 1 Preferred Shares	**6**	**6**	9	7
Series 2 Preferred Shares[(1)]	**1**	**1**	—	—
Series 3 Preferred Shares	**11**	**11**	11	8
Series 5 Preferred Shares	**9**	**9**	9	7
Series 7 Preferred Shares	**7**	**7**	7	5
	34	**34**	36	27

(1) *Series 2 Preferred Share dividends declared and paid in the year ended December 31, 2016 was less than $1 million.*

At December 31, 2017 there were $9 million of Preferred Share dividends payable (December 31, 2016 - $9 million).

Holders of the Cumulative Redeemable Preferred Shares, Series 1 (the ”Series 1 Preferred Shares”) are entitled to receive a cumulative quarterly fixed dividend yielding 2.40 percent annually for a five year period ending March 31, 2021, as and when declared by the Company’s Board of Directors. Thereafter, the dividend rate will be reset every five years at a rate equal to the five-year Government of Canada bond yield plus 1.73 percent. Holders of Series 1 Preferred Shares have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 2 (the “Series 2 Preferred Shares”), subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter.

Holders of the Series 2 Preferred Shares are entitled to receive a cumulative quarterly floating rate dividend that is reset every quarter for a five year period ending March 31, 2021, as and when declared by the Company’s Board of Directors. The dividend rate applicable to the Series 2 Preferred Shares, for the three month period commencing September 30, 2017 but excluding December 31, 2017, was 2.472 percent based on the sum of the Government of Canada 90 day Treasury bill rate on August 31, 2017 plus 1.73 percent. Holders of Series 2 Preferred Shares have the right, at their option, to convert their shares into Series 1 Preferred Shares, subject to certain conditions, on March 31, 2021 and on March 31 every fiveyears thereafter.

Holders of the Cumulative Redeemable Preferred Shares, Series 3 (the ”Series 3 Preferred Shares”) are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending December 31, 2019 as and when declared by the Company’s Board of Directors. Thereafter, the dividend rate will be reset every five years at the rate equal to the five-year Government of Canada bond yield plus 3.13 percent. Holders of Series 3 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 4 (the ”Series 4 Preferred Shares”), subject to certain conditions, on December 31, 2019 and on December 31 every five years thereafter. Holders of the Series 4 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.13 percent.

Holders of the Cumulative Redeemable Preferred Shares, Series 5 (the ”Series 5 Preferred Shares”) are entitled to receive a cumulative quarterly fixed dividend yielding 4.50 percent annually for the initial period ending March 31, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every 5 years at the rate equal to the five-year Government of Canada bond yield plus 3.57 percent. Holders of Series 5 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 6 (the ”Series 6 Preferred Shares”), subject to certain conditions, on March 31, 2020 and on March 31 every five years thereafter. Holders of the Series 6 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.57 percent.

Holders of the Cumulative Redeemable Preferred Shares, Series 7 (the "Series 7 Preferred Shares") are entitled to receive a cumulative fixed dividend yielding 4.60 percent annually for the initial period ending June 30, 2020 as declared by the Board of Directors. Thereafter, the dividend rate will be reset every 5 years at the rate equal to the five-year Government of Canada bond yield plus 3.52 percent. Holders of the Series 7 Preferred Shares will have the right, at their option, to convert their shares into Cumulative Redeemable Preferred Shares, Series 8 (the "Series 8 Preferred Shares"), subject to certain conditions, on June 30, 2020 and on June 30 every 5 years thereafter. Holders of the Series 8 Preferred Shares will be entitled to receive cumulative quarterly floating dividends at a rate equal to the 90-day Government of Canada Treasury Bill yield plus 3.52 percent.

Stock Option Plan

Pursuant to the Incentive Stock Option Plan (the "Option Plan"), the Company may grant from time to time to officers and employees of the Company options to purchase common shares of the Company. The term of each option is five years, and vests one-third on each of the first three anniversary dates from the grant date. The Option Plan provides the option holder with the right to exercise the option to acquire one common share at the exercise price or surrender the option for a cash payment. The exercise price of the option is equal to the weighted average trading price of the Company's common shares during the five trading days prior to the grant date. When the stock option is surrendered to the Company, the cash payment is equal to the excess of the aggregate fair market value of the common shares able to be purchased pursuant to the vested and exercisable portion of such stock options on the date of surrender over the aggregate exercise price for those common shares pursuant to those stock options. The fair market value of common shares is calculated as the closing price of the common shares on the date on which board lots of common shares have traded immediately preceding the date a holder of the stock options provides notice to the Company that he or she wishes to surrender his or her stock options to the Company in lieu of exercise.

Included in accounts payable and accrued liabilities and other long-term liabilities in the consolidated balance sheets at December 31, 2017 was $21 million (December 31, 2016 – $8 million) representing the estimated fair value of options outstanding. The total expense recognized in selling, general and administrative expenses in the consolidated statements of income for the Option Plan for the year ended December 31, 2017 was $13 million (2016 – $7 million). At December 31, 2017, stock options exercisable for cash had an intrinsic value of $12 million (December 31, 2016 – $1 million).

The following options to purchase common shares have been awarded to officers and certain other employees:

Outstanding and Exercisable Options

	2017		2016	
	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
Outstanding, beginning of year	**25,459**	**26.26**	27,621	28.79
Granted[(1)]	**5,544**	**16.13**	5,381	15.67
Expired or forfeited	**(8,358)**	**25.62**	(7,543)	27.94
Outstanding, end of year	**22,645**	**23.96**	25,459	26.26
Exercisable, end of year	**12,946**	**28.91**	15,662	29.03

(1) *Options granted during the year ended December 31, 2017 were attributed a fair value of $2.01 per option (2016 – $2.26) at grant date.*

Outstanding and Exercisable Options

	Outstanding Options			Exercisable Options	
Range of Exercise Price	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*	Weighted Average Contractual Life *(years)*	Number of Options *(thousands)*	Weighted Average Exercise Prices *($)*
$ 14.20 – $ 29.99	14,281	18.89	3.3	4,582	22.18
$ 30.00 – $ 36.20	8,364	32.60	0.72	8,364	32.60
December 31, 2017	**22,645**	**23.96**	**2.35**	**12,946**	**28.91**

The fair value of the share options is estimated at each reporting date using the Black-Scholes option pricing model, taking into account the terms and conditions upon which the share options are granted and for the performance options, the current likelihood of achieving the specified target. The following table lists the assumptions used in the Black-Scholes option pricing model for the share options and performance options:

Black-Scholes Assumptions	**December 31, 2017**	December 31, 2016
	Tandem Options	Tandem Options
Dividend per option	**0.72**	0.96
Range of expected volatilities used *(percent)*	**16.7 - 32.9**	24.9 - 39.6
Range of risk-free interest rates used *(percent)*	**0.9 - 1.9**	0.4 - 1.1
Expected life of share options from vesting date *(years)*	**1.95**	1.91
Expected forfeiture rate *(percent)*	**9.0%**	9.3%
Weighted average exercise price	**25.46**	27.72
Weighted average fair value	**1.15**	0.37

The expected life of the share options is based on historical data and current expectations and is not necessarily indicative of exercise patterns that may occur.The expected volatility reflects the assumption that the historical volatility over a period similar to the expected life of the options is indicative of future trends, which may also not necessarily be the actual outcome.

Performance Share Units

In February 2010, the Compensation Committee of the Board of Directors of the Company established the Performance Share Unit Plan for executive officers and certain employees of the Company. The term of each PSU is three years, and the PSU vests on the second and third anniversary dates of the grant date in percentages determined by the Compensation Committee based on the Company's total shareholder return relative to a peer group of companies and achieving a ROCIU target set by the Company. ROCIU equals net earnings plus after tax interest expense divided by the two-year average capital employed, less any capital invested in assets that are not in use. Net earnings is adjusted for the difference between actual realized and budgeted commodity prices and foreign exchange rates and other actual and budgeted exceptional items. Upon vesting, PSU holders receive a cash payment equal to the number of vested PSUs multiplied by the weighted average trading price of the Company's common shares for the five preceding trading days. As at December 31, 2017, the carrying amount of the liability relating to PSUs was $41 million (December 31, 2016 – $24 million). The total expense recognized in selling, general and administrative expenses in the consolidated statements of income for the PSUs for the year ended December 31, 2017 was $32 million (2016 – $26 million). The Company paid out $15 million (2016 – $18 million) for performance share units which vested in the year. The weighted average contractual life of the PSUs at December 31, 2017 was two years (December 31, 2016 – one and a half years).

The number of PSUs outstanding was as follows:

Performance Share Units	**2017**	2016
Beginning of year	**4,863,690**	5,122,626
Granted	**5,667,970**	2,250,110
Exercised	**(966,932)**	(1,167,256)
Forfeited	**(1,202,810)**	(1,341,790)
Outstanding, end of year	**8,361,918**	4,863,690
Vested, end of year	**2,262,954**	1,490,243

Earnings per Share

Earnings per Share

($ millions)	**2017**	2016
Net earnings	**786**	922
Effect of dividends declared on preferred shares in the year	**(34)**	(36)
Net earnings – basic	**752**	886
Dilutive effect of accounting for stock options as cash-settled[(1)]	**4**	(3)
Net earnings – diluted	**756**	883

(millions)		
Weighted average common shares outstanding – basic and diluted	**1,005.3**	1,004.9
Earnings per share – basic *($/share)*	**0.75**	0.88
Earnings per share – diluted *($/share)*	**0.75**	0.88

(1) *Stock-based compensation expense was $13 million based on cash-settlement for the year ended December 31, 2017 (2016 – $7 million). Stock-based compensation expense would have been $9 million based on equity-settlement for the year ended December 31, 2017 (2016 – $10 million). For the year ended December 31, 2017, cash-settlement of stock options was used to calculate diluted earnings per share as it was considered more dilutive than equity-settlement.*

For the year ended December 31, 2017, 23 million tandem options (2016 – 25 million) were excluded from the calculation of diluted earnings per share as these options were anti-dilutive.

Note 20 Production, Operating and Transportation and Selling, General and Administrative Expenses

The following table summarizes production, operating and transportation expenses in the consolidated statements of income for the years ended December 31, 2017 and 2016:

Production, Operating and Transportation Expenses

($ millions)	**2017**	2016
Services and support costs	**930**	983
Salaries and benefits	**664**	631
Materials, equipment rentals and leases	**248**	259
Energy and utility	**453**	413
Licensing fees	**200**	246
Transportation	**26**	30
Other	**158**	162
Total production, operating and transportation expenses	**2,679**	2,724

The following table summarizes selling, general and administrative expenses in the consolidated statements of income for the years ended December 31, 2017 and 2016:

Selling, General and Administrative Expenses

($ millions)	**2017**	**2016**
Employee costs[(1)]	**395**	319
Stock-based compensation expense[(2)]	**45**	33
Contract services	**100**	85
Equipment rentals and leases	**37**	36
Maintenance and other	**73**	71
Total selling, general and administrative expenses	**650**	544

(1) *Employee costs are comprised of salary and benefits earned during the year, plus cash bonuses awarded during the year. Annual bonus awards settled in shares are included in stock-based compensation expense.*

(2) *Stock-based compensation expense represents the cost to the Company for participation in share-based payment plans.*

Note 21 Financial Items

Financial Items

($ millions)	**2017**	**2016**
Foreign exchange		
Non-cash working capital gains (losses)	**(3)**	4
Other foreign exchange gains (losses)	**(3)**	9
Net foreign exchange gains *(losses)*	**(6)**	13
Finance income	**37**	17
Finance expenses		
Long-term debt	**(342)**	(330)
Contribution payable *(note 11)*	**(2)**	(6)
Other	**(4)**	(17)
	(348)	(353)
Interest capitalized[(1)]	**68**	78
	(280)	(275)
Accretion of asset retirement obligations *(note 16)*	**(112)**	(126)
Finance expenses	**(392)**	(401)
Total Financial Items	**(361)**	(371)

(1) *Interest capitalized on project costs is calculated using the Company's annualized effective interest rate of 5 percent (2016 – 5 percent).*

Note 22 Pensions and Other Post-employment Benefits

The Company currently provides defined contribution pension plans for all qualified employees and two other post-employment benefit plans to its retirees. The other post-employment benefit plans provide certain retired employees with health care and dental benefits. The Company also maintains two defined benefit pension plans, which are closed to new entrants. The defined benefit pension plans provide pension benefits to certain employees based on years of service and final average earnings. The amount and timing of funding of these plans is subject to the funding policy as approved by the Board of Directors.

