Husky Energy Inc.

Annual Information Form

For the Year Ended December 31, 2016

February 24, 2017

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ADVISORIES

In this 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 noted, all financial information included and incorporated by reference in this AIF is determined using IFRS as issued by the International Accounting Standards Board.

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

See also "Reader Advisories" at the end 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
m^3	cubic metres
GJ	gigajoule
long tons/day	imperial measurement of a metric tonne per calendar day
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	tons of carbon dioxide equivalent

Acronyms	
AER	Alberta Energy Regulator
AIF	Annual Information Form
AQMS	Air Quality Management System
ARO	Asset Retirement Obligations
ASC	Alberta Securities Commission
BACT	Best Available Control Technology
BLIERs	Base-Level Industrial Emissions Requirements
CAPP	Canadian Association of Petroleum Producers
CAAQS	Canadian Ambient Air Quality Standards
CFA	Canadian Fuels Association
CHOPS	Cold Heavy Oil Production with Sand
CKI	Cheung Kong Infrastructure Holdings Limited
CNOOC	China National Offshore Oil Corporation
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalent
COGEH	Canadian Oil and Gas Evaluation Handbook
COSIA	Canada's Oil Sands Innovation Alliance
CSA	Canadian Securities Administrators
ECON	Saskatchewan Ministry of the Economy
EDGAR	Electronic Data Gathering, Analysis, and Retrieval system
ELs	Exploration Licences
EOR	Enhanced Oil Recovery

EPA	U.S. Environmental Protection Agency
FASB	Financial Accounting Standards Board
FEED	Front End Engineering Design
FPSO	Floating Production, Storage and Offloading Vessel
GHG	Greenhouse Gases
GHGRP	Greenhouse Gas Reporting Program
GSA	Gas Sales Agreement
HMLP	Husky Midstream Limited Partnership
HOA	Heads of Agreement
HOIMS	Husky Operational Integrity Management System
HSB	Husky Synthetic Blend
H_2S	Hydrogen sulfide
IETA	International Emissions Trading Association
IFRS	International Financial Reporting Standards
IPIECA	International Petroleum Industry Environmental Conservation Association
LARP	Lower Athabasca Regional Plan
LFEs	Large Final Emitting Facilities
LMR	Liability Management Ratio
LNG	Liquefied Natural Gas
MBCA	Migratory Bird Convention Act
MD&A	Management's Discussion and Analysis
NGL	Natural Gas Liquids
NIT	NOVA Inventory Transfer
NOx	Nitrogen Oxide
OPEC	Organization of Petroleum Exporting Countries
PAH	Power Assets Holdings Limited
PSC	Production Sharing Contract
REC	Reduced Emissions Completions
RFS	Renewable fuel standard
RIN	Renewable Identification Numbers
RVO	Renewable volume obligation
SAGD	Steam Assisted Gravity Drainage
SDD	Significant Discovery Declaration
SEC	Securities and Exchange Commission of the United States
SEDAR	System for Electronic Document Analysis and Retrieval
SGS	Saskatchewan Gathering System
SO_2	Sulfur dioxide
TSX	Toronto Stock Exchange
U.S.	United States
WCS	Western Canada Select
WTI	West Texas Intermediate
2-D	two-dimensional
3-D	three-dimensional

The Company uses the terms 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 and does not represent value equivalency at the wellhead.

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.

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.

Coal bed methane
The primary energy source of natural gas is methane. Coal bed methane is methane found and recovered from the coal bed seams. The methane is normally trapped in coal by water that is under pressure. When the water is removed, the methane is released.

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 or Yukon 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/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 one are referred to as High-TAN crudes.

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

Liquefied petroleum gas
Liquefied propanes and butanes, separately or in mixtures.

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.

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, butane and condensate or a combination 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 environments aspects. An initial Plan of Development in a development area needs both SKK Migas and the Minister of Energy and Mineral Resources approval. Subsequent Plans of Development in the same development area only need SKK Migas approval.

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.

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.

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.

Sulphur
An element that occurs in natural gas and petroleum.

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.

U.S. Shelf Prospectus
The U.S. universal short form prospectus filed by the Company on December 22, 2015 with the Alberta Securities Commission ("ASC") and filed as part of a U.S. registration statement on Form F-10 with the U.S. Securities and Exchange Commission ("SEC").

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
A vertical section of seismic data consisting of numerous adjacent traces acquired sequentially along a straight line.

3-D seismic survey
Three-dimensional seismic imaging which uses a grid of numerous cables rather than a few lines stretched in one line.

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,		
(Cdn $ per U.S. $)	**2016**	**2015**	**2014**
Year-end	1.343	1.384	1.160
Low	1.254	1.173	1.059
High	1.459	1.399	1.167
Average	1.325	1.279	1.104

Note: The year-end exchange rates were as quoted by the Bank of Canada for the noon buying rate as at the last day of the relevant period. The high, low and average rates were either quoted or calculated within each of the relevant periods.

CORPORATE STRUCTURE

Husky Energy Inc.

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 has its registered office and its head and principal office 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 place of incorporation, continuance or organization, as the case may be, as at December 31, 2016.[1] All of the following companies and partnerships, except as otherwise indicated, are 100 percent beneficially owned or controlled or directed, directly or indirectly, by Husky.

Name	Jurisdiction
Subsidiary of Husky Energy Inc.	
Husky Oil Operations Limited	Alberta
Subsidiaries and jointly controlled entities of Husky Oil Operations Limited	
Husky Oil Limited Partnership	Alberta
Husky Terra Nova Partnership	Alberta
Husky Downstream General Partnership	Alberta
Husky Energy Marketing Partnership	Alberta
Husky Energy International Corporation	Alberta
Sunrise Oil Sands Partnership (50 percent)	Alberta
BP-Husky Refining LLC (50 percent)	Delaware
Lima Refining Company	Delaware
Husky Marketing and Supply Company	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.

2014

On March 17, 2014, the Company issued U.S. $750 million of 4.00 percent notes due April 15, 2024 pursuant to a shelf prospectus and U.S. registration statement. 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. The notes are unsecured and unsubordinated and rank equally with all of the Company's other unsecured and unsubordinated indebtedness.

On June 15, 2014, the Company repaid its maturing 5.90 percent notes. The amount paid to noteholders was U.S. $772 million, including U.S. $22 million of interest, equivalent to $839 million in Canadian dollars at the time of repayment, including interest of $25 million.

On June 19, 2014, the Company's $1.6 billion revolving syndicated credit facility was increased to $1.63 billion. The maturity, previously set to expire on August 31, 2014, was extended to June 19, 2018. The Company also increased the limit on one of its operating facilities from $50 million to $100 million.

On September 15, 2014, the Company launched a commercial paper program in Canada. The program 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.

On December 9, 2014, the Company issued 10 million Series 3 Preferred Shares at a price of $25.00 per share for aggregate gross proceeds of $250 million under a shelf prospectus. Holders of 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 declared by the Board of Directors. See "Dividends - Dividend Policy and Restrictions - Series 3 Preferred Share Dividends".

During 2014, the Company sanctioned three new heavy oil thermal developments in Saskatchewan: 10,000 bbls/day at Edam East, 3,500 bbls/day at Edam West and 10,000 bbls/day at Vawn, and construction work continued at the 10,000 bbls/day Rush Lake heavy oil thermal development.

At the Sunrise Energy Project, steaming commenced in December 2014.

In the Atlantic Region, development drilling had commenced at the South White Rose extension. The Company continued drilling at the North Amethyst Hibernia formation which targeted a secondary deeper zone below the main North Amethyst producing field. In addition, the Company and its partner commenced an 18 month appraisal and exploration drilling program in the Flemish Pass offshore Newfoundland and Labrador, including the area around the Bay Du Nord discovery. Hearings for the public review of the application for a wellhead platform to facilitate full field development at West White Rose were held during 2014. Construction continued on the dry-dock in Argentia, Newfoundland and early site preparation was advanced, including construction of a graving dock.

Development continued at the Ansell liquids rich gas resource play, in west central Alberta, with 31 wells (gross) drilled and 23 wells (gross) completed.

At the Liwan Gas Project, first gas from the deep water wells at the Liwan 3-1 gas field was achieved on March 30, 2014 with gas sales to the Guangdong market natural gas grid commencing on April 24, 2014. In addition, the tie-in of the Liuhua 34-2 field single production well into the Liwan 3-1 field deep water infrastructure was completed and commissioned with first gas production taking place in December 2014. Total conventional natural gas and natural gas liquids ("NGL") production averaged approximately 114.2 mmcf/day and 4.2 mbbls/day, respectively.

Progress continued on the shallow water gas developments in the Madura Strait Block during 2014. Work related to the BD field engineering, procurement, installation and construction contract continued. The contract for the construction and lease of a Floating Production, Storage and Offloading Vessel ("FPSO") received final approval in the second quarter of 2014 and was signed in December 2014. The Plan of Development for the MDK field to tie into the MDA-MBH combined development was approved by SKK Migas in July 2014.

The Company signed a Production Sharing Contract ("PSC") for the Anugerah contract area. Under the PSC, Husky has an obligation to carry out seismic surveys to assess the petroleum potential of the exploration block within the first three years.

2015

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

On March 6, 2015, the limit on the Company's $1.6 billion revolving syndicated credit facility previously set to expire on December 14, 2016, was increased to $2.0 billion, and the limit on the $1.63 billion revolving syndicated credit facility set to expire on June 19, 2018 was increased to $2.0 billion. The terms of the revolving syndicated credit facilities remained unchanged.

On March 12, 2015, the Company repaid the maturing 3.75 percent medium-term notes issued under a trust indenture dated December 21, 2009. The amount paid to noteholders was $306 million, including $6 million of interest.

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 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 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 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 December 22, 2015, the Company filed the U.S. Shelf Prospectus, which enables the Company to offer up to U.S. $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 January 22, 2018.

A stock dividend was introduced in the third quarter as an interim measure in lieu of 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.

Construction continued at the two 10,000 bbls/day thermal developments Edam East and Vawn. Construction also continued at the 4,500 bbls/day Edam West heavy oil thermal development, where capacity increased from 3,500 bbls/day to 4,500 bbls/day in 2015 reflecting design and efficiency improvements.

Construction was completed at the Rush Lake thermal development with first oil achieved in July 2015. Production commenced ahead of schedule with production from the development reaching a year end exit rate of 13,900 bbls/day, exceeding its design capacity which was revised in 2015 from 10,000 bbls/day to 12,000 bbls/day.

The Company sanctioned Rush Lake 2, a 10,000 bbls/day heavy oil thermal development.

The Sunrise Energy Project achieved first oil on Phase 1 in March 2015. Production from the Sunrise Energy Project continued to ramp-up.

Development activity at the White Rose core field and its satellites, including North Amethyst and the West and South White Rose Extensions, continued to advance. An exploration and appraisal drilling program continued at the Bay du Nord discovery in the Flemish Pass Basin in 2015, including ongoing drilling of the Bay d'Espoir exploration well.

The Company drilled and completed two production wells at the South White Rose Extension with peak production from the wells of 15,000 bbls/day (net Husky share) reached in early September. The Company secured the Henry Goodrich drilling rig for a two-year drilling program which will focus on development drilling at the White Rose field and satellite extensions.

Development continued at the Ansell liquids rich gas resource play, with 25 horizontal wells (gross) drilled and 28 horizontal wells (gross) completed.

At the Liwan Gas Project, the Company's entitlement share of production from the Liwan Gas Project was reduced from approximately 76 percent in late May 2015 to its equity interest of 49 percent, reflecting the completion of exploration cost recoveries from the Liwan 3-1 field, which were originally funded solely by the Company.

The Company sanctioned the development of the MDA, MBH and MDK gas fields having secured the Gas Sales Agreement ("GSA") for the first tranche of gas from the MDA-MBH fields development. The Company signed a PSC for an exploration block offshore China. The Company is the operator of the block during the exploration phase with a working interest of 100 percent. The Company also acquired 2-D and 3-D seismic survey data on the Anugerah contract area. Results from the seismic surveys' data continue to be evaluated to determine the potential for future drilling opportunities.

The Company signed a PSC for the 15/33 contract area in the South China Sea. Under the PSC, Husky has an obligation to drill two exploration wells within the first three years.

The Company and Imperial Oil entered into a contractual agreement to create a single expanded truck transport network of approximately 160 sites.

At the Lima Refinery, the Company proceeded with the initial stages of a crude oil flexibility project designed to improve reliability at the facility and allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada. The crude oil flexibility project is designed to allow the Refinery to swing between light and heavy crude oil feedstock.

At the BP-Husky Toledo Refinery, a feedstock optimization project was sanctioned by the joint arrangement partners that was designed to improve the Refinery’s ability to process high content naphthenic acids ("High-TAN") crude. The Refinery began processing bitumen from the Sunrise Energy Project in the second half of 2015.

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.

In March 2016, 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 November 15, 2016, the Company repaid its 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.

First oil was achieved at the 10,000 bbls/day Edam East heavy oil thermal development on April 18, 2016. Production from the development averaged 14,900 bbls/day in December 2016, exceeding its design capacity.

First oil was achieved at the 10,000 bbls/day Vawn heavy oil thermal development on June 16, 2016. Production from the development averaged 11,400 bbls/day in December 2016, exceeding its design capacity.

First oil was achieved at the 4,500 bbls/day Edam West heavy oil thermal development on August 29, 2016. Production from the development averaged 4,200 bbls/day in December 2016.

First oil was achieved from the Colony formation, at the Tucker Thermal Project in the Cold Lake region of Alberta, on April 19, 2016. Total production from the Tucker Thermal Project averaged 21,700 bbls/day in December 2016.

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. Production from the Sunrise Energy Project is expected to continue to ramp up with average annual production in 2017 expected to be in the range of 40,000 to 44,000 bbls/day (20,000 to 22,000 bbls/day net Husky share).

The Henry Goodrich rig resumed operations at North Amethyst. First production was achieved from the North Amethyst Hibernia formation well on September 15, 2016. An additional well was brought into production at the South White Rose drill center on November 29, 2016. The rig has since drilled an infill well at North Amethyst.

Engineering design and subsurface evaluation work continues at West White Rose to increase capital efficiency and improve resource capture.

The exploration and appraisal drilling program at the Bay du Nord discovery in the Flemish Pass Basin was completed during 2016. Since the program commenced in the fourth quarter of 2014, the Company has participated in three appraisal and four exploration wells in and around Bay du Nord, leading to two new oil discoveries at Bay de Verde and Baccalieu and two unsuccessful wells at Bay d`Espoir and Bay du Loup. 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 and its partner continue to assess the commercial potential of these discoveries.

In November 2016, the Canada-Newfoundland and Labrador Petroleum Board 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.

Production continued at the Ansell liquids rich gas resource play, with production averaging 34,500 boe/day. Limited development activity was undertaken in 2016.

On May 25, 2016, the Company completed the sale of Western Canada royalty interests to a third party for gross proceeds of $165 million, resulting in a pre-tax gain of $163 million and an after-tax gain of $119 million.

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.

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 its full design specification.

During the third quarter of 2016, the Company's China subsidiary 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 thousand cubic feet (mcf) at current exchange rates. Gross take-or-pay volumes from the fields remain unchanged in the range of 300-330 million cubic feet per day (mmcf/day). Liquids production, net to Husky, is 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.

At the Madura Strait, the shallow water gas developments continued to progress. At the liquids-rich BD field, development well drilling, completion and testing of all four wells has been completed. The facilities construction project is approximately 97 percent complete including the installation and testing of the shallow water platform, the subsea pipeline to shore and the onshore gas metering station. The FPSO vessel construction has been completed and the vessel is now moored at the field location in preparation for in-situ testing and commissioning. The project is on target for first production in the 2017 timeframe and is scheduled to ramp up to its full gas sales rate by the second half of 2017.

The Company has secured a gas sales agreement for the MDA and MBH fields, which will be developed in tandem. Negotiations of additional gas sales agreements for the MDA, MBH and MDK gas fields are in progress. A re-tendering process for a floating production vessel has been completed and the winning bidder was approved by SKK Migas. The vessel lease contract is being finalized and is planned to be signed in early 2017. Tendering is also underway for related engineering, procurement, construction and installation contracts. Production from the MDA, MBH and MDK fields is expected in the 2018 - 2019 timeframe.

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 Cheung Kong Infrastructure Holdings Limited ("CKI") owns 16.25 percent. The transaction enabled the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets. Proceeds from the transaction were received in the third quarter of 2016.

The Company and Imperial Oil received regulatory approval from the Canadian Competition Bureau during the second quarter of 2016 to create a single expanded truck transport network. The contract closing conditions were met late in the fourth quarter 2016 and the consolidation of the two networks is expected in the second half of 2017. This agreement will create an expanded fuel network across Canada to better serve Husky’s commercial trucking customers while Imperial will be providing fuel and marketing support. Under the agreement, Imperial Oil will convert its commercial sites to a branded wholesaler model. Husky will convert its commercial cardlocks, co-located Travel Centres and a select number of retail service stations to the Esso brand. Husky will assume management of all dealer relationships in the combined network, as well as ongoing network growth as an Esso-branded wholesaler. The expanded network will have 160 sites, effectively doubling the size of Husky’s existing cardlock network.

The Company has started pre front-end engineering and design ("FEED") work on a potential 30,000 bbls/day expansion of its asphalt processing capacity in Lloydminster. This business continues to show strong returns through the cycle, and its expansion would provide an additional outlet for the Company's growing heavy oil thermal production.

At the Lima Refinery, the Company continued to work on a crude oil flexibility project designed to improve reliability at the facility and allow for the processing of up to 40,000 bbls/day of heavy crude oil feedstock from Western Canada. The full scope of the project is expected to be completed in 2018.

The Company and its partner completed a feedstock optimization project at the BP-Husky Toledo Refinery in mid-July 2016. The Refinery is now able to process approximately 65,000 bbls/day of High-TAN crude oil to support production from the Sunrise Energy Project. The Refinery's overall nameplate capacity remains unchanged at 160,000 bbls/day.

DESCRIPTION OF HUSKY'S BUSINESS

General

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 includes exploration for, and development and production of, crude oil, bitumen, natural gas and NGLs (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, offshore East Coast of Canada (Atlantic Region) and offshore China and offshore Indonesia (Asia Pacific Region).

Downstream includes upgrading of heavy crude oil feedstock into synthetic crude oil in Canada (Upgrading), refining in Canada of crude oil, marketing of refined petroleum products including gasoline, diesel, ethanol blended fuels, asphalt and ancillary products, and production of ethanol (Canadian Refined Products) and refining in the U.S. of primarily crude oil to produce and market 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 therefore are grouped together as the Downstream business segment due to the similar nature of their products and services.

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 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 to the submissions 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 to promote transparent, honest and ethical behaviour in all of its business dealings. The Company has a Code of Business Conduct policy 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 of 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 are 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 all applicable laws, and 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 that is free of harassment and violence and where respectful treatment is the norm. The Husky Diversity and Respectful Workplace Policy applies to all employees and contractors.

As a responsible and constructive member of the communities in which it operates, Husky has a Community Investment Program that supports charitable organizations in many communities. 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 the pursuit of 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 conducts business. The policy includes Husky's Aboriginal Education Awards Program which assists Aboriginal people in achieving greater career success by encouraging them to pursue an advanced education.

Husky values continued education and professional development and provides employees with opportunities for development and continuing advancement of their skills, knowledge and experience. The Learning and Development policy sets out guidelines, eligibility and support for Husky employees.

Husky is committed to the security and protection of personnel, physical assets, property and information from criminal, hostile or malicious acts, consistent with the Husky 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 his/her 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 our operations, the Husky 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 through 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.

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 to issues that do not compromise the needs of future generations. In 2008, Husky implemented the Husky Operational Integrity Management System ("HOIMS"), which is followed by all Husky businesses. 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 implementation and 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 all 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 and demonstrate designated tasks and responsibilities effectively, efficiently and safely.
7. Report and investigate all 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 all relevant government regulations. Work constructively to influence proposed laws and regulations, and debate on emerging issues.
12. Design, construct, commission, operate and decommission all 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.

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. International Petroleum Industry Environmental Conservation Association ("IPIECA") produces guidelines that Husky uses to improve its environmental practices, enhance its strategic planning, engage with regulators and enhance operations. Husky is also a member of the International Emissions Trading Association ("IETA") whose objective is to build international policy and market frameworks for reducing greenhouse gases ("GHG") at 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 Facility, 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 3,500 well sites and facilities. In 2016, Husky spent approximately $87 million on Asset Retirement Obligations ("ARO"), and the Company expects to spend approximately $123 million in 2017 on environmental site closure activities, including abandonment, decommissioning, reclamation and remediation in North America. In the Asia Pacific Region, 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 asset retirement obligations. As at December 31, 2016, Husky has deposited funds of $156 million into the restricted cash accounts, of which $84 million relates to the Wenchang field and has been classified as current.

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 2016 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 "legacy" (inactive facility) sites ranging from former refineries to retail locations. Management and remediation plans are prepared for these sites based on current and future land use.