The measurement date of all plan assets and the accrued benefit obligations was December 31, 2017. The Company is required to file an actuarial valuation of its defined benefit pension with the provincial or state regulator at least every three years. The most recent actuarial valuation was December 31, 2016 for the Canadian defined benefit plan. The most recent actuarial valuation was December 31, 2014 for the Canadian Other Post-employment benefit plan. The most recent actuarial valuation of the U.S. Other Post-employment benefit plan was December 31, 2015.

Defined Contribution Pension Plan

During the year ended December 31, 2017, the Company recognized a $46 million expense (2016 – $46 million) for the defined contribution plan and the two U.S. 401(k) plans in net earnings.

Defined Benefit Pension Plan ("DB Pension Plan") and Other Post-employment Benefit Plans ("OPEB Plans")

Defined Benefit Obligation

	DB Pension Plan		OPEB Plans	
($ millions)	**2017**	2016	**2017**	2016
Beginning of year	**178**	177	**213**	180
Current service cost	**1**	1	**15**	13
Interest cost	**4**	6	**8**	7
Benefits paid	**(9)**	(11)	**(4)**	(3)
Settlements	**(140)**	—	**—**	—
Increase due to business combinations[(1)]	**34**	—	**—**	—
Remeasurements				
Actuarial (gain) loss – experience	**3**	(1)	**—**	(1)
Actuarial loss – financial assumptions	**5**	6	**12**	17
End of year	**76**	178	**244**	213

(1) *The Superior Refinery DB pension plan was transferred from Calumet GP.LLC to Husky Energy Inc. effective November 2017. Please refer to Note 9 for business combination.*

Fair Value of Plan Assets

	DB Pension Plan		OPEB Plans	
($ millions)	**2017**	2016	**2017**	2016
Beginning of year	**183**	181	**—**	—
Contributions by employer	**6**	2	**—**	—
Benefits paid	**(9)**	(11)	**—**	—
Interest income	**4**	6	**—**	—
Return on plan assets greater than discount rate	**4**	5	**—**	—
Settlements	**(148)**	—	**—**	—
Increase due to business combinations[(1)]	**27**	—	**—**	—
End of year	**67**	183	**—**	—

(1) *The Superior Refinery DB pension plan was transferred from Calumet GP.LLC to Husky Energy Inc. effective November 2017. Please refer to Note 9 for business combination.*

Funded status

	DB Pension Plan		OPEB Plans	
($ millions)	**2017**	2016	**2017**	2016
Net asset (liability)	**(9)**	5	**(244)**	(213)

The Company has accrued the total net liability for the DB Pension Plan and the OPEB Plans in the consolidated balance sheets in other long-term liabilities.

On July 27, 2017, the Company completed a series of transactions related to the Canadian DB Pension Plan. The most recent actuarial valuation at the transaction date was at December 31, 2016. Defined benefit assets and accrued obligations were remeasured immediately prior to the transactions. DB Pension Plan assets of $148 million, including a one-time cash contribution by the Company of $5 million, were used to settle $140 million of the defined benefit obligation related to the inactive plan members. This resulted in the Company recognizing a $8 million loss on settlement in Other – net expense.

As part of a risk management strategy the Company also purchased a $48 million annuity to offset the related $42 million defined benefit obligation for the active plan members. This resulted in a $3 million actuarial loss (net of tax of $1 million) on plan assets recorded in other comprehensive income.

The Company will continue to accrue service costs for the active plan members and the contribution to the plan for the next annual reporting period.

In November 2017, the Company also acquired a small defined benefit pension plan for the employees of the Superior Refinery which is closed to new entrants.

The composition of the DB Pension Plan assets at December 31, 2017 and 2016 was as follows:

DB Pension Plan Assets

(percent)	Target allocation range	**2017**	2016
Money market type funds	—	**0.2**	0.6
Equity securities	—	**—**	43.8
Debt securities	100	**99.8**	55.6

The following table summarizes amounts recognized in net earnings and OCI for the DB Pension Plan and the OPEB Plans for the years ended December 31, 2017 and 2016:

	DB Pension Plan		OPEB Plans	
($ millions)	**2017**	2016	**2017**	2016
Amounts recognized in net earnings				
Current service cost	**1**	1	**15**	13
Past service cost	**1**	—	**—**	—
Net Interest cost	**—**	—	**8**	7
Settlement loss	**8**	—	**—**	—
Benefit cost	**10**	1	**23**	20
Remeasurements				
Actuarial (gain) loss due to liability experience	**3**	(1)	**—**	(1)
Actuarial loss due to liability assumption changes	**5**	6	**12**	17
Gain on plan assets	**(4)**	(5)	**—**	—
Remeasurement effects recognized in OCI	**4**	—	**12**	16

The following long-term assumptions were used to estimate the value of the defined benefit obligations, the plan assets and the OPEB Plans:

Assumptions

	DB Pension Plan		OPEB Plans	
(percent)	**2017**	2016	**2017**	2016
Discount rate for benefit expense and obligation	**3.4 - 3.5**	3.5 - 3.8	**3.4 - 3.9**	3.7 - 4.1
Rate of compensation expense	**3.5**	3.5	**N/A**	N/A

The average health care cost trend rate used for the benefit expense for the Canadian OPEB Plan was 7.0 percent for 2017, grading 0.5 percent per year for 4 years to 5.0 percent in 2021 and thereafter. The average health care cost trend rate used for the obligation related to the Canadian OPEB Plan was 6.5 percent for 2017, grading 0.4 percent per year for 4 years to 5.0 percent in 2021 and thereafter.

The average health care cost trend rate used for the benefit expense for the U.S. OPEB Plan was 6.5 percent for 2017, grading 0.30 percent per year for 5 years to 5.0 percent per year in 2022 and thereafter.The average health care cost trend rate used for the obligation related to the U.S. OPEB Plan was 6.0 percent for 2017, grading 0.20 percent per year for 5 years to 5.0 percent in 2022 and thereafter.

The sensitivity of the defined benefit and OPEB obligation to changes in relevant actuarial assumption is shown below:

Sensitivity Analysis

	DB Pension Plan		OPEB Plans	
($ millions)	1% increase	1% decrease	1% increase	1% decrease
Discount rate	(9)	11	(41)	47
Health care cost trend rate	N/A	N/A	47	(36)

Note 23 Cash Flows – Change in Non-cash Working Capital

Non-cash Working Capital

($ millions)	2017	2016
Decrease (increase) in non-cash working capital		
Accounts receivable	**(329)**	(332)
Inventories	**(264)**	(334)
Prepaid expenses	**(38)**	131
Accounts payable and accrued liabilities	**1,201**	(33)
Change in non-cash working capital	**570**	(568)
Relating to:		
Operating activities	**398**	(227)
Financing activities	**—**	(68)
Investing activities	**172**	(273)

Note 24 Financial Instruments and Risk Management

Financial Instruments

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.

The following table summarizes the Company's financial instruments that are carried at fair value in the consolidated balance sheets:

Financial Instruments at Fair Value

($ millions)	December 31, 2017	December 31, 2016
Commodity contracts - fair value through profit or loss ("FVTPL")		
Natural gas[(1)]	**(13)**	5
Crude oil[(2)]	**(57)**	(30)
Foreign currency contracts - FVTPL		
Foreign currency forwards	**1**	—
Other assets – FVTPL	**1**	1
Hedge of net investment[(3)(4)]	**(584)**	(827)
End of year	**(652)**	(851)

(1) *Natural gas contracts includes a $3 million decrease at December 31, 2017 (December 31, 2016 – $11 million increase) to the fair value of held-for-trading inventory, recognized in the consolidated balance sheets, related to third party physical purchase and sale contracts for natural gas held in storage. Total fair value of the related natural gas storage inventory was $5 million at December 31, 2017 (December 31, 2016 – $45 million).*

(2) *Crude oil contracts includes an $5 million increase at December 31, 2017 (December 31, 2016 – $17 million increase) to the fair value of held-for-trading inventory, recognized in the consolidated balance sheets, related to third party crude oil physical purchase and sale contracts. Total fair value of the related crude oil inventory was $232 million at December 31, 2017 (December 31, 2016 – $354 million).*

(3) *Hedging instruments are presented net of tax.*

(4) *Represents the translation of the Company's U.S. dollar denominated long-term debt designated as a hedge of the Company's net investment in selected foreign operations with a U.S. dollar functional currency.*

The Company's other financial instruments that are not related to derivatives, contingent consideration or hedging activities are included in cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, short-term debt, long-term debt, contribution payable, and portions of other assets and other long-term liabilities. These financial instruments are classified as loans and receivables or other financial liabilities and are carried at amortized cost. Excluding long-term debt, the carrying values of these financial instruments and cash and cash equivalents approximate their fair values.

The fair value of long-term debt represents the present value of future cash flows associated with the debt. Market information, such as treasury rates and credit spreads, are used to determine the appropriate discount rates. These fair value determinations are compared to quotes received from financial institutions to ensure reasonability. At December 31, 2017, the carrying value of the Company's long-term debt was $5.2 billion and the estimated fair value was $5.6 billion (December 31, 2016 carrying value of $5.1 billion, estimated fair value of $5.5 billion).

The estimation of the fair value of commodity derivatives and held-for-trading inventories incorporates exit prices and adjustments for quality and location. The estimation of the fair value of interest rate and foreign currency derivatives incorporates forward market prices, which are compared to quotes received from financial institutions to ensure reasonability. The estimation of the fair value of the net investment hedge incorporates foreign exchange rates and market interest rates from financial institutions. All financial assets and liabilities are classified as Level 2 measurements.

Risk Management Overview

The Company is exposed to risks related to the volatility of commodity prices, foreign exchange rates and interest rates. It is also exposed to financial risks related to liquidity and credit and contract risks. In certain instances, the Company uses derivative instruments to manage the Company's exposure to these risks. Derivative instruments are recorded at fair value in accounts receivable, inventory, other assets and accounts payable and accrued liabilities in the consolidated balance sheets. The Company has crude oil and natural gas inventory held in storage related to commodity price risk management contracts that is recognized at fair value. The Company employs risk management strategies and policies designed to ensure that any exposures to risk are in compliance with the Company's business objectives and risk tolerance levels.

Responsibility for risk management is held by the Company's Board of Directors and is implemented and monitored by senior management within the Company.

a) Market Risk

i) Commodity Price Risk Management

All derivative instruments, other than those designated as effective hedging instruments or certain non-financial derivative contracts that meet the Company's own use requirements, are classified as held for trading and are recorded at fair value. Gains and losses on these instruments are recorded in the consolidated statements of income in the period they occur.

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 Exchange Risk Management

The Company's results are affected by the exchange rates between various currencies, including the Canadian and U.S. dollar. The majority of the Company's revenues are received in U.S. dollars or 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. The majority of the Company's expenditures are in Canadian dollars. The Company enters into short-dated foreign exchange contracts to fix the exchange rate for conversion of U.S. revenue dollars to hedge against these fluctuations and to mitigate its exposure to foreign exchange risk.

A change in the value of the Canadian dollar against the U.S. dollar will also result in an increase or decrease in the Company's U.S. dollar denominated debt, as expressed in Canadian dollars, as well as the related finance expense. In order to mitigate the Company's exposure to long-term debt affected by the U.S./Canadian dollar exchange rate, the Company may enter into cash flow hedges using cross currency debt swap arrangements. In addition, the Company's U.S. dollar denominated debt has been designated as a hedge of a net investment in a foreign operation that has a U.S. dollar functional currency. The unrealized foreign exchange gain or loss related to this hedge is recorded in OCI.

At December 31, 2017, the Company had designated US$2.7 billion denominated debt as a hedge of the Company's selected net investments in its foreign operations with a U.S. dollar functional currency (December 31, 2016 – US$3.0 billion). For the year ended December 31, 2017, the unrealized gain arising from the translation of the debt was $243 million (December 31, 2016 – unrealized gain of $113 million), net of tax loss of $38 million (December 31, 2016 – loss of $17 million), which was recorded in hedge of net investment within OCI.

Interest Rate Risk Management

Interest rate risk is the impact of fluctuating interest rates on earnings, cash flows and valuations. To mitigate risk related to interest rates, the Company may enter into fair value or cash flow hedges using interest rate swaps.

At December 31, 2017, the balance in long-term debt related to deferred gains resulting from unwound interest rate swaps that had previously been designated as a fair value hedge was less than $1 million (December 31, 2016 – $2 million). The amortization of the accrued gain upon terminating the interest rate swaps resulted in an offset to finance expenses of $1 million for the year ended December 31, 2017 (December 31, 2016 – $2 million).

At December 31, 2017, the balance in other reserves related to the accrued gain from unwound forward starting interest rate swaps designated as a cash flow hedge was $15 million (December 31, 2016 – $18 million), net of tax of $5 million (December 31, 2016 –net of tax of $6 million). The amortization of the accrued gain upon settling the interest rate swaps resulted in an offset to finance expense of $2 million for the year ended December 31, 2017 (December 31, 2016 – $2 million).

ii) Earnings Impact of Market Risk Management Contracts

The realized and unrealized gains (losses) recognized on other risk management positions for the years ended December 31, 2017 and 2016 are set out below:

Earnings Impact

	2017		
($ millions)	**Marketing and Other**	Other –Net	**Net Foreign Exchange**
Commodity Price			
Natural gas	**(18)**	**—**	**—**
Crude oil	**(28)**	**—**	**—**
	(46)	**—**	**—**
Foreign Currency			
Foreign currency forwards	**—**	**—**	**(30)**
	(46)	—	**(30)**

Earnings Impact

	2016		
($ millions)	Marketing and Other	Other –Net	Net Foreign Exchange
Commodity Price			
Natural gas	(1)	—	—
Crude oil	(38)	—	—
Crude oil call options	—	(67)	—
Crude oil put options	—	(54)	—
	(39)	(121)	—
Foreign Currency			
Foreign currency forwards	—	—	10
	(39)	(121)	10

Offsetting Financial Assets and Liabilities

The tables below outline the financial assets and financial liabilities that are subject to set-off rights and related arrangements, and the effect of those rights and arrangements on the consolidated balance sheets:

Offsetting Financial Assets and Liabilities

($ millions)	**As at December 31, 2017** Gross Amount	Amount Offset	Net Amount
Financial Assets			
Financial derivatives	**150**	**(111)**	**40**
Normal purchase and sale agreements	**639**	**(280)**	**359**
End of year	**789**	**(391)**	**399**
Financial Liabilities			
Financial derivatives	**(246)**	**122**	**(123)**
Normal purchase and sale agreements	**(933)**	**353**	**(581)**
End of year	**(1,179)**	**475**	**(704)**

Offsetting Financial Assets and Liabilities

($ millions)	As at December 31, 2016 Gross Amount	Amount Offset	Net Amount
Financial Assets			
Financial derivatives	57	(38)	19
Normal purchase and sale agreements	529	(199)	330
End of year	586	(237)	349
Financial Liabilities			
Financial derivatives	(161)	70	(91)
Normal purchase and sale agreements	(644)	234	(410)
End of year	(805)	304	(501)

Market Risk Sensitivity Analysis

A sensitivity analysis for commodities, foreign currency exchange and interest rate risks has been calculated by increasing or decreasing commodity prices, foreign currency exchange rates or interest rates, as appropriate. These sensitivities represent the increase or decrease in earnings before income taxes resulting from changing the relevant rates, with all other variables held constant. These sensitivities have only been applied to financial instruments held at fair value. The Company's process for determining these sensitivities has not changed during the year.

Commodity Price Risk[(1)]

($ millions)	10% price increase	10% price decrease
Crude oil price	(10)	10
Natural gas price	(8)	8

Foreign Exchange Rate[(2)]

($ millions)	Canadian dollar $0.01 increase	Canadian dollar $0.01 decrease
U.S. dollar per Canadian dollar	1	(1)

(1) *Based on average crude oil and natural gas market prices as at December 31, 2017.*
(2) *Based on the U.S./Canadian dollar exchange rate as at December 31, 2017.*

b) Financial Risk

i) Liquidity Risk Management

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 processes for managing liquidity risk include 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 Company prepares annual capital expenditure budgets, which are monitored and updated as required. In addition, the Company requires authorizations for expenditures on projects, which assists with the management of capital.

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. The Company's Upstream capital programs are funded principally by cash provided from operating activities and issuances of debt and equity. 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 of 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. Occasionally, the Company will economically hedge a portion of its production to protect cash flow in the event of commodity price declines.

The Company had the following available credit facilities as at December 31, 2017:

Credit Facilities

($ millions)	Available	Unused
Operating facilities(1) *(note 13)*	**850**	**428**
Syndicated bank facilities(2) *(note 15)*	**4,000**	**3,800**
End of year	**4,850**	**4,228**

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

In addition to the credit facilities listed above, the Company had unused capacity under the Canadian Shelf Prospectus of $3.0 billion and unused capacity under the U.S Shelf Prospectus and related U.S registration statement of US$3.0 billion. The ability of the Company to raise additional capital utilizing these Shelf Prospectuses is dependent on market conditions.

The Company believes it has sufficient funding through the use of these facilities and access to the capital markets to meet its future capital requirements.

ii) Credit and Contract Risk Management

Credit and contract risk represent the financial loss that the Company would suffer if a counterparty in a transaction fails to meet its obligations in accordance with the agreed terms. The Company actively manages its exposure to credit and contract execution risk from both a customer and a supplier perspective. The Company's accounts receivables are broad based with customers in the energy industry and midstream and end user segments and are subject to normal industry risks. The Company's policy to mitigate credit risk includes granting credit limits consistent with the financial strength of the counterparties and customers, requiring financial assurances as deemed necessary, reducing the amount and duration of credit exposures and close monitoring of all accounts. The Company had one external customer that constituted more than 10 percent of gross revenues during the years ended December 31, 2017 and December 31, 2016. Sales to this customer were approximately $3,290 million for the year ended December 31, 2017 (December 31, 2016 – $1,832 million).

Cash and cash equivalents include cash bank balances and short-term deposits maturing in less than three months. The Company manages the credit exposure related to short-term investments by monitoring exposures daily on a per issuer basis relative to predefined investment limits.

The carrying amounts of cash and cash equivalents, accounts receivable and restricted cash represent the Company's maximum credit exposure.

The Company's accounts receivable was aged as follows at December 31, 2017:

Accounts Receivable Aging

($ millions)	**December 31, 2017**
Current	**1,161**
Past due (1 – 30 days)	**5**
Past due (31 – 60 days)	**15**
Past due (61 – 90 days)	**1**
Past due (more than 90 days)	**38**
Allowance for doubtful accounts	**(34)**
	1,186

The Company recognizes a valuation allowance when collection of accounts receivable is in doubt. Accounts receivable are impaired directly when collection of accounts receivable is no longer expected. For the year ended December 31, 2017, the Company wrote off $1 million (December 31, 2016 – $3 million) of uncollectible receivables.

Note 25 Related Party Transactions

The following table lists the Company's significant subsidiaries and jointly-controlled entities and their respective places of incorporation, continuance or organization, as the case may be, and the Company's percentage equity interest (to the nearest whole number) as at December 31, 2017. All of the entities listed below, except as otherwise indicated, are 100 percent beneficially owned, or controlled or directed, directly or indirectly, by the Company.

Significant Subsidiaries and Joint Operations	%	Jurisdiction
Husky Oil Operations Limited	100	Alberta
Husky Energy International Corporation	100	Alberta
Lima Refining Company	100	Delaware
Husky Marketing and Supply Company	100	Delaware
Husky Oil Limited Partnership	100	Alberta
Husky Terra Nova Partnership	100	Alberta
Husky Downstream General Partnership	100	Alberta
Husky Energy Marketing Partnership	100	Alberta
Sunrise Oil Sands Partnership	50	Alberta
BP-Husky Refining LLC	50	Delaware

Each of the related party transactions described below was made on terms equivalent to those that prevail in arm's length transactions.

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 (December 31, 2016 – $133 million) related to construction and management services. For the year ended December 31, 2017, the Company had purchases from HMLP of $203 million (December 31, 2016 – $79 million) related to the use of the pipeline for the Company's blending activities, transportation and storage activities, received distributions of $25 million (December 31, 2016 – nil) and paid capital contributions of $17 million (December 31, 2016 – nil). As at December 31, 2017, the Company had $67 million due from HMLP (December 31, 2016 – $26 million).

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 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 (December 31, 2016 – $41 million). For the year ended December 31, 2017, the amount of steam purchased by the Company from Meridian totalled $15 million (December 31, 2016 – $13 million). For the year ended December 31, 2017, the total cost recovery by the Company for facilities services was $11 million (December 31, 2016 – $12 million). At December 31, 2017 the Company had $1 million due from Meridian with respect to these transactions (December 31, 2016 – under $1 million).

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.

Key management includes Directors (executive and non-executive), Executive Officers and Senior Vice – Presidents of the Company. The amounts disclosed in the table below are the amounts recognized as an expense during the reporting period related to key management personnel:

Compensation of Key Management Personnel

($ millions)	**2017**	2016
Short-term employee benefits[(1)]	**16**	16
Stock-based compensation[(2)]	**31**	22
	47	38

(1) Short-term employee benefits are comprised of salary and benefits earned during the year, plus cash bonuses awarded during the year. Annual bonus awards settled in shares are included in stock-based compensation expense.

(2) Stock-based compensation expense represents the cost to the Company for participation in share-based payment plans.

Note 26 Commitments and Contingencies

At December 31, 2017, the Company had commitments that require the following minimum future payments, which are not accrued in the consolidated balance sheets:

Minimum Future Payments for Commitments

($ millions)	Within 1 year	After 1 year but not more than 5 years	More than 5 years	Total
Operating leases[(1)]	164	477	1,540	2,181
Firm transportation agreements[(1)]	451	1,874	4,306	6,631
Unconditional purchase obligations[(2)]	1,965	5,258	6,675	13,898
Lease rentals and exploration work agreements	94	275	973	1,342
Obligations to fund equity investee[(3)]	51	272	451	774
	2,725	8,156	13,945	24,826

(1) Included in 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.

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

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 the outcome of adverse decisions in any pending or threatened proceedings related to these and other matters would have a material adverse impact on its financial position, results of operations or liquidity.

Note 27 Capital Disclosures

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 as 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. Debt to capital employed is defined as long-term debt, long-term debt due within one year, and short-term debt divided by capital employed which is equal to long-term debt, long-term debt due within one year, short-term debt and shareholders' equity. Debt to funds from operations is defined as long-term debt, long-term debt due within one year and short-term debt divided by funds from operations which is equal to cash flow – operating activities plus change in non-cash working capital.

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) which was within the Company's target and debt to funds from operations was 1.6 times (December 31, 2016 – 2.4 times), which was within Company's target. 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.

The Company's share capital is not subject to external restrictions; however, the syndicated credit facilities include a debt to capital covenant, 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.

There were no changes in the Company's approach to capital management from the previous year.

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 prodution 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.