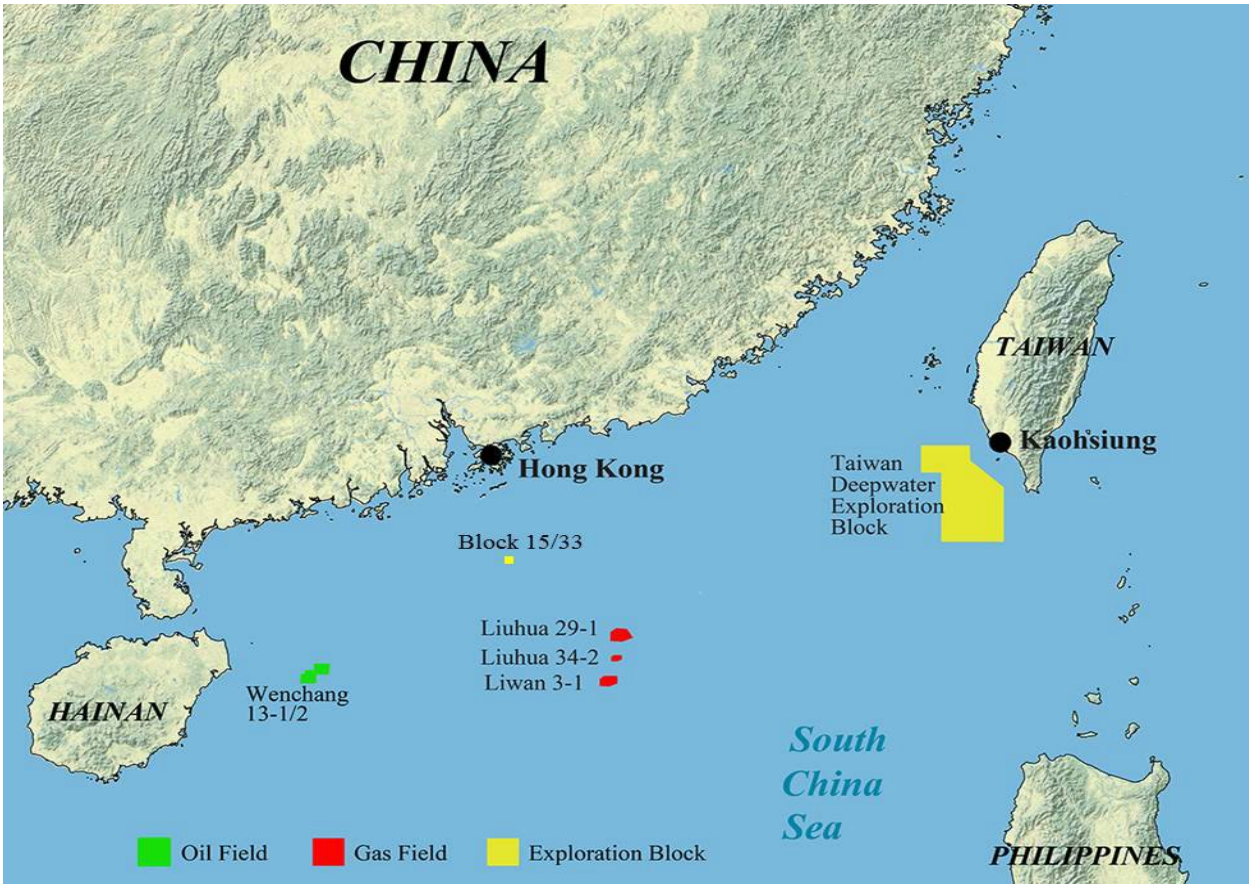
As part of the Company's review of proposed regulations that may affect its business and operations, the Company may, from time to time, prepare an internal analysis of the possible or expected impact of new regulations, which are subject to various uncertainties. It is not possible to predict with certainty the amount of additional investment in new or existing facilities required to be incurred 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.

Upstream Operations

Description of Major Properties and Facilities

Husky's portfolio of Upstream assets includes properties with reserves of light crude oil, medium crude oil, heavy crude oil, bitumen, NGL, natural gas and sulphur.

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 interest. The project was separated into deep water and shallow water development projects, with the Company acting as deep water operator and CNOOC acting as shallow water operator. The deep water 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, ten 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 to the central platform and on through to the onshore Gaolan Gas Plant. The single production well in the Liuhua 34-2 field was tied into the deep water facilities of the Liwan 3-1 field and commenced production in December 2014.

Gas sales from Liwan 3-1 and Liuhua 34-2 averaged 189 mmcf/day and 35 mmcf/day (gross), respectively, in 2016. In 2016, the Company's share of production from the two fields was 113 mmcf/day of conventional natural gas and 5.9 mbbls/day of NGL. Negotiations for the sale of the gas from the Liuhua 29-1 field are being pursued. Also in 2016, the Company completed the construction and tie-in of a second deepwater production pipeline to the shallow water central platform that will provide redundancy and production capacity for the future.

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 holds a 40 percent working interest in two oil fields, which commenced production in July 2002. The Wenchang 13-1 and 13-2 oil fields are currently producing from 32 wells in 100 metres of water into an FPSO stationed between fixed platforms located in each of the two fields. The Company’s share of production averaged 6.6 mbbls/day and 0.2 mbbls/day of light crude oil and NGL, respectively, during 2016. In 2016, the PSC was extended for 130 days corresponding to the duration of production suspension for FPSO maintenance experienced in 2014. The PSC is now due to expire in November 2017, after which the Company will no longer have a working interest in this field.

Block 15/33

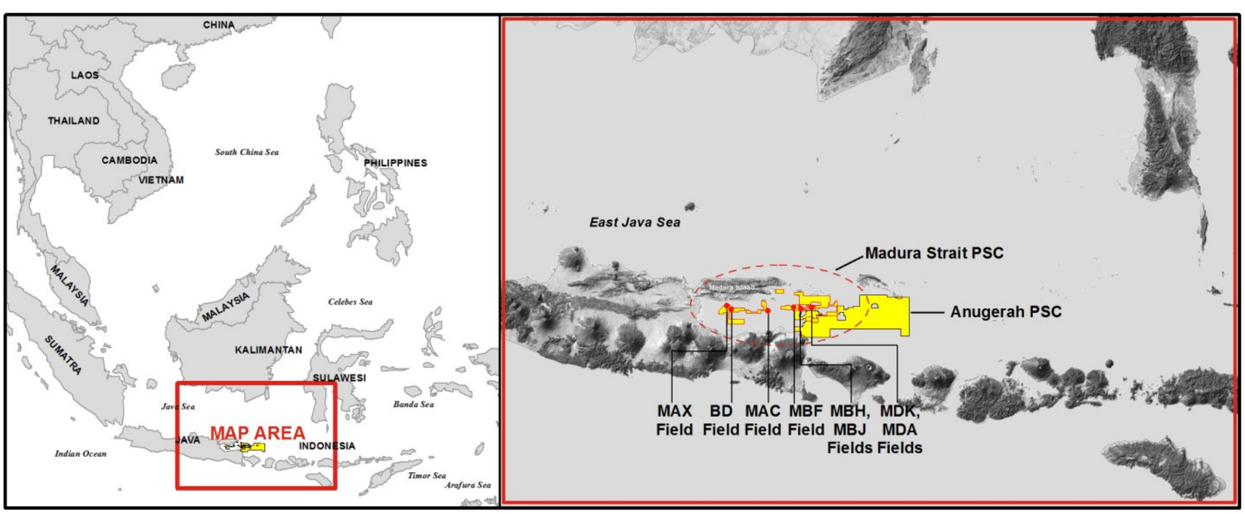
The Company executed a PSC in December 2015 for an exploration block offshore China. The 15/33 block is located in the Pearl River Mouth Basin in the South China Sea, about 140 kilometres southeast of the Hong Kong Special Administrative Region and covers an area of 155 square kilometres in water depths 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 cost recovery from production is to be allocated to the Company. The Company expects to drill two exploration wells in the 2017/2018 timeframe.

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.

Analysis of the 2-D seismic survey data acquired in 2014 has been completed and a number of significant prospects have been identified. The Company plans to acquire 3-D seismic survey data on the most attractive prospects during 2017.

Indonesia



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Madura Strait

The Company has a 40 percent interest in approximately 622,000 acres (2,516 square kilometres) of the Madura Strait Block, located offshore East Java, south of Madura Island, 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.

In October 2010, the Government of Indonesia approved an extension of the PSC that was originally awarded in 1982. The approval provided a 20-year extension to the contract, which now runs until 2032. The BD field Front End Engineering Design ("FEED") was completed in the second quarter of 2010.

In 2011, CNOOC drilled an appraisal well that confirmed commercial quantities of hydrocarbons in the MDA field. An exploration well was also drilled in 2011 on the MBH field, and a new gas field was discovered. The gas sales contracts for the BD field previously signed in 2010 with three gas buyers were amended in 2011. In November 2012, the functions of BP Migas, the Indonesian oil and gas regulator at the time, were temporarily transferred to the Energy and Mineral Resources Ministry and subsequently, a new body, SKK Migas, was established as the new industry regulator. As discussed and agreed with the new regulator, a re-tender for the BD field FPSO was made.

In 2012, the exploration drilling program resulted in discoveries on the MAC, MAX, MDK and MBJ fields.

In January 2013, the Plan of Development for a combined MDA and MBH development project was approved by SKK Migas. In July 2013, the BD field engineering, procurement, installation and commissioning contract was awarded and engineering/construction work under the contract commenced. The Government of Indonesia appointed a lead distributor for the major portion of the gas from the MDA and MBH fields and a HOA was signed. Exploration drilling on the block in 2013 resulted in an additional discovery at the MBF field.

In 2014, the tender plans for the combined development project for the MDA-MBH fields were approved by SKK Migas. The Plan of Development for the MDK field to tie into the MDA-MBH combined development was approved by SKK Migas in July 2014. A contract for the lease of an FPSO for the BD field was signed in December 2014.

In 2015, engineering and construction work continued at the liquids-rich BD field where the platform jacket and topsides were successfully set in approximately 55 metres of water in October 2015 and development drilling commenced in November 2015.

In November 2015, the Company sanctioned the development of the MDA, MBH and MDK gas fields and the GSA for the first tranche of gas from the MDA-MBH development was signed. In December 2015, the Minister of Energy and Mineral Resources appointed the buyers for the remaining available tranches of gas sales from the three fields and negotiation of the GSAs commenced in 2016. Also in November 2015, SKK Migas approved the plan of development for the MAC gas field which was discovered in 2012.

Progress continued on the shallow water gas developments during 2016. At the liquids-rich BD field, development well drilling, completion and testing of all four wells was completed. The facilities construction project is approximately 97 percent complete including the installation and testing of the shallow water platform, the subsea pipeline to shore and the onshore gas metering station. The FPSO vessel construction was completed and the vessel is now moored at the field location in preparation for in-situ testing and commissioning. The project is on target for first production in the 2017 timeframe and is scheduled to ramp up to its full gas sales rate by the second half of 2017.

The Company has secured a GSA for the MDA and MBH fields, which are expected to be developed in tandem. Negotiations of additional GSAs for the MDA, MBH and MDK gas fields are in progress. A re-tendering process for a floating production vessel has been completed, and the winning bidder was approved by SKK Migas. The lease contract for the vessel is being finalized and is expected to be signed in early 2017. Tendering is also underway for related engineering, procurement, construction and installation contracts. Production from the MDA, MBH and MDK fields is expected in the 2018 - 2019 timeframe. Combined net 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 NGLs once production is fully ramped up.

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 Block. 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 results are being evaluated to determine potential for future drilling opportunities.

Atlantic Region

The Company's offshore East Coast exploration and development program is focused in the Jeanne d'Arc Basin on the Grand Banks, which contains the Hibernia and Terra Nova fields, the White Rose field and satellite extensions, including North Amethyst, West White Rose and South White Rose, and the Flemish Pass Basin. In the Flemish Pass, 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 Newfoundland.

White Rose Oil Field

The White Rose oil field is located 354 kilometres off the coast of Newfoundland and Labrador and approximately 48 kilometres east of the Hibernia oil 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.

First oil was achieved at White Rose in November 2005. The White Rose field was the third oil field developed offshore Newfoundland and currently has 10 production wells, 10 water injection wells and three gas storage wells. During 2016, the Company's light crude oil production from the White Rose field was 16.9 mbbls/day (net Husky share).

On May 31, 2010, first oil was achieved from North Amethyst, the first satellite extension to 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. During 2016, the Company's light crude oil production from North Amethyst was 4.9 mbbls/day (net Husky share). In September 2016, the Company began production from the deeper Hibernia formation at North Amethyst utilizing existing infrastructure. As of December 31, 2016, the field had six production wells and four water injection wells.

Initial production from West White Rose was achieved in September 2011 through a two-well pilot project. These wells have helped provide further information on the reservoir to refine development plans for the full West White Rose field. During 2016, the Company's share of light crude oil production from this satellite field was 3.2 mbbls/day (net Husky share).

The Company continues to assess potential development options for the West White Rose satellite extension. One of the two concepts being assessed, a fixed wellhead platform, received government and regulatory approvals in 2015. A subsea option to develop the field is also being evaluated.

Production commenced from the South White Rose Extension in 2015 and development drilling continues. Production wells will be 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, 2016, the project had two production wells and one gas injection well. During 2016, the Company's share of light crude oil production from the South White Rose Extension was 3.8 mbbls/day (net Husky share).

Terra Nova Oil Field

The Terra Nova field is located approximately 350 kilometres southeast of St. John's, Newfoundland. 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, 2016, there were 14 development wells drilled in the Graben area, consisting of eight production wells, three water injection wells and three 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.

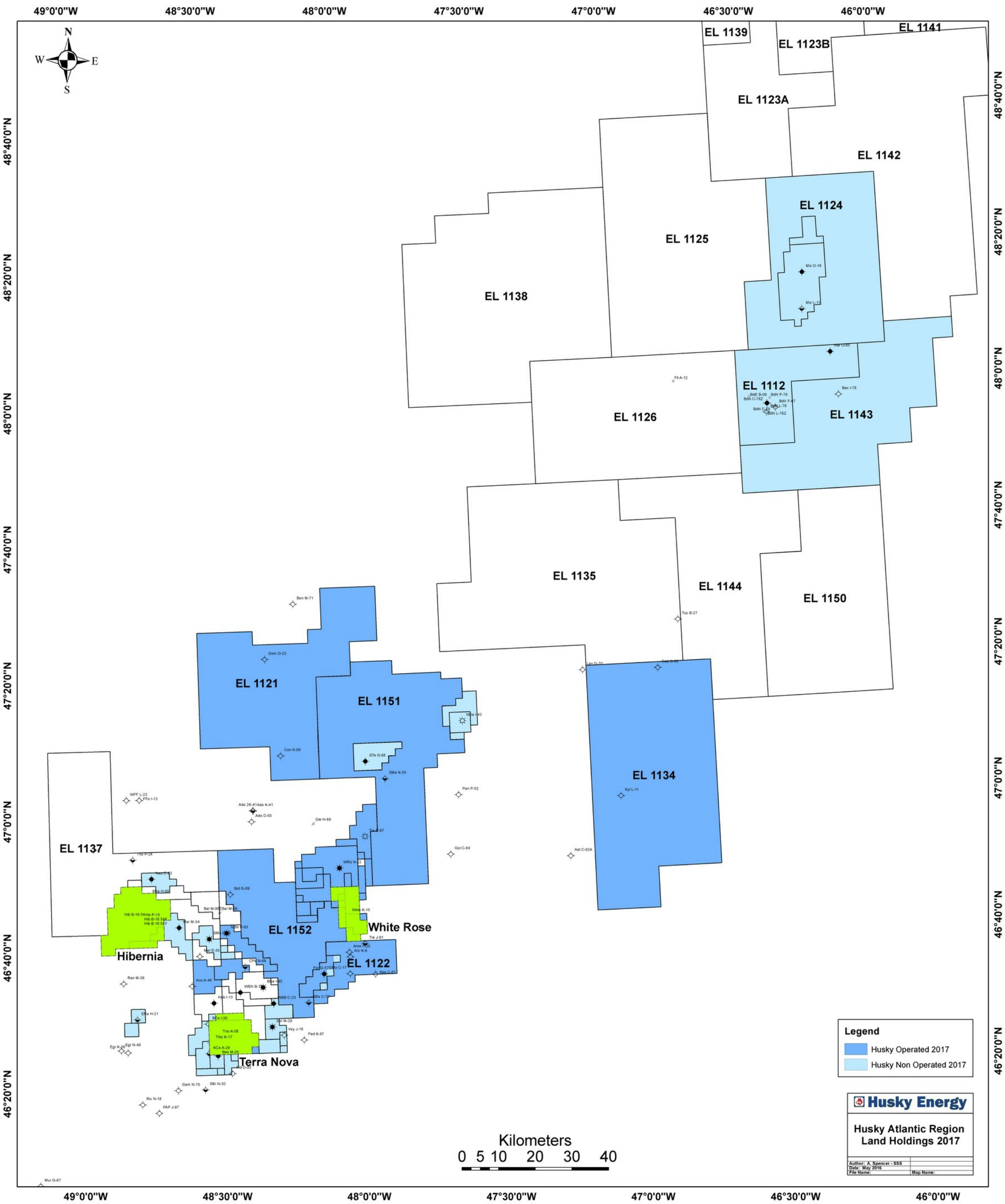
Light crude oil production during 2016 from the Terra Nova field was 4.3 mbbls/day (net Husky share).

East Coast Exploration

The Company presently holds working interests ranging from 5.8 percent to 73.125 percent in 23 significant discovery areas in the Jeanne d'Arc Basin and Flemish Pass Basin, offshore Newfoundland and Labrador and Baffin Island.

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 wells were drilled as part of an 18 month long appraisal drilling program in which the Company participated in three appraisal and four exploration wells. 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 and its partner continue to assess the commercial potential of these discoveries.

In November 2016, the Canada-Newfoundland and Labrador Petroleum Board 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 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 Company operated ELs in the Jeanne d'Arc Basin.



Greenland

The Company has decided not to elect to enter sub-Period 2 for either of its two ELs offshore West Greenland, and consequently, these licences expired in 2016.

Heavy Oil

The majority of the Company's heavy oil assets are located in the Lloydminster 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 Lloydminster. The Company operates over 4,500 wells in the area, with a 100 percent working interest in the majority of these wells. 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 Lloydminster Asphalt Refinery, the Husky Lloydminster Upgrader and third-party pipeline systems at Hardisty, Alberta, providing full integration with the Company's Upstream Infrastructure and Marketing and Downstream businesses.

Production of heavy crude oil and bitumen from the Lloydminster area uses a variety of technologies including Steam Assisted Gravity Drainage ("SAGD") or Thermal production, Cold Heavy Oil Production with Sand ("CHOPS"), Horizontal Wells, Waterflooded fields and Non-Thermal Enhanced Oil Recovery ("EOR"). The Company is pursuing a significant expansion of its Heavy Oil Thermal production while actively managing the natural decline in its CHOPS production. The Company also produces natural gas from numerous small shallow pools in the Lloydminster region and recovers solution gas produced from heavy crude oil wells.

Lloydminster Thermal Developments

Lloydminster Thermal production consists of nine Thermal plants located in the Lloydminster region of Saskatchewan: Bolney, Edam East, Edam West, Paradise Hill, Pikes Peak, Pikes Peak South, Rush Lake, Sandall, and Vawn. Each plant has numerous production pads and utilizes SAGD technology.

During 2016, construction was completed at the Edam East, Vawn and Edam West heavy oil thermal developments; heavy crude oil production averaged 14,900 bbls/day, 11,400 bbls/day and 4,200 bbls/day, respectively, in December 2016.

In 2016, the Company sanctioned three new Lloyd thermal projects with total design capacity of about 30,000 bbls/day at Dee Valley, Spruce Lake North and Spruce Lake Central. Subject to regulatory approval, first production for all three thermal projects is expected in 2020.

In 2017, work will continue on the 10,000 bbls/day Rush Lake 2 thermal development, with first oil expected in the first half of 2019.

Tucker Lake Oil Sands Thermal Development

Tucker Lake is an in-situ SAGD oil sands project located 30 kilometres northwest of Cold Lake, Alberta that commenced Bitumen production at the end of 2006.

In December 2016, Tucker Lake Thermal Project bitumen production averaged 21,700 bbls/day, with production estimated to reach 30,000 bbls/day by 2019 with further development and optimization.

Non-Thermal Oil Production

The Company operates approximately 3,500 CHOPS heavy oil vertical wells, 550 horizontal heavy oil wells and 300 waterflooded medium crude oil wells located in the Lloydminster areas in Alberta and Saskatchewan.

Non-Thermal Enhanced Oil Recovery

The Company operated five carbon dioxide ("CO_2") injection EOR pilot projects in 2016 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.

McMullen Willow Creek Thermal Development

The Company will commence oil sands evaluation drilling of 19 wells at McMullen Willow Creek in the first quarter of 2017 and progress towards an Alberta Energy Regulator ("AER") application in the second quarter of 2017. First oil for the 10,000 bbls/day Phase I Plant based on the development plan is 2024 with a conceptual plan to progress up to nine additional plants by 2040.

Oil Sands

Sunrise Energy Project

On March 31, 2008, Husky and BP completed a transaction that created an integrated North American oil sands business. The business is 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 an in-situ SAGD oil sands project located in the Athabasca region of northern Alberta. The project will be developed in multiple phases with Phase 1 consisting of two 30,000 bbls/day of bitumen plants (Plants 1A and 1B). The project was sanctioned in 2010 after which the Company awarded major engineering and construction contracts for the central processing and field facilities. During 2010, the partnership reached an agreement on the movement of diluted bitumen to market and transportation of diluent to the Sunrise oil sands site. Development drilling of all planned SAGD horizontal well pairs for Phase 1 were completed in 2012. Construction of the Central Processing Facilities and field facilities were substantially completed in 2014. Steaming from Plant 1A commenced in late 2014, and first oil was achieved in the first quarter of 2015. At the end of December 2016, there were 55 producing well pairs. In 2016, bitumen production averaged approximately 25,600 bbls/day (12,800 bbls/day net Husky share). The production ramp-up will continue through the coming year and production is expected to increase to an annual average of approximately 40,000 - 44,000 bbls/day (20,000 - 22,000 bbls/day net Husky share) in 2017.

Western Canada (excluding Heavy Oil and Oil Sands)

Foothills Operations

Foothills operations are located primarily in Western Alberta. Primary areas of operations consist of Rocky Mountain House, Edson and Grande Prairie. This newly formed operations area is centered on a gas resource growth strategy.

Within Foothills operations, the Company operates 300 facilities, including the Ram River Gas Plant in which the Company has an average 85 percent working interest. Production in 2016 consisted of approximately 2.1 mbbls/day of light and medium crude oil, 6.4 mbbls/day of NGL and 270.2 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 area. The Kakwa Wilrich liquids rich gas resource play south of Grande Prairie is a non-operated asset in which the Company has a 50 percent working interest. During 2016, production averaged 3.2 mboe/d, respectively (net Husky share) with one new horizontal well (gross) drilled.

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 in the Cardium zone. During 2016, production for the play averaged 1.7 mboe/day. No development was carried out in 2016.