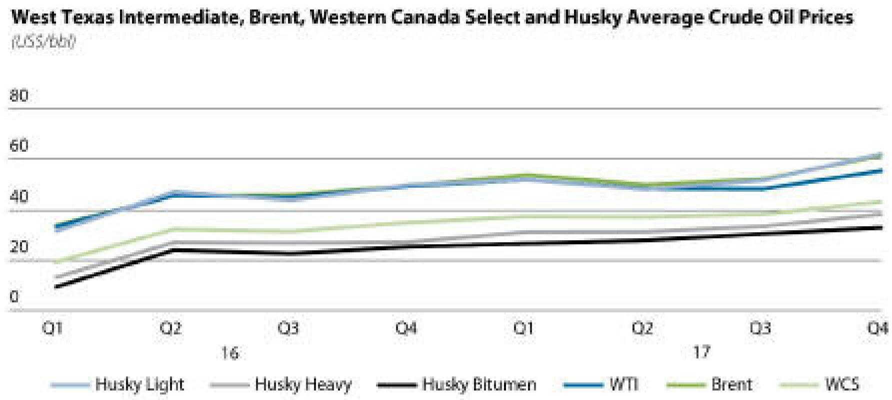
Average Benchmarks Summary		2017	2016
West Texas Intermediate ("WTI") crude oil[(1)]	*(US$/bbl)*	**50.95**	43.32
Brent crude oil[(2)]	*(US$/bbl)*	**54.28**	43.69
Light sweet at Edmonton	*($/bbl)*	**62.91**	52.99
Daqing[(3)]	*(US$/bbl)*	**51.78**	40.86
Western Canada Select at Hardisty[(4)]	*(US$/bbl)*	**38.98**	29.48
Lloyd heavy crude oil at Lloydminster	*($/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

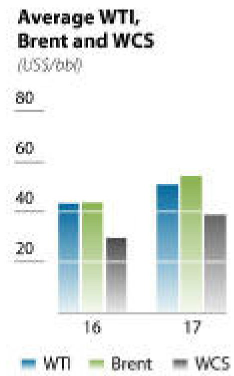
(1) *Calendar Month Average of settled prices for West Texas Intermediate at Cushing, Oklahoma.*
(2) *Calendar Month Average of settled prices for Dated Brent.*
(3) *Calendar Month Average of settled prices for Daqing.*
(4) *Western Canadian Select is a heavy blended crude oil, comprised of conventional 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



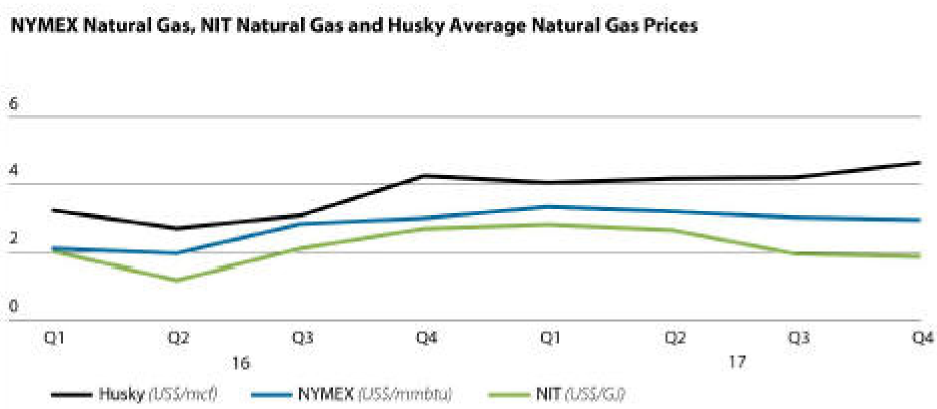


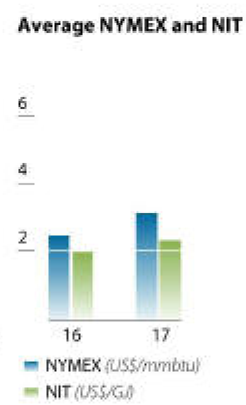
Global crude oil benchmarks strengthened in 2017 primarily due to the production reductions made by certain members of OPEC and some key non-OPEC producers, along with global demand growth of an estimated 1.6 mmboe/day per the EIA. The production cuts were partially offset by increased production from 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



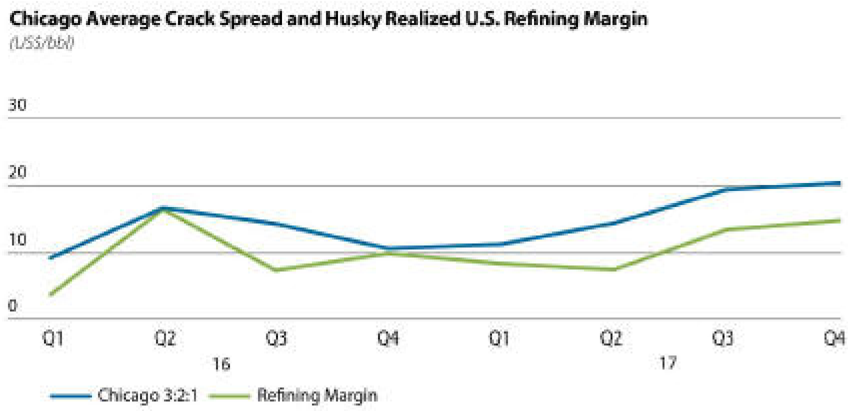


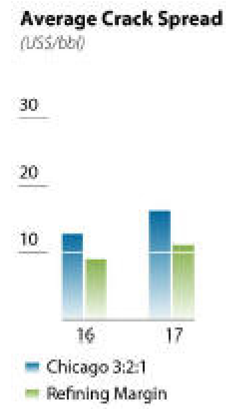
North American natural gas benchmarks continued to be weak in 2017 due to the continued oversupply of natural gas in North America. The oversupply is largely the result of technological advances in horizontal drilling and hydraulic fracturing that have unlocked significant reserves that were not economical 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



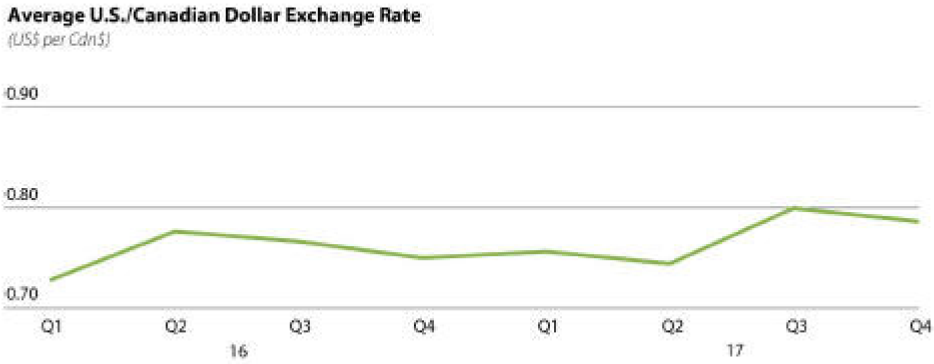


The Chicago 3:2:1 crack spread is the key indicator for U.S. refining margins and reflects refinery gasoline output that is approximately twice the distillate output, and is calculated as the price of two-thirds of a barrel of gasoline plus one-third of a barrel of distillate fuel less one barrel of 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 ($ millions)	Earnings (Loss) before Income Taxes 2017	2016	Net Earnings (Loss) 2017	2016	Capital Expenditures[1] 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

Gross Production	Guidance 2018	**Year ended December 31** 2017	Guidance 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.

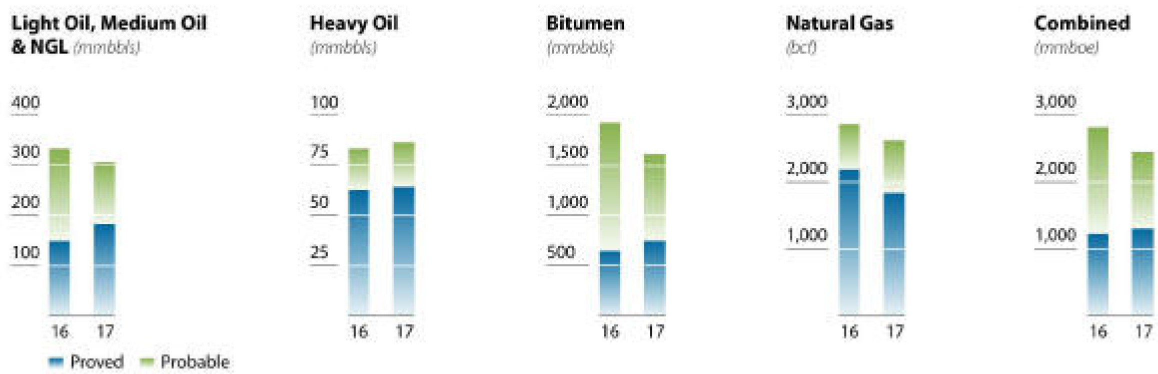
The Company has budgeted $750 - $775 million in Atlantic for 2018, primarily for the construction of the West White Rose Project.

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.

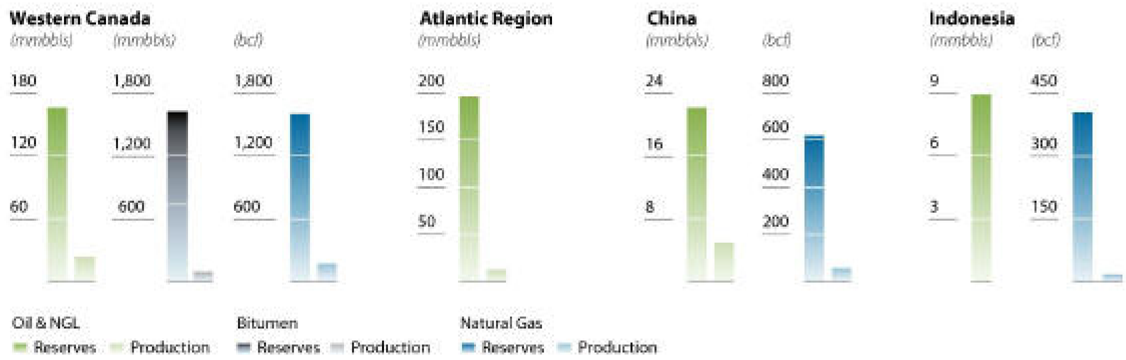
The Company's complete oil and gas reserves disclosure, prepared in accordance with NI 51-101 is contained in the Company's Annual Information Form, which is available at www.sedar.com, and certain supplementary oil and gas reserves disclosure prepared in accordance with U.S. disclosure requirements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

	Three months ended	
($ millions, except where indicated)	**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

($ millions, except where indicated)	Three months ended 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**

	Upstream								Downstream			
	Exploration and Production[1]				Infrastructure and Marketing				Upgrading			
2016 *($ millions)*	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

Exhibit No.	Description
23.1	Consent of KPMG LLP, independent registered public accounting firm.
23.2	Consent of Sproule Associates Limited, independent engineers.
23.3	Consent of Richard Leslie, P. Eng, internal qualified reserves evaluator.
31.1	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
31.2	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or 15d-14(a) of the Securities Exchange Act of 1934.
32.1	Certification of Chief Executive Officer pursuant to Rule 13(a)-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
32.2	Certification of Chief Financial Officer pursuant to Rule 13(a)-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code (18 U.S.C. 1350).
99.1	Supplemental Disclosures of Oil and Gas Activities.
99.2	Amended Code of Business Conduct.
101	Interactive Data File.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document.

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors of Husky Energy Inc.

We consent to the incorporation by reference in the registration statements on Form S-8 (File No. 333-187135) and Form F-10 (File No. 333-222652) of Husky Energy Inc. of:

- our independent auditors' report dated February 28, 2018, with respect to the consolidated balance sheets of Husky Energy Inc. as at December 31, 2017 and December 31, 2016, the consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information;
- our independent auditors' report of registered public accounting firm dated February 28, 2018, with respect to the consolidated balance sheets of Husky Energy Inc. as at December 31, 2017 and December 31, 2016, the consolidated statements of income, comprehensive income, changes in shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information; and
- our report of independent registered public accounting firm dated February 28, 2018 on the effectiveness of internal control over financial reporting as at December 31, 2017,

which reports appear in the annual report on Form 40-F of Husky Energy Inc. for the fiscal year ended December 31, 2017, and further consent to the use of such reports in such annual report on Form 40-F.