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 92 percent working interest in approximately 150 net sections of contiguous lands. The Company has been actively developing the Spirit River Wilrich and Notikewin formations using multi-stage fractured horizontal wells since 2012. Production from the Ansell/Galloway area has doubled since 2012 and in 2016 averaged 2.2 mbbls/day of NGL and 107.4 mmcf/day of conventional natural gas. The Company operates over 370 producing wells (gross) at Ansell including 40 Spirit River horizontal wells (gross) and 20 Cardium horizontal wells (gross).

The Company's activity in this area decreased in 2016 due to low natural gas prices. The Company drilled two horizontal wells (gross) and completed four horizontal wells (gross) during 2016. At year end, one rig was drilling in the area with a second scheduled to start up in early 2017.

Plans in 2017 for Foothills include a 16 well development program targeting the Spirit River formation.

Plains Operations

The Company's Western Canada Plains operations are located in Central Alberta, Northern Alberta and Southwest Saskatchewan. As at December 31, 2016, the Company operates 30 crude oil and 20 natural gas facilities with approximately 4,000 active wells throughout the area. Production in 2016 from these operations averaged 21.9 mbbls/day of crude oil, 0.9 mbbls/day of NGL and 83.8 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 2016 from the Rainbow Lake Development averaged 6.6 mbbls/day of light crude oil, 0.7 mbbls/day of NGL and 70.7 mmcf/day of natural gas.

In 2016, the Company progressed modifications to its Rainbow Lake processing plant that are expected to enable sales of 4.0 mbbls/day of NGL by 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. These were consolidated as one EL in 2015 and cover 483,000 gross acres (466,000 net acres) in the Northwest Territories. 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 kilometer 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 ("SDD") on 545 sections (150,000 hectares) of land north of the Gambill Fault on EL 494 as part of the Conoco Phillips Dodo Canyon E-76 SDD application. Additionally, five sections of land were granted Significant Discovery License status earlier in 2016 based on the MGM East MacKay I-78 well on a thin strip of land south of the Gambill Fault. No activity is planned in 2017.

Distribution of Oil and Gas Production

Crude Oil and NGL

The Company provides heavy crude oil feedstock to its Upgrader and its Asphalt Refinery, which are located in Lloydminster, Alberta/Saskatchewan. The Upgrader and Asphalt Refinery process the majority of the Company's heavy crude oil production from the Lloydminster area. The Company also purchases third-party volumes. The Company markets heavy crude oil production directly to refiners located in the mid-west and eastern U.S. and Canada in addition to the BP-Husky Toledo Refinery. The Company markets its light and synthetic crude oil production to third-party refiners in Canada, the U.S. and Asia in addition to the Company's Lima Refinery. NGLs are sold to petrochemical end users, retail and wholesale distributors and refiners in North America.

The Company markets third-party volumes of crude oil, synthetic crude oil and NGLs in addition to its own production. For a discussion of the Company's distribution methods associated with crude oil and NGLs, see "Commodity Marketing".

Natural Gas

The following table shows the distribution of the Company's North American gross average daily natural gas production for the years indicated. The Company markets third-party natural gas production in addition to its own production. In North America, natural gas is sold to end users and retail and wholesale distributors.

	Years Ended December 31,		
	2016	**2015**	**2014**
		(mmcf/day)	
Sales Distribution			
United States	164	218	183
Canada	79	113	138
	243	331	321
Sales to Aggregators	8	—	—
Internal Use (1)	191	183	186
	442	514	507

(1) The Company consumes natural gas for fuel at several of its facilities.

Disclosures of Oil and Gas Activities

Production History

Average Gross Daily Production[(1)]	Year Ended Dec. 31, 2016	Three Months Ended Dec. 31, 2016	Sept. 30, 2016	Jun 30, 2016	Mar. 31, 2016
Canada - Western Canada					
Light and Medium Crude Oil (mbbls/day)	23.4	15.1	16.5	29.6	33.0
Heavy Crude Oil (mbbls/day)	54.1	48.4	49.5	57.5	61.5
Bitumen (mbbls/day)[(2)]	97.4	115.3	103.6	88.0	81.8
Conventional Natural Gas (mmcf/day)	442.4	406.0	414.2	441.5	508.7
NGL (mbbls/day)	8.0	7.3	7.9	8.0	8.8
Canada - Atlantic Region					
Light and Medium Crude Oil (mbbls/day)	33.1	34.3	24.8	32.7	40.5
China - Asia Pacific Region[(3)]					
Light and Medium Crude Oil (mbbls/day)	6.6	5.5	6.3	7.1	7.4
Conventional Natural Gas (mmcf/day)	113.5	149.4	107.1	87.3	109.9
NGL (mbbls/day)	6.0	8.6	5.5	4.8	5.2
Total Gross Production (mboe/day)	**321.2**	**327.0**	**301.0**	**315.8**	**341.3**

Average Gross Daily Production	Year Ended Dec. 31, 2015	Three Months Ended Dec. 31, 2015	Sept. 30, 2015	Jun 30, 2015	Mar. 31, 2015
Canada - Western Canada					
Light and Medium Crude Oil (mbbls/day)	36.4	34.4	35.0	37.3	38.8
Heavy Crude Oil (mbbls/day)	69.1	66.7	67.9	70.0	71.9
Bitumen (mbbls/day)[(2)]	63.1	79.0	66.7	50.3	55.7
Conventional Natural Gas (mmcf/day)	513.9	507.9	505.0	518.8	524.2
NGL (mbbls/day)	8.8	8.6	8.4	8.7	9.7
Canada - Atlantic Region					
Light and Medium Crude Oil (mbbls/day)	36.8	43.5	29.6	32.6	41.7
China - Asia Pacific Region[(3)]					
Light and Medium Crude Oil (mbbls/day)	7.3	6.4	7.5	7.4	8.0
Conventional Natural Gas (mmcf/day)	175.1	152.8	152.7	202.8	192.8
NGL (mbbls/day)	9.4	8.3	8.3	10.3	10.7
Total Gross Production (mboe/day)	**345.7**	**357.0**	**333.0**	**336.9**	**356.0**

Average Gross Daily Production	Year Ended Dec. 31, 2014	Three Months Ended Dec. 31, 2014	Sept. 30, 2014	Jun 30, 2014	Mar. 31, 2014
Canada - Western Canada					
Light and Medium Crude Oil (mbbls/day)	41.8	40.7	41.4	40.5	44.9
Heavy Crude Oil (mbbls/day)	76.8	77.5	76.1	78.1	75.5
Bitumen (mbbls/day)[(2)]	54.6	55.7	56.2	54.6	52.0
Conventional Natural Gas (mmcf/day)	506.8	521.3	509.3	490.6	505.9
NGL (mbbls/day)	9.8	10.2	9.1	9.6	10.2
Canada - Atlantic Region					
Light and Medium Crude Oil (mbbls/day)	44.6	43.4	37.3	47.6	50.3
China - Asia Pacific Region[(3)]					
Light and Medium Crude Oil (mbbls/day)	4.8	7.4	2.7	0.3	8.6
Conventional Natural Gas (mmcf/day)	114.2	180.2	161.0	113.0	—
NGL (mbbls/day)	4.2	7.8	6.6	2.3	0.1
Total Gross Production (mboe/day)	**340.1**	**359.6**	**341.1**	**333.6**	**325.9**

(1) Total production volumes for 2016, for each product type, are set forth in the Reconciliation of Gross Proved Plus Probable Reserves table.

(2) Bitumen includes production from heavy oil thermal developments and the Tucker thermal development located near Cold Lake, Alberta. Bitumen production includes heavy oil thermal average daily gross production of 65.4 mbbls/day, 48.4 mbbls/day and 43.8 mbbls/day for the years ended December 31, 2016, 2015 and 2014, respectively.

(3) Reported production volumes include the Company's entitlement share of production from the Liwan Gas Project which was approximately 76 percent until late May 2015 and then reduced to its equity interest of 49 percent, reflecting the completion of exploration cost recoveries from the Liwan 3-1 field which were originally funded solely by the Company.

Operating Netback Analysis[1][2]

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

	Year Ended	Three Months Ended			
Average Per Unit Amounts	**Dec 31, 2016**	**Dec 31, 2016**	**Sept 30, 2016**	**June 30, 2016**	**Mar 31, 2016**
Company Total[3]					
Sales volume (mboe/day)	321.2	327.0	301.0	315.8	341.3
Gross Revenue ($/boe)[4]	$33.08	$39.90	$33.11	$34.59	$25.02
Royalties ($/boe)	$2.60	$3.46	$2.01	$3.12	$1.74
Production and Operating Costs ($/boe)[4]	$14.04	$13.92	$15.15	$13.90	$13.31
Transportation Costs ($/boe)[5]	$0.25	$0.20	$0.25	$0.27	$0.29
Operating netback ($/boe)	$16.19	$22.32	$15.70	$17.30	$9.68
Light and Medium Crude Oil ($/bbl)[3]					
Canada - Western Canada					
Gross Revenue[4]	$40.95	$50.88	$46.01	$48.86	$26.72
Royalties	$3.85	$5.06	$3.48	$3.68	$3.63
Production and Operating Costs[4]	$26.92	$34.42	$28.86	$24.21	$24.91
Operating netback	$10.18	$11.40	$13.67	$20.97	($1.82)
Canada - Atlantic Canada					
Gross Revenue	$60.01	$69.19	$61.05	$61.83	$50.00
Royalties	$8.70	$11.92	$7.14	$10.44	$5.51
Production and Operating Costs	$18.48	$14.85	$28.07	$20.27	$14.20
Transportation Costs[5]	$2.46	$1.93	$3.01	$2.57	$2.47
Operating netback	$30.37	$40.49	$22.83	$28.55	$27.82
Canada - Total					
Gross Revenue[4]	$50.66	$62.28	$53.24	$54.32	$38.19
Royalties	$6.69	$9.84	$5.67	$7.23	$4.67
Production and Operating Costs[4]	$21.98	$20.80	$28.39	$22.14	$19.01
Operating netback	$21.99	$31.64	$19.18	$24.95	$14.51
China					
Gross Revenue	$54.98	$68.65	$54.35	$60.34	$40.62
Royalties	$3.68	$4.68	$3.75	$4.17	$2.48
Production and Operating Costs	$11.68	$14.19	$10.27	$14.27	$8.52
Operating netback	$39.62	$49.78	$40.33	$41.90	$29.62
Total					
Gross Revenue[4]	$51.11	$62.91	$53.34	$54.90	$38.41
Royalties	$6.38	$9.30	$5.41	$6.92	$4.46
Production and Operating Costs[4]	$20.91	$20.14	$25.98	$21.34	$18.06
Operating netback	$23.82	$33.47	$21.95	$26.64	$15.89
Heavy Crude Oil ($/bbl)					
Canada - Western Canada					
Gross Revenue[4]	$30.50	$36.30	$35.04	$34.88	$18.12
Royalties	$2.67	$3.55	$3.06	$2.89	$1.42
Production and Operating Costs[4]	$18.58	$21.90	$20.47	$16.09	$16.35
Operating netback	$9.25	$10.85	$11.51	$15.90	$0.35
Bitumen ($/bbl)					
Canada - Western Canada					
Gross Revenue[4][5]	$27.63	$33.80	$29.53	$30.95	$12.83
Royalties	$1.49	$2.04	$0.85	$2.41	$0.53
Production and Operating Costs[4]	$10.94	$12.30	$11.69	$9.00	$10.44
Operating netback	$15.20	$19.46	$16.99	$19.54	$1.86