/s/ KPMG LLP
KPMG LLP

Chartered Professional Accountants
Calgary, Canada
February 28, 2018

Exhibit 23.2

Consent of Independent Engineers

We refer to our report auditing estimates of the natural gas, natural gas liquids and oil reserves attributable to Husky Energy Inc. (the "Company") as of December 31, 2017 (the "Report").

We hereby consent to the use and reference to our name and the Report described or incorporated by reference in the Company's Annual Report on Form 40-F for the year ended December 31, 2017 and the Company's registration statements on Form S-8 (File No. 333-187135) and Form F-10 (File No. 333-222652), filed with the U.S. Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, or the Securities Act of 1933, as amended, as applicable.

Sincerely,

Sproule Associates Limited

/s/ Cameron P. Six, P. Eng.
Cameron P. Six, P.Eng.
Vice President Engineering, Chief Engineer and Director

March 1 , 2018
Calgary, Alberta, Canada

Exhibit 23.3

Consent of Internal Qualified Reserves Evaluator

I, Richard Leslie, hereby consent to the incorporation by reference in the Annual Report on Form 40-F of Husky Energy Inc. for the year ended December 31, 2017, which is being filed with the U.S. Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended, of my Report on Reserves Data dated January 31, 2018 (the "Report"), included in the 2017 Annual Information Form of Husky Energy Inc. (the "AIF"), and to the references to my name in the AIF. I also hereby consent to the incorporation by reference of the Report in the Company's registration statements on Form S-8 (File No. 333-187135) and Form F-10 (File No. 333-222652) filed with the U.S. Securities and Exchange Commission pursuant to the Securities Act of 1933, as amended. I have signed this Consent in my capacity as an employee of Husky Energy Inc. and not in my personal capacity.

By: /s/ Richard Leslie, P.Eng
Richard Leslie, P. Eng
Manager, Reserves
Internal Qualified Reserves Evaluator

Calgary, Alberta, Canada
March 1, 2018

Exhibit 31.1

**Certification Pursuant to
Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934,
As Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002**

I, Robert J. Peabody, certify that:

1. I have reviewed this annual report on Form 40-F of Husky Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

   a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

   c. Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d. Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's Board of Directors (or persons performing the equivalent functions):

   a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

   b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 1, 2018

/s/ Robert J. Peabody
Robert J. Peabody
President & Chief Executive Officer

Exhibit 31.2

Certification Pursuant to
Rule 13a-14 or 15d-14 of the Securities Exchange Act of 1934,
As Adopted Pursuant to
Section 302 of the Sarbanes-Oxley Act of 2002

I, Jonathan M. McKenzie, certify that:

1. I have reviewed this annual report on Form 40-F of Husky Energy Inc.;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4. The issuer's other certifying officer(s) and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

    a. Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b. Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

    c. Evaluated the effectiveness of the issuer's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d. Disclosed in this report any change in the issuer's internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer's internal control over financial reporting; and

5. The issuer's other certifying officer(s) and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer's auditors and the audit committee of the issuer's Board of Directors (or persons performing the equivalent functions):

    a. All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer's ability to record, process, summarize and report financial information; and

    b. Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer's internal control over financial reporting.

Date: March 1, 2018

/s/ Jonathan M. McKenzie
Jonathan M. McKenzie
Chief Financial Officer

Exhibit 32.1

Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Husky Energy Inc. (the "Company") on Form 40-F for the fiscal year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), **I, Robert J. Peabody, President & Chief Executive Officer of the Company**, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2018

/s/ Robert J. Peabody
Robert J. Peabody
President & Chief Executive Officer

Certification Pursuant to
18 U.S.C. Section 1350,
As Adopted Pursuant to
Section 906 of the Sarbanes-Oxley Act of 2002

In connection with the Annual Report of Husky Energy Inc. (the "Company") on Form 40-F for the fiscal year ended December 31, 2017 as filed with the Securities and Exchange Commission on the date hereof (the "Report"), **I, Jonathan M. McKenzie, Chief Financial Officer of the Company**, certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that:

1. The Report fully complies with the requirements of section 13(a) or 15(d) of the Securities Exchange Act of 1934; and
2. The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

Date: March 1, 2018

/s/ Jonathan M. McKenzie
Jonathan M. McKenzie
Chief Financial Officer

Disclosure about Oil and Gas Producing Activities - Accounting Standards Codification 932, "Extractive Activities - Oil and Gas" (unaudited)

The following disclosures have been prepared in accordance with FASB Accounting Standards Codification 932, "Extractive Activities - Oil and Gas".

The unaudited supplemental information on oil and gas exploration and production activities for 2017 and 2016 has been presented in accordance with the revised reserve estimation and disclosure rules, which were not applied retrospectively.

Oil and Gas Reserves

Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations.

Proved developed oil and gas reserves are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

Canadian provincial royalties are determined based on a graduated percentage scale, which varies with prices and production volumes. Canadian reserves, as presented on a net basis, assume prices and royalty rates in existence at the time the estimates were made, and Husky's estimate of future production volumes. Future fluctuations in prices, production rates, or changes in political or regulatory environments could cause Husky's share of future production from Canadian reserves to be materially different from that presented.

Subsequent to December 31, 2017, no major discovery or other favourable or adverse event is believed to have caused a material change in the estimates of developed or undeveloped reserves as of that date.

Note that the numbers in each column of the tables throughout this exhibit may not add due to rounding.

Results of Operations for Producing Activities[1] (unaudited)

($ millions)	Year Ended December 31, 2017 Canada	China	Indonesia[2]	Total
Revenues, net of Royalties	3,584	1,013	39	4,636
Production and Operating Expenses	1,547	94	9	1,650
Depreciation, Depletion, Amortization & Impairment	1,863	386	12	2,261
Exploration & Evaluation Expenses	54	4	1	59
Earnings Before Taxes	120	529	17	666
Income Taxes Expense	33	132	7	172
Results of Operations	**87**	**397**	**10**	**494**

($ millions)	Year Ended December 31, 2016 Canada	China	Indonesia[2]	Total
Revenues, net of Royalties	2,784	756	—	3,540
Production and Operating Expenses	1,617	92	—	1,709
Depreciation, Depletion, Amortization & Impairment	1,444	363	—	1,807
Exploration & Evaluation Expenses	75	—	—	75
Earnings (Loss) Before Taxes	(352)	301	—	(51)
Income Taxes Expense (Recovery)	(96)	75	—	(21)
Results of Operations	**(256)**	**226**	**—**	**(30)**

(1) The costs in this schedule exclude corporate overhead, interest expense and other operating costs, which are not directly related to producing activities.

(2) Revenue and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.

Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities (unaudited)

($ millions)	Canada	China	Indonesia[1]	Total
2017				
Property Acquisition				
Unproved	55	—	—	55
Proved	18	—	—	18
Exploration	157	10	—	167
Development	1,394	10	50	1,454
Total Costs Incurred	**1,624**	**20**	**50**	**1,694**
2016				
Property Acquisition				
Unproved	—	—	—	—
Proved	7	—	—	7
Exploration	59	4	—	63
Development	945	106	139	1,190
Total Costs Incurred	1,011	110	139	1,260

(1) Capital expenditures related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.

Acquisition costs include costs incurred to purchase, lease or otherwise acquire oil and gas properties.

Exploration costs include the costs of geological and geophysical activity, retaining undeveloped properties and drilling and equipping exploration wells.

Development costs include the costs of (i) drilling and equipping development wells and (ii) facilities to extract, treat, gather and store oil and gas.

Exploration and development costs include administrative costs and depreciation of support equipment directly associated with these activities.

The following table sets forth a summary of oil and gas property costs not being amortized at December 31, 2017, by the year in which the costs were incurred:

Withheld Costs (unaudited)

($ millions)	Total	2017	2016	Prior to 2015
Property Acquisitions				
Canada	127	65	5	57
China	—	—	—	—
Indonesia[1]	—	—	—	—
Total Property Acquisitions	127	65	5	57
Exploration				
Canada	761	151	89	521
China	7	7	—	—
Indonesia[1]	9	2	4	3
Total Exploration	777	160	93	524
Development				
Canada	1,429	1,062	367	—
China	307	7	67	233
Indonesia[1]	113	21	92	—
Total Development	1,849	1,090	526	233
Capitalized Interest				
Canada	70	28	13	29
China	112	19	20	73
Indonesia[1]	30	2	16	12
Total Capitalized Interest	212	49	49	114
Total Withheld Costs	**2,965**	**1,364**	**673**	**928**

(1) Capital expenditures related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.

Capitalized Costs Relating to Oil and Gas Producing Activities (unaudited)

($ millions)	Canada	China	Indonesia[1]	Total
2017				
Proved Properties[2]	36,802	5,003	788	42,593
Unproved Properties	831	7	9	847
	37,633	5,010	797	43,440
Accumulated DD&A, including impairments	(24,017)	(1,997)	(11)	(26,025)
Net Capitalized Costs	**13,616**	**3,013**	**786**	**17,415**
2016				
Proved Properties[2]	39,916	4,875	362	45,153
Unproved Properties	653	412	43	1,108
	40,569	5,287	405	46,261
Accumulated DD&A, including impairments	(26,250)	(1,735)	—	(27,985)
Net Capitalized Costs	**14,319**	**3,552**	**405**	**18,276**

(1) Capital expenditures related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.
(2) Capitalized costs related to proved properties include ARO costs. The gross ARO for the years presented were as follows:

($ millions)	Canada	China	Indonesia[1]	Total
2017	**1,907**	**214**	**17**	**2,138**
2016	2,245	224	—	2,469

(1) ARO costs related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.

Oil and Gas Reserve Information

In Canada, Husky's proved crude oil, NGL and natural gas reserves are located in the provinces of Alberta, Saskatchewan, British Columbia, and offshore East Coast of Canada. Husky's international proved reserves are located in China and Indonesia. Please note that the bitumen reserves have been separated from crude oil and prior years have been restated to account for the change in disclosure only.

	Canada				China			
Reserves	**Crude Oil** *(mmbbls)*	**Bitumen** *(mmbbls)*	**NGL** *(mmbbls)*	**Natural Gas** *(bcf)*	**Crude Oil** *(mmbbls)*	**Bitumen** *(mmbbls)*	**NGL** *(mmbbls)*	**Natural Gas** *(bcf)*
Net Proved Reserves[(1)(2)(3)(4)]								
End of Year 2014	283	360	49	1,948	6	—	10	335
Revisions	(57)	(202)	(12)	(490)	1	—	4	48
Purchases	—	—	—	7	—	—	—	—
Sales	(4)	—	—	(6)	—	—	—	—
Improved Recovery	1	—	—	—	—	—	—	—
Discoveries and Extensions	2	91	1	109	—	—	—	—
Production	(46)	(21)	(3)	(179)	(3)	—	(3)	(60)
End of Year 2015	180	227	35	1,389	4	—	11	323
Revisions	4	42	3	(23)	—	—	4	94
Purchases	—	3	—	8	—	—	—	—
Sales	(50)	—	—	(58)	—	—	—	—
Improved Recovery	—	—	—	1	—	—	—	—
Discoveries and Extensions	2	16	—	11	—	—	—	—
Production	(36)	(34)	(3)	(155)	(2)	—	(2)	(39)
End of Year 2016	100	254	35	1,173	2	—	13	378
Revisions	43	375	—	214	—	—	3	52
Purchases	—	—	—	—	—	—	—	—
Sales	(10)	—	(1)	(283)	—	—	—	—
Improved Recovery	20	102	—	—	—	—	—	—
Discoveries and Extensions	44	27	1	90	—	—	—	—
Production	(30)	(41)	(3)	(130)	(2)	—	(3)	(52)
End of Year 2017	**167**	**717**	**32**	**1,063**	**—**	**—**	**13**	**378**
Net Proved Developed Reserves[(1)(2)(3)(4)]								
End of Year 2014	243	113	39	1,476	6	—	10	335
End of Year 2015	167	97	32	1,116	4	—	11	323
End of Year 2016	98	104	34	986	2	—	13	378
End of Year 2017	**110**	**154**	**28**	**735**	**—**	**—**	**13**	**378**
Net Proved Undeveloped Reserves[(1)(2)(3)(4)]								
End of Year 2014	40	247	10	472	—	—	—	—
End of Year 2015	13	130	2	273	—	—	—	—
End of Year 2016	2	150	1	187	—	—	—	—
End of Year 2017	**57**	**563**	**4**	**328**	**—**	**—**	**—**	**—**

Reserves	Indonesia[5] Crude Oil (mmbbls)	Indonesia[5] Bitumen (mmbbls)	Indonesia[5] NGL (mmbbls)	Indonesia[5] Natural Gas (bcf)	Total[6] Crude Oil (mmbbls)	Total[6] Bitumen (mmbbls)	Total[6] NGL (mmbbls)	Total[6] Natural Gas (bcf)	Total Company (mmboe)
Net Proved Reserves[1][2][3][4]									
End of Year 2014	—	—	5	123	289	360	64	2,406	1,113
Revisions	—	—	—	5	(56)	(202)	(8)	(437)	(339)
Purchases	—	—	—	—	—	—	—	7	2
Sales	—	—	—	—	(4)	—	—	(6)	(5)
Improved Recovery	—	—	—	—	1	—	—	—	1
Discoveries and Extensions	—	—	—	74	2	91	1	183	125
Production	—	—	—	—	(49)	(21)	(6)	(239)	(116)
End of Year 2015	—	—	5	202	184	227	51	1,914	781
Revisions	—	—	—	6	4	42	7	77	66
Purchases	—	—	—	—	—	3	—	8	4
Sales	—	—	—	—	(50)	—	—	(58)	(60)
Improved Recovery	—	—	—	—	—	—	—	1	1
Discoveries and Extensions	—	—	—	—	2	16	—	11	20
Production	—	—	—	—	(38)	(34)	(5)	(194)	(109)
End of Year 2016	—	—	5	208	102	254	53	1,759	703
Revisions	—	—	—	(20)	43	375	3	245	461
Purchases	—	—	—	—	—	—	—	—	—
Sales	—	—	—	—	(10)	—	(1)	(283)	(58)
Improved Recovery	—	—	—	—	20	102	—	—	122
Discoveries and Extensions	—	—	—	—	44	27	1	90	87
Production	—	—	—	(3)	(32)	(41)	(6)	(185)	(110)
End of Year 2017	**—**	**—**	**5**	**185**	**167**	**717**	**50**	**1,626**	**1,205**
Net Proved Developed Reserves[1][2][3][4]									
End of Year 2014	—	—	—	—	249	113	49	1,811	713
End of Year 2015	—	—	—	—	171	97	44	1,439	551
End of Year 2016	—	—	5	133	100	104	52	1,497	506
End of Year 2017	**—**	**—**	**5**	**117**	**110**	**154**	**47**	**1,230**	**516**
Net Proved Undeveloped Reserves[1][2][3][4]									
End of Year 2014	—	—	5	123	40	247	15	595	400
End of Year 2015	—	—	5	202	13	130	7	475	230
End of Year 2016	—	—	—	75	2	150	1	262	197
End of Year 2017	**—**	**—**	**—**	**68**	**57**	**563**	**3**	**396**	**689**

(1) Net reserves are the Company's lessor royalty, overriding royalty and working interest share of the gross remaining reserves, after deduction of any crown, freehold and overriding royalties. Such royalties are subject to change by legislation or regulation and can also vary depending on production rates, selling prices and timing of initial production.

(2) Reserves are the estimated remaining quantities of oil and gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations.

(3) Proved oil and gas reserves are those quantities of oil and gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations.

(4) Proved developed oil and gas reserves are proved reserves that can be expected to be recovered: (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well. Proved undeveloped oil and gas reserves are proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(5) Husky's beneficial interest in Indonesia and the Madura Strait Block is held by way of a 40 percent interest in Husky—CNOOC Madura Limited ("HCML"), an entity that is party to a PSC with the Government of Indonesia. Husky has entered into a unanimous shareholder agreement dated April 8, 2008 with the other shareholders of HCML that provides for joint control of HCML. International Financial Reporting Standard 11, "Joint Arrangements" ("IFRS 11"), requires Husky to follow the equity method of accounting for its investment in the Madura Strait Block. IFRS 11 focuses on the legal form of the corporate structure in which Husky's Madura assets are held. Husky holds its interest in the Madura Strait Block through HCML and accordingly is required to use the equity method to account for this interest. As a consequence, Husky has disclosed Indonesia as a separate entity in the above disclosure because the Madura Strait Block is accounted for by the equity method of accounting.

(6) In addition to the major changes to proved reserves in 2017 described under "Oil and Gas Reserves Disclosures—Reconciliation of Gross Proved Reserves" in Document A—Annual Information Form, bitumen reserves in Sunrise were economic under SEC price forecasts as of December 31, 2017 (they were uneconomic in 2015 and 2016) and account for the vast majority of the revisions in 2017.

The Company's reserve replacement ratio[1] for the last three years was as follows:

Net Proved Oil and Gas Reserves	2017	2016	2015
Excluding Acquisition & Divestiture	**611%**	80%	(184)%
Including Acquisition & Divestiture	**558%**	29%	(188)%

(1) Reserves replacement ratio is calculated as net reserve additions during the period divided by total production during the period. Net reserves additions include: revisions, purchases, sales, improved recovery, and discoveries and extensions. The negative reserves replacement ratio for 2015 is a result of the Sunrise bitumen reserves becoming uneconomic. SImilarly, the large positive reserves replacement ratio for 2017 is a reflection of the Sunrise bitumen reserves becoming economic again in 2017.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (unaudited)

The following information has been developed utilizing procedures prescribed by FASB Accounting Standards Codification 932, "Extractive Activities - Oil and Gas" and is based on crude oil and natural gas reserve and production volumes estimated by the Company's reserves evaluation staff. It may be useful for certain comparison purposes, but should not be solely relied upon in evaluating Husky or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of Husky's reserves.

The future cash flows presented below are based on average sales prices and cost rates, and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of crude oil and natural gas reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves, and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The computation of the standardized measure of discounted future net cash flows relating to proved oil and gas reserves at December 31, 2017 was based on the New York Mercantile Exchange 2017 average natural gas cash market price of U.S. $2.98/mmbtu (2016 average - U.S. $2.48 mmbtu; 2015 average - U.S. $2.59/mmbtu) and on crude oil prices computed with reference to the 2017 average WTI spot price of U.S. $51.19/ bbl (2016 average - U.S. $42.68/bbl; 2015 average - U.S. $50.20/bbl). Natural gas prices for China and Indonesia reserves are based on various Gas Sales Agreements, are included in the AIF, and were updated as result of price negotiations with various purchasers.

Standardized Measure	Canada[1]			Other International [1][2]			Indonesia [1]			Total [1]		
(unaudited) *($ millions)*	**2017**	2016	2015	**2017**	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Future Cash Inflows	**37,720**	14,423	22,014	**5,707**	5,967	5,044	**2,016**	2,378	2,174	**45,443**	22,768	29,232
Future Production Costs	**17,843**	8,378	11,358	**704**	548	727	**917**	1,140	1,075	**19,464**	10,066	13,160
Future Development Costs	**12,453**	7,118	8,859	**135**	236	499	**89**	118	227	**12,677**	7,472	9,585
Future Income Taxes	**2,021**	(395)	400	**1,342**	648	472	**256**	231	195	**3,619**	484	1,067
Future Net Cash Flows	**5,403**	(678)	1,397	**3,526**	4,535	3,346	**754**	889	677	**9,683**	4,746	5,420
Annual 10% Discount	**2,620**	(1,760)	(1,241)	**884**	1,170	468	**232**	357	363	**3,736**	(233)	(410)
Standardized Measure of Discounted Future Net Cash Flows	2,783	1,082	2,638	2,642	3,365	2,878	522	532	314	5,947	4,979	5,830

(1) The schedules above are calculated using year average prices and year-end costs, statutory income tax rates and existing proved oil and gas reserves for 2015, 2016 and 2017. The value of exploration properties and probable reserves, future exploration costs, future change in oil and gas prices and in production and development costs are excluded.

(2) The schedule above includes China for 2015, 2016 and 2017, and Libya for 2015 and 2016.

Changes in Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves (unaudited)

	Canada [1]			Other International [1][2]			Indonesia [1]			Total [1]		
($ millions)	**2017**	2016	2015	**2017**	2016	2015	**2017**	2016	2015	**2017**	2016	2015
Future discounted net cash flows at beginning of year	**1,082**	2,638	9,820	**3,365**	2,878	3,070	**532**	314	123	**4,979**	5,830	13,013
Sales and transfer, net of production costs	**(1,623)**	(851)	(1,368)	**(864)**	(621)	(1,306)	**(20)**	—	—	**(2,507)**	(1,472)	(2,674)
Net change in sales and transfer prices, net of production costs	**2,845**	(2,435)	(13,374)	**(238)**	317	(115)	**(10)**	56	—	**2,597**	(2,062)	(13,489)
Development cost incurred that reduced												
Future develop. costs	**1,267**	705	1,990	**2**	114	37	**33**	—	39	**1,302**	819	2,066
Changes in estimated future development costs	**(4,135)**	264	2,887	**(38)**	138	3	**17**	108	(38)	**(4,156)**	510	2,852
Extensions, discoveries and improved recovery, net of related costs	**3,006**	193	1,164	**—**	—	—	**—**	—	129	**3,006**	193	1,293
Revisions of quantity estimates	**2,573**	300	(2,472)	**567**	1,180	623	**(64)**	23	21	**3,076**	1,503	(1,828)
Accretion of discount	**100**	299	1,629	**319**	205	339	**72**	57	17	**491**	561	1,985
Sale of reserves in place	**(658)**	(573)	(93)	**—**	—	—	—	—	—	**(658)**	(573)	(93)
Purchase of reserves in place	—	40	4	**—**	—	—	—	—	—	**—**	40	4
Changes in timing of future net cash flows and other	**(621)**	(128)	(231)	**55**	(790)	323	**(19)**	—	44	**(585)**	(918)	136
Net change in income taxes	**(1,053)**	630	2,682	**(526)**	(56)	(96)	**(19)**	(26)	(21)	**(1,598)**	548	2,565
Net Increase (Decrease)	**1,701**	(1,556)	(7,182)	**(723)**	487	(192)	**(10)**	218	191	**968**	(851)	(7,183)
End of Year	**2,783**	1,082	2,638	**2,642**	3,365	2,878	**522**	532	314	**5,947**	4,979	5,830

(1) The schedules above are calculated using year-end average prices and year-end costs, statutory income tax rates and existing proved oil and gas reserves for 2015, 2016, and 2017. The value of exploration properties and probable reserves, future exploration costs, future changes in oil and gas prices and in production and development costs are excluded.

(2) The schedule above includes China for 2015, 2016 and 2017, and Libya for 2015 and 2016.

Exhibit 99.2

Amended Code of Business Conduct (Revised February 2017)

Purpose

Husky Energy Inc. is committed to upholding high standards of business integrity, and seeks to deter wrongdoing and to promote transparent, honest and ethical behaviour in all our business dealings. It is for this reason the Code of Business Conduct (the "Code") was developed.

The Code applies to Husky Energy Inc. and all divisions, subsidiaries and affiliate companies over which it exercises control (collectively, "Husky" or the "Company"). It also applies to all Officers, Directors and employees of Husky, which for these purposes includes Husky temporary or contract staff (hereinafter referred to as "Personnel").

The Code sets out the minimum standards of conduct to which all Personnel are required to adhere. Personnel are to comply with any additional requirements set by their employing company or by local law, which may be stricter than those set out here.

The Code may be modified from time to time. Personnel will be notified of any such changes.

1. General Guidelines for Appropriate Conduct

You, as Personnel, are expected to accept certain responsibilities, adhere to acceptable legal business principles, and exhibit a high degree of personal integrity at all times. You are expected to refrain from behaviour that might be harmful to you, your co-workers, our business associates or the Company. The intent of the Code is not to place unreasonable restrictions on your personal actions, but to set out the standards you are expected to meet in your capacity as Personnel. You are expected to comply with the Code and all Husky policies.