Average Per Unit Amounts	Year Ended Dec 31, 2016	Three Months Ended Dec 31, 2016	Sept 30, 2016	June 30, 2016	Mar 31, 2016
Conventional Natural Gas ($/mcf)[3]					
Canada - Western Canada					
Gross Revenue[4][6]	$2.06	$2.92	$2.24	$1.24	$1.92
Royalties[6][7]	($0.04)	$0.04	($0.06)	$0.02	($0.11)
Production and Operating Costs[4]	$1.93	$1.76	$2.02	$2.10	$1.83
Operating netback	$0.17	$1.12	$0.28	($0.88)	$0.20
China					
Gross Revenue	$13.58	$13.10	$10.86	$14.81	$15.96
Royalties	$0.72	$0.68	$0.57	$0.78	$0.82
Production and Operating Costs	$1.17	$0.87	$1.20	$1.38	$1.39
Operating netback	$11.69	$11.55	$9.09	$12.65	$13.75
Total					
Gross Revenue[4]	$4.40	$5.65	$3.99	$3.46	$4.41
Royalties	$0.12	$0.22	$0.08	$0.10	$0.07
Production and Operating Costs[4]	$1.77	$1.52	$1.85	$1.99	$1.75
Operating netback	$2.51	$3.91	$2.06	$1.37	$2.59
Natural Gas Liquids ($/bbl)[3]					
Canada - Western Canada					
Gross Revenue[4]	$31.14	$38.78	$29.18	$31.09	$26.59
Royalties	$7.59	$10.01	$7.22	$7.77	$5.77
Production and Operating Costs[4]	$11.39	$10.29	$11.92	$12.56	$10.84
Operating netback	$12.16	$18.48	$10.04	$10.76	$9.98
China					
Gross Revenue	$47.14	$53.04	$44.83	$45.94	$40.92
Royalties	$2.65	$3.00	$2.57	$2.59	$2.25
Production and Operating Costs	$7.14	$5.38	$7.31	$8.44	$8.34
Operating netback	$37.35	$44.66	$34.95	$34.91	$30.33
Total					
Gross Revenue[4]	$38.01	$46.47	$35.62	$36.68	$31.89
Royalties	$5.45	$6.22	$5.29	$5.77	$4.46
Production and Operating Costs[4]	$9.57	$7.64	$10.03	$11.01	$9.92
Operating netback	$22.99	$32.61	$20.30	$19.90	$17.51

(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) During 2016, Husky completed the sale of 65% of its ownership interest in select midstream assets. These assets are held by HMLP, in which Husky has a 35% investment. The investment is considered a joint venture and is prospectively being accounted for using the equity method.

(3) Includes associated co-products converted to boe and mcf.

(4) Transportation expenses for Western Canada production has been deducted from both prices received (i.e., gross revenue) and production and operating costs to reflect the actual price received at the oil and gas lease.

(5) Includes offshore transportation costs shown separately from gross revenue. During the first quarter of 2016, the Company reclassified Oil Sands transportation costs to net against gross revenue. Prior periods have not been restated.

(6) Includes sulphur sales revenues/royalties.

(7) Alberta Gas Cost Allowance reported exclusively as gas royalties.

	Year Ended	Three Months Ended			
Average Per Unit Amounts	**Dec 31, 2015**	**Dec 31, 2015**	**Sept 30, 2015**	**June 30, 2015**	**Mar 31, 2015**
Company Total(2)					
Sales volume (mboe/day)	345.7	357.0	333.0	336.9	356.0
Gross Revenue ($/boe)(3)	$41.06	$34.89	$39.45	$49.50	$40.84
Royalties ($/boe)	$3.43	$2.60	$2.70	$4.37	$4.04
Production and Operating Costs ($/boe)(3)	$15.14	$14.51	$15.52	$15.72	$14.87
Transportation Costs ($/boe)(4)	$0.49	$0.50	$0.51	$0.48	$0.48
Operating netback ($/boe)	$22.00	$17.28	$20.72	$28.93	$21.45
Light and Medium Crude Oil ($/bbl)(2)					
Canada - Western Canada					
Gross Revenue(3)	$48.49	$42.60	$45.33	$61.55	$42.98
Royalties	$5.30	$4.86	$4.74	$5.90	$5.61
Production and Operating Costs(3)	$26.92	$27.96	$25.04	$27.04	$27.58
Operating netback	$16.27	$9.78	$15.55	$28.61	$9.79
Canada - Atlantic Canada					
Gross Revenue	$65.89	$54.12	$64.98	$79.25	$68.55
Royalties	$7.43	$5.26	$4.39	$10.55	$9.48
Production and Operating Costs	$16.76	$15.31	$20.94	$19.20	$13.36
Transportation Costs(4)	$2.58	$2.19	$3.14	$2.69	$2.50
Operating netback	$39.12	$31.36	$36.51	$46.81	$43.21
Canada - Total					
Gross Revenue(3)	$55.94	$47.81	$52.87	$68.55	$54.92
Royalties	$6.37	$5.08	$4.57	$8.07	$7.61
Production and Operating Costs(3)	$21.81	$20.90	$23.17	$23.39	$20.22
Operating netback	$27.76	$21.83	$25.13	$37.09	$27.09
China(5)					
Gross Revenue	$60.80	$52.69	$53.54	$71.75	$64.00
Royalties	$3.12	$3.78	$0.73	$4.10	$3.40
Production and Operating Costs	$11.71	$13.53	$11.64	$9.67	$12.13
Operating netback	$45.97	$35.38	$41.17	$57.98	$48.47
Total					
Gross Revenue(3)	$56.37	$48.18	$52.94	$68.85	$55.73
Royalties	$6.07	$4.99	$4.17	$7.69	$7.23
Production and Operating Costs(3)	$20.90	$20.34	$21.97	$22.12	$19.49
Operating netback	$29.40	$22.85	$26.80	$39.04	$29.01
Heavy Crude Oil ($/bbl)					
Canada - Western Canada					
Gross Revenue(3)	$37.16	$28.71	$36.51	$50.21	$32.97
Royalties	$4.44	$2.62	$4.02	$6.11	$4.93
Production and Operating Costs(3)	$18.16	$18.30	$18.09	$17.57	$18.88
Operating netback	$14.56	$7.79	$14.40	$26.53	$9.16
Bitumen ($/bbl)					
Canada - Western Canada					
Gross Revenue(3)(4)	$34.47	$25.67	$33.86	$48.45	$34.97
Royalties	$2.92	$1.39	$3.30	$4.33	$3.40
Production and Operating Costs(3)	$14.94	$12.14	$15.19	$18.75	$15.16
Transportation Costs(4)	$1.20	$1.08	$1.14	$1.46	$1.22
Operating netback	$15.41	$11.06	$14.23	$23.91	$15.19

	Year Ended	Three Months Ended			
Average Per Unit Amounts	**Dec 31, 2015**	**Dec 31, 2015**	**Sept 30, 2015**	**June 30, 2015**	**Mar 31, 2015**
Conventional Natural Gas ($/mcf)[2]					
Canada - Western Canada					
Gross Revenue[3][6]	$2.67	$2.43	$2.77	$2.76	$2.81
Royalties[6][7]	($0.08)	($0.03)	($0.23)	($0.04)	—
Production and Operating Costs[3]	$2.08	$2.01	$2.10	$2.05	$2.13
Operating netback	$0.67	$0.45	$0.90	$0.75	$0.68
China[5]					
Gross Revenue	$14.98	$15.76	$15.51	$14.50	$14.43
Royalties	$0.81	$0.96	$0.81	$0.75	$0.76
Production and Operating Costs	$0.77	$0.81	$0.90	$0.92	$0.51
Operating netback	$13.40	$13.99	$13.80	$12.83	$13.16
Total					
Gross Revenue[3]	$5.80	$5.51	$5.76	$6.09	$5.96
Royalties	$0.13	$0.18	$0.04	$0.19	$0.21
Production and Operating Costs[3]	$1.74	$1.72	$1.82	$1.75	$1.69
Operating netback	$3.93	$3.61	$3.90	$4.15	$4.06
Natural Gas Liquids ($/bbl)[2]					
Canada - Western Canada					
Gross Revenue[3]	$34.08	$32.46	$32.53	$38.84	$32.66
Royalties	$7.75	$7.55	$8.41	$7.96	$7.18
Production and Operating Costs[3]	$12.26	$11.99	$12.25	$12.26	$12.55
Operating netback	$14.07	$12.92	$11.87	$18.62	$12.93
China[5]					
Gross Revenue	$56.99	$52.91	$53.92	$62.65	$56.71
Royalties	$3.19	$2.99	$2.75	$3.46	$3.16
Production and Operating Costs	$4.78	$5.09	$5.36	$5.58	$3.24
Operating netback	$49.02	$44.83	$45.81	$53.61	$50.31
Total					
Gross Revenue[3]	$45.88	$42.46	$43.18	$51.97	$45.29
Royalties	$5.39	$5.31	$5.74	$5.51	$5.07
Production and Operating Costs[3]	$8.39	$8.60	$8.82	$8.58	$7.66
Operating netback	$32.10	$28.55	$28.62	$37.88	$32.56

(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 for Western Canada production has been deducted from both prices received (i.e., 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 gross revenue. During the first quarter of 2016, the Company reclassified Oil Sands transportation costs to net against gross revenue. Prior periods have not been restated.

(5) Reported production volumes include the Company's entitlement share of production from the Liwan Gas Project which was approximately 76 percent until late May 2015 and then reduced to its equity interest of 49 percent, reflecting the completion of exploration cost recoveries from the Liwan 3-1 field which were originally funded solely by the Company.

(6) Includes sulphur sales revenues/royalties.

(7) Alberta Gas Cost Allowance reported exclusively as gas royalties.

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

Producing Wells

	Oil Wells		Natural Gas Wells		Total	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Canada						
Alberta	2,513	2,161	4,138	2,917	6,651	5,078
Saskatchewan	3,031	2,933	226	224	3,257	3,157
British Columbia	3	1	273	250	276	251
Newfoundland	33	14	—	—	33	14
	5,580	5,109	4,637	3,391	10,217	8,500
International						
China	32	13	10	5	42	18
Libya	—	—	—	—	—	—
	32	13	10	5	42	18
As at December 31, 2016	**5,612**	**5,122**	**4,647**	**3,396**	**10,259**	**8,518**
Canada						
Alberta	3,929	3,157	5,220	3,774	9,149	6,931
Saskatchewan	5,380	4,535	1,262	1,139	6,642	5,674
British Columbia	195	57	297	263	492	320
Newfoundland	31	12	—	—	31	12
	9,535	7,761	6,779	5,176	16,314	12,937
International						
China	32	13	10	5	42	18
Libya	3	1	—	—	3	1
	35	14	10	5	45	19
As at December 31, 2015	**9,570**	**7,775**	**6,789**	**5,181**	**16,359**	**12,956**
Canada						
Alberta	4,208	3,444	5,312	3,846	9,520	7,290
Saskatchewan	6,273	5,356	1,345	1,220	7,618	6,576
British Columbia	199	57	296	260	495	317
Newfoundland	30	11	—	—	30	11
	10,710	8,868	6,953	5,326	17,663	14,194
International						
China	28	11	10	5	38	16
Libya	3	1	—	—	3	1
	31	12	10	5	41	17
As at December 31, 2014	**10,741**	**8,880**	**6,963**	**5,331**	**17,704**	**14,211**

Non-Producing Wells

	2016					
	Oil Wells		**Natural Gas Wells**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Alberta	3,106	2,895	1,630	1,339	4,736	4,234
Saskatchewan	4,247	4,081	216	193	4,463	4,274
British Columbia	—	—	59	40	59	40
Total	7,353	6,976	1,905	1,572	9,258	8,548

(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, 2016.