Husky will strive to ensure the activities of our Personnel, contractors and agents are consistent with these principles. Any breach of the Code is considered serious and may result in disciplinary action up to and including the immediate termination of employment for just cause in accordance with the prevailing laws and regulations of the jurisdiction you are in, or the immediate termination of a service contract.

If you have any questions relating to the Code, you are to seek the advice of your Department Manager, the executive responsible for your business unit, or the Legal Department.

2. Compliance with Laws

You must recognize, be familiar with, and comply with the governmental laws, rules, and regulations that apply to Husky's business in the area in which your employing company operates.

3. Diversity and Respectful Workplace

Husky is an equal opportunity employer and is committed to building a work environment that is free of discrimination, harassment and violence by ensuring our employment policies are implemented in a fair and equitable manner and are free of discrimination.

The Company will support and promote the protection of human rights within our sphere of influence. Discrimination based on the categories protected by law in the jurisdiction in which you are employed is strictly prohibited.

All incidents of discrimination, bullying, harassment and violence should be reported. Allegations of discrimination, bullying, violence or harassment are taken seriously and treated in a discrete and timely manner. Husky strictly prohibits retaliatory action in any form against any Personnel who, in good faith, reports a possible violation.

See Diversity and Respectful Workplace Policy 2.02 for further information.

4. Alcohol and Drugs

Husky is committed to providing a safe, healthy and productive work environment. Personnel make a valuable contribution to Husky's success through safe, efficient and conscientious performance of their duties. Personnel are required to be fit for duty when reporting for work and remain fit for duty at all times while at work. All Personnel are required to report any unsafe work, including when Personnel are not fit for duty.

The use of alcohol and/or drugs, including prescription medications that may be mood-altering or impair judgment, may adversely affect job performance, productivity, business decisions and the safety and well being of our people and the communities in which we operate. Personnel are required to declare if they are not fit for duty or are under treatment that may impair performance to ensure the continued safe operation of our business. The nature of treatment or illness does not need to be disclosed.

Personnel who have an alcohol or drug dependency or any concerns related to the use or abuse of alcohol and/or drugs are expected to seek assistance at the earliest opportunity. Assistance and support is provided through the Employee and Family Assistance Program ("EFAP"). EFAP services are completely confidential and offered at no cost to employees and their family members.

See Drug and Alcohol Policy 2.09, Statement of Contractor Requirements and the Employee and Family Assistance Program guideline for further information.

5. Conflicts of Interest and Outside Activities

You must avoid all situations in which your personal interests conflict with your duties to Husky or the interests of the Company. To do so, you must be sensitive to any activities, interests or relationships that might conflict, or even appear to conflict, with your ability to act in the best interests of Husky. You are required to disclose any potential conflict of interest upon commencing work. You must immediately disclose any potential conflicts of interest that arise or you become aware of after starting at Husky to your Department Manager or the executive responsible for your business unit. If the Department Manager or the executive responsible for your business unit is uncertain whether the situation is contrary to Company policy, he or she is expected to consult with Husky's Senior Vice President, Human & Corporate Resources or Senior Vice President, General Counsel & Secretary.

A potential conflict of interest arises any time you or any "related person" engage in any activity that may:

a. Result, directly or indirectly, in you or any related person receiving a benefit from a relationship with Husky, at the expense of Husky, or resulting in a lost opportunity to Husky; or

b. Interfere with your objectivity or effectiveness in performing your duties and responsibilities to Husky.

A "related person" is generally a person with whom you have a close personal relationship, a member of your household, or is financially dependent on you. At a minimum, this includes your spouse, civil partner, and any person living in the same house as you.

Any of the following activities can create conflicts as described further below:

Outside work, employment, or other endeavours:

i. in areas similar to those in which Husky is involved;

ii. for customers, contractors or competitors of Husky; or

iii. that otherwise have the potential to affect your objectivity and work performance.

a. Performing outside work or soliciting outside business on Husky's premises or on Husky's time.

b. Using Husky's equipment or services, materials, resources or proprietary information for outside work.

c. Engaging in any activities that could reflect negatively on the reputation of our Company or our Personnel.

d. Holding any financial interest in, or taking a loan from, a company or organization that is a contractor, customer, partner or competitor of Husky.

The restrictions on relationships with contractors, customers, partners and competitors set out in this section will also apply, as appropriate, to affiliates of those entities.

Unless you have disclosed the matter and obtained approval as set forth above, you should not:

Influence, or seek to influence, a corporate decision in a manner that favours another individual or organization in the expectation of realizing personal gain for yourself, a related person, or others with whom you have or have had an association.

a. Own, either directly or indirectly, a significant financial interest in any contractor, customer, partner or competitor of Husky. A financial interest is significant if the holding is either:

i. 5% or more of the stock, assets or other interests of the contractor, customer, partner or competitor; or

ii. 10% or more of your net assets.

Such financial interest includes significant investments in oil and gas properties and shares or securities of Husky's joint ventures.

b. Own any investments that could materially affect your judgment with respect to Husky's business interests.

c. Act as an officer, director, partner, consultant, representative, agent, advisor or employee of any of the following:

i. A contractor, customer, partner or competitor of Husky;

ii. Any business that is involved in technical areas or product lines that are similar to those of Husky;

iii. Any business whose customers include the Company, our customers or our contractors; or

iv. Any organization that has or seeks business dealings with Husky where there exists (or may appear to exist) an opportunity for special consideration for you or the organization.

d. Accept any directorship, consulting or advisory appointment or engage in any other activity that could create a conflict of interest that may impair Husky's reputation for impartiality and fair dealings. Examples of such activities include the following:

   i. Owning a financial interest with an employee or representative of a contractor, customer, partner or competitor of Husky with whom you regularly come into contact while performing Husky business;

   ii. Accepting a personal discount (on products, services or other items) from an employee or representative of a contractor, customer, partner or competitor of Husky, which is not generally available in the normal course of business; and

   iii. Dealing directly in the course of normal Husky responsibilities with a related person who is employed by a contractor, customer, partner or competitor of Husky.

   iv. Proper Record-Keeping

6. Proper Record-Keeping

If you prepare any accounting, sales, or operations records, you are required to do so in a manner that ensures Husky's books, records and accounts reflect accurately, fairly, in reasonable detail, and on a timely basis, all transactions, acquisitions, dispositions of assets, and other business affairs of Husky.

You are prohibited from the following:

a. Establishing or maintaining any unrecorded funds, assets or transactions on behalf of Husky;

b. Making any false, artificial, or misleading entries in the books, records and documents of Husky for any reason;

c. Engaging in any arrangement internally and/or externally that results in such prohibited acts; and

d. Initiating any transaction or making any payment on behalf of Husky with the intention or understanding that the transaction or payment is other than what is described in its documentation.

7. Community Investment and Political Donations

Husky's Community Investment program supports the corporate business strategy by building Husky's reputation as a responsible and constructive member of the communities in which we operate and our Personnel live. The Company's Funding Guidelines are publicly available to promote understanding of Husky's focus areas and to assist potential applicants.

Husky observes and respects all laws concerning the making of political contributions in all applicable jurisdictions. The Company does not provide political donations in respect of municipal elections, leadership contests, individual candidates or riding/constituency associations. Husky will consider political donation requests from, and for the benefit of, registered major political parties at the provincial level in Canada where permitted.

Personnel who make individual political contributions shall not attempt to have such contributions expensed to Husky directly or indirectly and Husky will not reimburse any Personnel who submits an expense account for a political contribution.

In jurisdictions where it is allowed to make donations to political parties, the Company will only donate to political parties through participation in fundraising events, which in most cases will be fundraising dinners.

See Community Investment Policy 1.14 for further information.

8. Lobbying

You, as Personnel, should consult with your Senior Vice President or the Legal Department to ensure that lobbying is not prohibited in your jurisdiction before engaging in any lobbying activities.

Lobbying is not a prohibited activity in Canada, but Husky must make monthly public filings in Canada and several provinces in order to report lobbying activities that have taken place on behalf of the Company. Husky maintains a monthly internal reporting process in order to facilitate these filings, and you should report to your Vice President any lobbying activities you or your reports participate in either on behalf of Husky or as a member of an association in which you are a Husky representative (for example, CAPP).

You may be lobbying on behalf of Husky if you are communicating with a "public office holder".The term "public office holder" is very broad and includes MPs, MLAs, other elected officials, all public servants and most government agencies and boards appointed by governments.

If your unit is considering lobbying, or considering making a pre-arranged appointment with any federal public office holders, you should contact the Director, Government Relations for more guidance.

If you are communicating with a federal public office holder, you should report lobbying activities internally if your communication is about:

a. legislative proposals;

b. the introduction, passage, defeat or amendment of bills or resolutions;

c. the making or amending of regulations, policies or programs; or

d. the awarding of governmental grants, contributions, or other financial benefits.

Each province has slightly different rules defining what is and is not lobbying. Generally, if you are communicating with a provincial public office holder, you should report lobbying activities internally if you are communicating in an attempt to influence:

a. the development of any legislative proposal;

b. the introduction, passage, defeat or amendment of any bill or resolution;

c. the making or amendment of any regulation;

d. the development, amendment or termination of any policy or program;

e. a decision to sell all or part of the Crown's interest in a business, enterprise or institution that provides goods or services to the Crown or to the public;

f. a decision regarding privatization or outsourcing;

g. the awarding of any grant or financial benefit by or on behalf of the government; or

h. the awarding, amendment or termination of any contract, grant or financial benefit by or on behalf of the government or a provincial entity.

If you are requesting information from a federal or provincial public office holder, or communicating with them about the interpretation, application or enforcement of existing laws or regulations to Husky, you do not need to report it as lobbying. You also do not need to report lobbying activity if you are communicating with federal public office holders in a proceeding that is a matter of public record, such as submissions to the Senate or House of Commons.

If you have any doubt as to whether your interaction with a public office holder constitutes lobbying, you should include a brief summary of it in your monthly report to your Vice President so that it can be reviewed by the Legal Department. Jurisdictions outside Canada have different rules regarding lobbying activities. You must consult with the Legal Department or your Senior Vice President to ensure compliance with all applicable lobbying rules.

9. Company Resources

9.1 Safeguard Company Resources

You are expected to safeguard all Husky assets and information, including any personal or customer private information. You must not engage in any theft, pilferage, willful damage, or misuse of Husky property. Such conduct may be a crime and may be reported to appropriate law enforcement authorities.

9.2 Confidential Information and Intellectual Property

You are prohibited from disclosing, misappropriating, or using confidential information or intellectual property which is owned, developed, or otherwise possessed by Husky, except as specifically authorized, and only for the performance of your duties for Husky. Personal use of confidential information or intellectual property is prohibited.

Confidential information includes, but is not limited to, corporate records, contractor and customer lists, reports, papers, devices, processes, programs, plans, methods, other intellectual property, other non-public information, and any other information which is designated as confidential at the time it is made available to you or which, because of the circumstances under which you receive it, would reasonably be considered to be confidential. This applies to information owned or developed by Husky, or by third parties and in the possession of Husky. Confidential information also includes any earnings information, other financial information, or information about significant business transactions that has not been publicly disclosed by Husky. See Company Communications, Disclosure and Insider Trading/Reporting Policy 1.02 for further information.

Intellectual property includes computer software programs, technical processes, inventions, research devices, reports or articles containing any form of unique or original innovation or development, whether or not protected by patent, trademark, copyright, or otherwise.

Any intellectual property created or developed by you within your scope of employment is owned by Husky.

9.3 Use of E-mail, Voicemail, Computer and Other Technology

Husky assets are the property of Husky and are provided for the purpose of conducting work for the Company. Reasonable personal use may be permitted provided that it is otherwise in compliance with Husky's policies and the Company reserves the right to monitor, review and restrict personal use of our property at all times. You are responsible for exercising good judgment regarding the reasonableness of personal use and the amount and type of personal information you store. If any doubt exists, you should consult your supervisor or Department Manager.

All users of Husky assets shall:

a. Comply with all legal requirements;

b. In no way cause harm to Husky's public image;

c. Do nothing to adversely impact other users' use of, or access to, Husky assets; and

d. Comply with all Husky policies, procedures and guidelines.