(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, 2016, the Company had a royalty interest in 1,221 wells, of which 652 were oil producers and 569 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 2016, there were 1,129 gross and 1,036 net oil wells and 191 gross and 149 net natural gas wells that were completed in two or more formations and from which production is not commingled.

Landholdings - Developed Acreage

(thousands of acres)	Gross	Net
As at December 31, 2016		
Western Canada		
Alberta	3,201	2,624
Saskatchewan	502	455
British Columbia	145	122
Manitoba	—	—
	3,848	3,201
Atlantic Region	54	20
	3,902	3,221
China	17	7
Libya	7	2
Total	**3,926**	**3,230**
As at December 31, 2015		
Western Canada		
Alberta	4,552	2,904
Saskatchewan	814	647
British Columbia	184	144
Manitoba	2	—
	5,552	3,695
Atlantic Region	54	20
	5,606	3,715
China	17	7
Libya	7	2
Total	**5,630**	**3,724**
As at December 31, 2014		
Western Canada		
Alberta	4,574	2,924
Saskatchewan	806	638
British Columbia	185	145
Manitoba	3	—
	5,568	3,707
Atlantic Region	57	20
	5,625	3,727
China	17	7
Libya	7	2
Total	**5,649**	**3,736**

Landholdings - Undeveloped Acreage

(thousands of acres)	Gross	Net
As at December 31, 2016		
Western Canada		
Alberta	3,190	2,733
Saskatchewan	670	629
British Columbia	575	463
Manitoba	—	—
	4,435	3,825
Northwest Territories and Arctic	483	466
Atlantic Region	2,354	1,191
	7,272	5,482
United States	—	—
China	95	46
Indonesia	3,589	3,216
Greenland	—	—
Taiwan	1,904	1,428
Total	**12,860**	**10,172**
As at December 31, 2015		
Western Canada		
Alberta	4,231	2,978
Saskatchewan	1,467	1,329
British Columbia	644	506
Manitoba	2	1
	6,344	4,814
Northwest Territories and Arctic	483	466
Atlantic Region	2,675	1,278
	9,502	6,558
United States	2	—
China	72	35
Indonesia	3,589	3,216
Greenland	5,205	4,555
Taiwan	1,904	1,428
Total	**20,274**	**15,792**
As at December 31, 2014		
Western Canada		
Alberta	4,529	3,247
Saskatchewan	1,708	1,550
British Columbia	743	583
Manitoba	3	1
	6,983	5,381
Northwest Territories and Arctic	483	466
Atlantic Region	2,698	1,295
	10,164	7,142
United States	89	29
China	56	27
Indonesia	1,559	1,186
Greenland	5,205	4,555
Taiwan	2,545	1,909
Total	**19,618**	**14,848**

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

The Company has commitments totaling approximately $90 million related to exploration to be completed in the Atlantic region between 2021 and 2025. In addition, the Company has approximately $48 million of commitments related to exploration in the North West 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.

Approximately 324,784 acres, or less than six percent of the Company's net undeveloped landholdings in Canada, will be subject to expiry in 2017.

The Company holds interests in a diverse portfolio of undeveloped petroleum assets in Western Canada, the Atlantic Region, China, Taiwan and Indonesia, the Canadian 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, 2016.

Drilling Activity - Number of Wells Drilled

	Year Ended December 31,					
	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Canada - Western Canada						
Exploration						
Oil	15	15	5	4	53	44
Gas	—	—	4	1	9	6
Dry	—	—	1	1	3	3
	15	15	10	6	65	53
Development						
Oil	60	60	121	105	469	403
Gas	3	2	34	24	78	67
Dry	—	—	—	—	3	3
	63	62	155	129	550	473
	78	77	165	135	615	527
Canada - Atlantic Region						
Development						
Oil	2.0	1.4	2.0	1.4	1.0	0.1
China						
Development						
Oil	—	—	1.0	0.4	—	—
Gas	—	—	—	—	—	—
	—	—	1.0	0.4	—	—
Indonesia						
Development						
Oil	—	—	—	—	—	—
Gas	4.0	1.6	—	—	—	—
	4.0	1.6	—	—	—	—

Stratigraphic Test Wells

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Canada - Western Canada	—	—	—	—	6	6
Canada - Atlantic Region	3.0	1.0	5.0	1.8	2.0	1.0
China	—	—	—	—	—	—
Indonesia	—	—	—	—	1.0	0.4

Service Wells

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Canada - Western Canada	31	31	38	35	121	121
Canada - Atlantic Region	—	—	—	—	2.0	0.9
China	—	—	—	—	—	—
Indonesia	—	—	—	—	—	—

Costs Incurred

	Total	Western Canada	Atlantic Region	Total Canada	United States	China	Indonesia	Libya
				($ millions)				
Property acquisition								
Unproven	—	—	—	—	—	—	—	—
Proven	7	7	—	7	—	—	—	—
Exploration	63	25	34	59	—	4	—	—
Development	1,190	683	262	945	—	106	139	—
2016	**1,260**	**715**	**296**	**1,011**	**—**	**110**	**139**	**—**

	Total	Western Canada	Atlantic Region	Total Canada	United States	China	Indonesia	Libya
				($ millions)				
Property acquisition								
Unproven	—	—	—	—	—	—	—	—
Proven	56	56	—	56	—	—	—	—
Exploration	249	38	208	246	—	(1)	4	—
Development	1,932	1,525	342	1,867	—	31	34	—
2015	**2,237**	**1,619**	**550**	**2,169**	**—**	**30**	**38**	**—**

	Total	Western Canada	Atlantic Region	Total Canada	United States	China	Indonesia	Libya
				($ millions)				
Property acquisition								
Unproven	—	—	—	—	—	—	—	—
Proven	51	51	—	51	—	—	—	—
Exploration	375	260	98	358	—	12	5	—
Development	3,940	2,785	752	3,537	—	380	23	—
2014	**4,366**	**3,096**	**850**	**3,946**	**—**	**392**	**28**	**—**

Oil and Gas Reserves Disclosures

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 February 24, 2017 has been prepared in accordance with NI 51-101 effective December 31, 2016. The reserves information prepared in accordance with the rules of the U.S. Financial Accounting Standards Board ("FASB") and the U.S. Securities Exchange Commission ("SEC") ("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, 2016.

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, 2017 and an effective date of December 31, 2016 and are Husky’s total proved and probable reserves. Gross reserves or gross production are reserves or production attributable to Husky's 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 effect of hedging gains and losses. Unless otherwise indicated, all financial information is in accordance with International Financial Reporting Standards ("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 contain oil that is lighter and less viscous than typical bitumen.

Disclosure of Exemption Under National Instrument 51-101

Husky sought and was granted by the Canadian Securities Administrators ("CSA") an exemption from the requirement under NI 51-101 to involve independent qualified oil and gas reserves evaluators or auditors. Notwithstanding this exemption, the Company involves independent qualified reserves auditors as part of Husky's corporate governance practices. Their involvement helps assure 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, is superior to that 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 auditor also reviews and assesses Husky’s reserves process to ensure that it is complete.

Summary of Oil and Natural Gas Reserves
As at December 31, 2016
Forecast Prices and Costs

Canada

	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	73.2	64.0	56.9	54.8	140.6	132.3	270.7	251.1
Developed Non-producing	2.1	1.6	6.0	5.6	19.3	17.5	27.4	24.7
Undeveloped	5.7	4.9	0.3	0.3	488.3	418.5	494.3	423.6
Total Proved	81.0	70.5	63.3	60.6	648.1	568.2	792.4	699.4
Probable	167.9	139.6	20.1	19.3	1,274.6	998.8	1,462.5	1,157.8
Total Proved Plus Probable	**248.9**	**210.1**	**83.3**	**80.0**	**1,922.7**	**1,567.0**	**2,254.9**	**1,857.1**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Proved						
Developed Producing	1,162.5	1,088.5	41.1	32.5	505.5	465.0
Developed Non-producing	20.1	16.8	0.9	0.7	31.6	28.1
Undeveloped	334.2	282.0	3.2	2.5	553.1	473.1
Total Proved	1,516.9	1,387.3	45.1	35.7	1,090.3	966.3
Probable	423.1	365.0	8.2	5.9	1,541.2	1,224.5
Total Proved Plus Probable	**1,939.9**	**1,752.3**	**53.3**	**41.5**	**2,631.5**	**2,190.7**

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	2.0	1.6	—	—	—	—	2.0	1.6
Developed Non-producing	—	—	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—	—	—
Total Proved	2.0	1.6	—	—	—	—	2.0	1.6
Probable	—	—	—	—	—	—	—	—
Total Proved Plus Probable	**2.0**	**1.6**	**—**	**—**	**—**	**—**	**2.0**	**1.6**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Proved						
Developed Producing	399.9	377.4	13.6	12.8	82.3	77.3
Developed Non-producing	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—
Total Proved	399.9	377.4	13.6	12.8	82.3	77.3
Probable	118.0	111.6	4.3	4.1	24.0	22.7
Total Proved Plus Probable	**517.9**	**489.0**	**17.9**	**16.9**	**106.3**	**100.0**

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	—	—	—	—	—	—
Developed Non-producing	167.2	126.1	7.2	4.9	35.0	25.9
Undeveloped	101.0	76.1	—	—	16.8	12.7
Total Proved	268.2	202.2	7.2	4.9	51.9	38.6
Probable	139.6	81.7	2.1	0.6	25.3	14.2
Total Proved Plus Probable	**407.8**	**283.9**	**9.2**	**5.5**	**77.2**	**52.8**

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	75.2	65.6	56.9	54.8	140.6	132.3	272.7	252.7
Developed Non-producing	2.1	1.6	6.0	5.6	19.3	17.5	27.4	24.7
Undeveloped	5.7	4.9	0.3	0.3	488.3	418.5	494.3	423.6
Total Proved	83.0	72.1	63.3	60.6	648.1	568.2	794.4	701.0
Probable	167.9	139.6	20.1	19.3	1,274.6	998.8	1,462.5	1,157.8
Total Proved Plus Probable	**250.9**	**211.8**	**83.3**	**80.0**	**1,922.7**	**1,567.0**	**2,256.9**	**1,858.8**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Proved						
Developed Producing	1,562.5	1,465.9	54.7	45.3	587.8	542.4
Developed Non-producing	187.3	142.9	8.1	5.6	66.7	54.0
Undeveloped	435.2	358.1	3.2	2.5	570.0	485.8
Total Proved	2,185.0	1,966.8	65.9	53.4	1,224.4	1,082.2
Probable	680.6	558.3	14.5	10.6	1,590.5	1,261.4
Total Proved Plus Probable	**2,865.7**	**2,525.1**	**80.4**	**64.0**	**2,814.9**	**2,343.6**