Subject to applicable law, Husky may monitor, review, audit, intercept and access your communications using Husky's technology for any legitimate business reason or when required by law. You acknowledge that monitoring of your private communications and your use of Husky's technology may be necessary due to certain legitimate business reasons or when required by law.

See Information Security Policy 5.07 and Acceptable Use Policy 5.08 for further information.

9.4 Record Retention

Husky creates, receives and maintains records to carry out business activities and to document actions, transactions and decisions. Husky owns all of the information and records that are created, generated or received by Personnel and others performing business activities on behalf of Husky.

A record, regardless of format or media, contains information that has business value to the Company, provides evidence of legal, financial or operational activity and may contain business decisions, actions or policies. All records must be managed to ensure Husky retains information in accordance with our obligations, applicable policies and procedures and Husky's Records Retention Schedule, and to ensure records are available for business use. You are required to comply with all applicable legal obligations regarding the preservation of documents and information.

See Information Management Policy 5.04 for further information.

10. Fair Competition

Husky is committed to conducting business ethically and legally. A key component of this commitment is to comply with competition laws, the purpose of which is to preserve and promote a competitive market economy. Competition laws in Canada and other jurisdictions contain criminal offences including price-fixing and bid-rigging. Other conduct that may raise competition concerns includes refusal to supply, market restriction, tied selling, exclusive dealing, resale price maintenance, abuse of a dominant position, or non-criminal agreements between competitors. Accordingly, you are prohibited from:

a. Engaging in communications or entering into any agreement with Husky's actual or potential competitors, whether oral or written, direct or indirect, private or public, that might allow anyone to infer an agreement or understanding between actual or potential competitors about:

   i. price, sale or purchase terms (including, but not limited to, agreements on credit terms or discounts, or agreements to issue same or similar price lists or to stabilize prices or coordinate the timing of pricing changes);

   ii. production or supply (including, but not limited to, agreements to fix, maintain, control, prevent, lessen or eliminate the supply of a product); or

   iii. allocation of customers, territories, sales or product markets;

b. Entering into an agreement, whether oral or written, where Husky and one or more parties: agree that one or more of them will refrain from bidding, agree to bid at agreed prices, or agree to withdraw a bid (known as bid rigging);

c. Entering into any agreement, whether oral or written, where Husky and one or more competitors agree to refuse to sell to customers dealing with a separate competitor, or an agreement to hinder the separate competitor in some other manner;

d. Sharing confidential competitively sensitive information with actual or potential competitors. This includes information relating to: pricing, pricing policies, discounts, rebates or terms; supply and contractors; customers; marketing or business strategies; revenues or margins; costs; capacity and production levels; and other competitively sensitive information; and

e. Participating in discussions regarding competitively sensitive information at trade association or industry meetings, or in other settings, when actual or potential competitors are present. If such discussions occur at a meeting, you should loudly state that you do not wish to take part in such discussion, request that your departure be recorded in the minutes, if applicable, and leave the room or hang up the telephone, as applicable. You must also immediately report the discussions to your supervisor and the Legal Department.

The consequences of violating competition laws are serious and can include imprisonment and significant fines. Questions arising with respect to compliance with competition laws, including whether any proposed business strategies or plans may raise concerns with respect to competition laws, should be referred to your supervisor or to the Legal Department.

See Competition Act Compliance Policy 1.18 for further information.

11. Transactions and Relationships with Contractors

The Procurement Department or Commercial Department responsible for procurement and contract activities ("Procurement") provides corporate leadership for entering into external commitments with contractors. Upon receiving internal authorization, Procurement will enter into agreements, in accordance with the Code, that will maximize value to Husky, minimize risk and ensure security of supply.

Procurement sets the guidelines used to procure goods, equipment and contractor services in accordance with the Procurement Practices maintained by the Procurement function.

Procurement determines the procurement/contracting strategy in concert with the client group. Creating a competitive marketplace is a key component of Husky's procurement strategy. Competitive bidding is the preferred approach, but it is only one of a number of strategies that is used. Sole sourcing is only used where there is proper justification. You are prohibited from improperly disclosing outside Husky any information regarding bids, evaluations, negotiations or award of business in general which, in the opinion of Husky, could create an unfair advantage or disadvantage for an individual bidder or jeopardize the bid process or the intent of Husky's procurement process.

See Procurement Policy 1.05 for further information.

12. Bribery and Other Improper Payments

Husky strictly prohibits any bribes or any other corrupt payments made on Husky's behalf. No Personnel will authorize, pay, promise or offer to give anything of value to any individual or entity in order to improperly influence that individual or entity to act favorably towards Husky. Further, no Personnel will request or authorize any third party to make any such payment, promise or offer. Personnel are also strictly prohibited from soliciting or accepting bribes or any other corrupt payments, or acting as an intermediary for a third party in the solicitation, acceptance, payment or offer of a bribe. Such behavior is illegal and is unacceptable business conduct wherever Husky conducts business. Bribery can expose Husky and our Personnel to fines and other penalties, including imprisonment.

Husky prohibits any "off-the books" payments and any falsification or destruction of Husky books, records or accounts to cover up bribery or any corrupt payments. This prohibition applies regardless of amount and includes the falsification of books, records and accounts to conceal bribery of public officials, commercial bribery or any other corrupt payments.

Bona fide hospitality, promotional expenses and other business courtesies are not prohibited to the extent that they are reasonable, proportionate and permissible under all applicable laws, rules and regulations, including any ethical codes. Husky prohibits its Personnel from improperly providing business courtesies or anything of value to any individual, including public officials, in exchange for that individual taking some action that benefits Husky.

For purposes of these prohibitions, whether the recipient of any bribe or corrupt payment works in the public or private sector is irrelevant.

In some countries where Husky conducts business, it may be local practice for businesses to make payments of nominal value to lower-level government officials in order to expedite or facilitate routine, non-discretionary government actions. Husky, however, strictly prohibits facilitation payments, whether legal or not.

As well as complying with the provisions in the Code, you must exercise common sense and judgment in assessing whether any arrangement could be perceived to be corrupt or otherwise inappropriate. If you have any questions about any proposed action, the applicability of this section or questions regarding the propriety of specific business courtesies, you must consult the executive responsible for your business unit or the Senior Vice President, General Counsel & Secretary before proceeding.

See Anti-Bribery & Anti-Corruption Policy 1.24 for more information.

13. Accepting Hospitality and Other Business Courtesies

The acceptance of bona fide hospitality and other business courtesies are not prohibited by the Code to the extent that they are reasonable and proportionate. You may accept moderate hospitality as an accepted business courtesy provided:

- It is at a level and frequency which Husky, at our expense, could provide in return;
- It is consistent with generally accepted industry business practices; and
- It is permitted under applicable laws and regulations.

You cannot solicit or accept anything of value which might influence business decisions or compromise independent judgment.

Examples of things of value that are prohibited include, but are not limited to:

- Kickbacks or a quid pro quo;
- Cash or cash equivalents (e.g., gift cards);
- Gifts that are not modest in value, both in isolation and when considered in the context of other gifts and hospitality received;
- Excessive entertainment and hospitality, and any accommodation or transportation not directly associated with the execution of Husky business;
- Favours, including offers of employment or internships to you or a related person;
- Other favours such as engaging a company owned by you or a related person or paying inflated prices to purchase property or services;
- Donations to a charity or other cause of your choosing; and
- Loans, loan guarantees or other extensions of credit on preferential terms, or other intangible forms of preferential treatment.

You must exercise common sense and judgment in assessing whether any hospitality, other business courtesy or offering could be perceived to be inappropriate.

If you have any doubts about a proposed expense, the applicability of this section or any proposed action, you must consult the executive responsible for your business unit or the Senior Vice President, General Counsel & Secretary before proceeding.

14. Insider Trading, Securities Hedging, Loans

Husky has publicly traded securities and therefore must comply with certain legal and regulatory requirements regarding the public disclosure of material information, and our Personnel (as defined in the Company Communications, Disclosure and Insider Trading/ Reporting Policy 1.02) must comply with insider trading and reporting requirements.

You may become aware of non-public material information—that is, information that has not been made publicly available by Husky in either a press release or an annual or interim financial report that would reasonably be expected to have a significant effect on the market price or value of the Company's securities.

Personnel and their Related Parties (as defined in Policy 1.02) are prohibited from:

- purchasing or selling;
- exercising options to purchase or sell; or
- tipping someone else to purchase or sell or not to purchase or sell,

securities of Husky with knowledge of non-public material information relating to Husky (even if you acquired it as a "tip" from others). Trading or tipping while in possession of non-public material information is a serious violation of the law and can result in severe civil or criminal penalties, including imprisonment.

See Company Communications, Disclosure and Insider Trading/Reporting Policy 1.02 for further information. Policy 1.02 will continue to apply after termination of the relationship of Personnel (as defined in that Policy) with Husky to the extent that the individual is in possession of non-public material information at the time of termination. In such case, no transaction of securities of Husky may take place until the information becomes public or ceases to be material. You must also comply with all trading restrictions and blackout periods set forth in Policy 1.02.

If you are unsure whether information is non-public material information, consult the Legal Department before making any decision to buy or sell a security, or before disclosing the information.

15. External Communications

Husky designates specific people to speak on behalf of the Company to groups which include, but are not limited to, the investment community, investors, regulators and the media. The Code also extends to social media platforms, including Facebook, Twitter and YouTube.

See Company Communications, Disclosure and Insider Trading/Reporting Policy 1.02 for further information.

16. Privacy

Husky respects the privacy of individuals and endeavours to maintain the accuracy, confidentiality and security of personal information under its custody or control. The Company is committed to complying with applicable privacy laws, always taking care to protect the personal information of individuals. Privacy Policy 5.02 applies in respect of all activities of Husky that are governed by privacy legislation in Canada and the United States.

Sometimes the privacy legislation and/or an individual's right to privacy are different from one jurisdiction to another. Husky strongly recommends that Personnel and others using Husky business systems do not store personal information on Husky's business systems that is not required for business purposes. Personnel should not have any expectation of privacy with respect to their use of Husky-provided or issued equipment, devices or resources.

See Privacy Policy 5.02 for further information.

17. Economic Sanctions and Terrorism Financing

Husky complies with all applicable laws regarding economic sanctions and terrorism financing. Such laws encompass a wide variety of measures, including limitations on official and diplomatic contacts or travel, the imposition of legal measures to restrict or prohibit trade or other economic activity between certain countries or with certain persons, or the seizure or freezing of property. You are prohibited from causing Husky to be in violation of any of these laws.

18. Reporting Suspected Non-Compliance

If you become aware of any actual or suspected breach of or non-compliance with of the Code, you must report the incident in one of the following ways:

a. Discuss the matter with your supervisor, Department Manager or Human Resources Business Partner; or

b. Report the concern to the Ethics Help Line, which may be done anonymously, either over the phone or online by going to the secure EthicsPoint website at www.ethicspoint.com and selecting “File a Report” at the top of the screen; or

c. Contact any one of the Senior Vice President, Human & Corporate Resources, the Senior Vice President, General Counsel & Secretary, the CFO, the CEO, or the Chairman of the Audit Committee.

Husky strictly prohibits retaliatory action in any form against any Personnel who, in good faith, reports a possible breach or non-compliance with the Code. A report is not in good faith if you make the report, (1) knowing that it is false or misleading or knowing that there is not a sufficient indication of breach or non-compliance, or (2) solely to intentionally harm any person or entity associated with Husky. When a report is not made in good faith, you may be subject to disciplinary action, including summary termination for just cause in accordance with the prevailing laws and regulations of the applicable jurisdiction, or the immediate termination of a service contract. Disciplinary measures may be taken against Personnel if they participated in prohibited activity, even if they reported it.

After a report is made, all Personnel must cooperate fully and openly with any investigation into suspected breach or non-compliance of the Code. Failure to cooperate or to provide truthful information may lead to the individual being subject to disciplinary action, up to and including termination for just cause in accordance with the prevailing laws and regulations of the applicable jurisdiction, or the immediate termination of a service contract.