Summary of Net Present Values of Future Net Revenue - Before Income Taxes and Discounted
As at December 31, 2016
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	2,070	5,603	5,519	5,102	4,700	11.87
Developed Non-producing	66	244	297	306	298	10.56
Undeveloped	14,196	6,706	3,982	2,642	1,851	8.42
Total Proved	16,331	12,553	9,798	8,049	6,850	10.14
Probable	45,619	16,160	7,727	4,311	2,607	6.31
Total Proved Plus Probable	**61,950**	**28,713**	**17,525**	**12,360**	**9,456**	**8.00**

China

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	**0%**	**5%**	**10%**	**15%**	**20%**	**($/boe)**
Proved						
Developed Producing	4,859	4,168	3,630	3,203	2,859	46.94
Developed Non-producing	—	—	—	—	—	—
Undeveloped	—	—	—	—	—	—
Total Proved	4,859	4,168	3,630	3,203	2,859	46.94
Probable	1,483	998	692	493	360	30.48
Total Proved Plus Probable	**6,342**	**5,166**	**4,322**	**3,696**	**3,219**	**43.20**

Indonesia

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	**0%**	**5%**	**10%**	**15%**	**20%**	**($/boe)**
Proved						
Developed Producing	—	—	—	—	—	—
Developed Non-producing	702	559	458	384	328	17.67
Undeveloped	246	165	110	72	45	8.71
Total Proved	948	724	568	456	373	14.72
Probable	531	369	265	195	147	18.61
Total Proved Plus Probable	**1,479**	**1,093**	**833**	**652**	**520**	**15.77**

Total

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	**0%**	**5%**	**10%**	**15%**	**20%**	**($/boe)**
Proved						
Developed Producing	6,929	9,772	9,149	8,305	7,559	16.87
Developed Non-producing	768	802	755	690	627	13.97
Undeveloped	14,441	6,871	4,092	2,714	1,896	8.42
Total Proved	22,138	17,445	13,996	11,709	10,081	12.93
Probable	47,634	17,526	8,684	4,999	3,114	6.88
Total Proved Plus Probable	**69,772**	**34,971**	**22,680**	**16,707**	**13,195**	**9.68**

Summary of Net Present Values of Future Net Revenue - After Income Taxes and Discounted
As at December 31, 2016
Forecast Prices and Costs

Canada

	After Income Taxes and Discounted at (%/year)				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed Producing	1,610	4,128	4,040	3,724	3,426
Developed Non-producing	70	196	232	236	229
Undeveloped	10,349	4,786	2,773	1,786	1,206
Total Proved	12,029	9,110	7,046	5,746	4,860
Probable	33,242	11,528	5,354	2,872	1,647
Total Proved Plus Probable	**45,271**	**20,637**	**12,400**	**8,618**	**6,507**

China

	After Income Taxes and Discounted at (%/year)				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed Producing	4,251	3,651	3,183	2,811	2,511
Developed Non-producing	—	—	—	—	—
Undeveloped	—	—	—	—	—
Total Proved	4,251	3,651	3,183	2,811	2,511
Probable	1,179	792	548	389	283
Total Proved Plus Probable	**5,431**	**4,443**	**3,730**	**3,200**	**2,793**

Indonesia

	After Income Taxes and Discounted at (%/year)				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed Producing	—	—	—	—	—
Developed Non-producing	542	439	366	311	269
Undeveloped	217	144	95	61	36
Total Proved	759	584	461	371	304
Probable	405	287	210	157	120
Total Proved Plus Probable	**1,164**	**871**	**671**	**529**	**424**

Total

	After Income Taxes and Discounted at (%/year)				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed Producing	5,861	7,778	7,223	6,535	5,936
Developed Non-producing	612	635	598	547	497
Undeveloped	10,566	4,931	2,869	1,847	1,242
Total Proved	17,039	13,344	10,689	8,929	7,675
Probable	34,826	12,607	6,112	3,418	2,049
Total Proved Plus Probable	**51,866**	**25,951**	**16,801**	**12,346**	**9,725**

Total Future Net Revenue for Total Proved Plus Probable Reserves - Undiscounted
As at December 31, 2016
Forecast Prices and Costs

($ millions)	Revenue	Royalties	Operating Costs	Develop-ment Costs	Abandon-ment and Reclama-tion Costs	Future Net Revenue Before Income Taxes	Income Taxes	Future Net Revenue After Income Taxes
Canada								
Total Proved	62,433	8,534	22,947	6,734	7,887	16,331	4,302	12,029
Total Proved Plus Probable	**188,784**	**35,906**	**57,625**	**25,175**	**8,129**	**61,950**	**16,679**	**45,271**
China								
Total Proved	5,640	—	527	46	208	4,859	608	4,251
Total Proved Plus Probable	**7,280**	**—**	**684**	**46**	**208**	**6,342**	**912**	**5,431**
Indonesia								
Total Proved	2,205	—	1,144	113	—	948	189	759
Total Proved Plus Probable	**3,156**	**—**	**1,457**	**220**	**—**	**1,479**	**316**	**1,164**
Total								
Total Proved	70,278	8,534	24,619	6,892	8,095	22,138	5,099	17,039
Total Proved Plus Probable	**199,220**	**35,906**	**59,766**	**25,440**	**8,336**	**69,772**	**17,906**	**51,866**

Future Net Revenue by Product Type
As at December 31, 2016
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	1,547	11.19	68	42.35	—	—	1,616	11.55
Heavy Crude Oil	206	3.34	—	—	—	—	206	3.34
Bitumen	7,076	12.45	—	—	—	—	7,076	12.45
Total Oil	8,830	11.50	68	42.35	—	—	8,898	11.56
Conventional Natural Gas	968	4.89	3,562	47.04	568	14.72	5,098	16.31
Total Proved	9,798	10.14	3,630	46.94	568	14.72	13,996	12.93
Total Proved Plus Probable								
Light & Medium Crude Oil	3,231	11.43	68	42.35	—	—	3,299	11.60
Heavy Crude Oil	551	6.79	—	—	—	—	551	6.79
Bitumen	12,411	7.92	—	—	—	—	12,411	7.92
Total Oil	16,193	8.39	68	42.35	—	—	16,261	8.42
Conventional Natural Gas	1,332	5.13	4,254	43.22	833	15.77	6,419	15.61
Total Proved Plus Probable	17,525	8.00	4,322	43.20	833	15.77	22,680	9.68

[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 2016, see the section "Disclosure of Oil and Gas Activities" in this AIF.

	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					
2016	43.32	43.69	52.99	39.55	32.61
Forecast					
2017	55.00	56.00	68.24	54.06	47.24
2018	60.90	61.90	73.16	59.67	52.51
2019	65.47	66.47	76.25	63.48	56.16
2020	69.13	70.50	79.37	66.27	58.75
2021	73.21	74.58	82.56	69.22	61.45
2022	75.19	76.56	84.85	71.34	63.43
2023	77.19	78.56	87.15	73.45	65.48
2024	79.23	80.60	89.50	75.62	67.47
2025	81.28	82.68	91.89	77.82	69.43
2026	83.39	84.98	94.01	80.00	71.65
Thereafter[1]					

	Bitumen	Natural Gas	Natural Gas Liquids		
	Hardisty WCS (Cdn $/bbl)	**NIT (Cdn $/GJ)**	**Edmonton Propane (Cdn $/bbl)**	**Edmonton Butane (Cdn $/bbl)**	**Edmonton Condensate (Cdn $/bbl)**
Historical					
2016	39.05	1.98	12.72	33.76	55.59
Forecast					
2017	53.38	3.43	24.82	47.01	70.95
2018	58.95	3.17	26.16	52.53	75.40
2019	62.70	3.26	27.70	54.57	78.72
2020	65.48	3.67	29.10	57.49	81.52
2021	68.39	3.86	30.61	60.83	84.77
2022	70.49	3.97	31.80	62.55	87.17
2023	72.58	4.11	33.01	64.24	89.44
2024	74.73	4.23	34.26	66.00	91.86
2025	76.88	4.31	35.54	67.74	94.67
2026	79.08	4.41	36.73	69.31	96.73
Thereafter[1]					

	Asia Pacific				
	China		Indonesia		
	Daqing Crude Oil (U.S. $/bbl)	Natural Gas (U.S. $/mcf)[2]	Natural Gas (U.S. $/mcf)[2]	Inflation rates[3]	Exchange rates[4]
Historical					
2016	40.86	10.25	N/A	—	0.76
Forecast					
2017	52.00	10.28	6.59	—	0.76
2018	57.82	10.46	6.78	2.00	0.79
2019	62.31	11.14	6.93	2.00	0.82
2020	66.26	12.05	7.07	2.00	0.83
2021	70.25	11.77	7.23	2.00	0.85
2022	72.15	10.33	7.41	2.00	0.85
2023	74.05	10.33	7.52	2.00	0.85
2024	76.00	10.33	7.63	2.00	0.85
2025	77.99	10.33	7.71	2.00	0.85
2026	80.20	10.33	7.70	2.00	0.85
Thereafter[1]					

(1) Prices thereafter are escalated at 2 percent per annum except for sales pursuant to GSAs where prices are escalated as per contract.

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

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

(4) Exchange rate 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)*	Conven-tional Natural Gas *(bcf)*	Coal Bed Methane *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Canada - Western Canada								
End of 2015	65.9	112.6	625.0	803.4	1,721.1	11.9	50.9	1,143.2
Technical Revisions	3.8	14.6	45.7	64.1	38.1	1.8	(1.6)	69.1
Economic Factors	(0.4)	(1.9)	(0.2)	(2.5)	(10.5)	—	(0.3)	(4.5)
Acquisitions	0.1	—	3.0	3.1	8.4	—	0.1	4.6
Dispositions	(27.2)	(44.3)	—	(71.5)	(91.3)	(13.7)	(1.3)	(90.4)
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	2.1	10.3	12.3	13.1	—	0.1	14.7
Production	(8.6)	(19.8)	(35.6)	(64.0)	(161.9)	—	(2.9)	(93.9)
End of 2016	**33.5**	**63.3**	**648.1**	**744.9**	**1,516.9**	**—**	**45.1**	**1,042.8**
Canada - Atlantic Region								
End of 2015	55.3	—	—	55.3	—	—	—	55.3
Technical Revisions	4.3	—	—	4.3	—	—	—	4.3
Economic Factors	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—
Production	(12.1)	—	—	(12.1)	—	—	—	(12.1)
End of 2016	**47.5**	**—**	**—**	**47.5**	**—**	**—**	**—**	**47.5**
China								
End of 2015	3.8	—	—	3.8	339.4	—	13.3	73.7
Technical Revisions	0.6	—	—	0.6	102.1	—	2.5	20.1
Economic Factors	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—
Production	(2.4)	—	—	(2.4)	(41.5)	—	(2.2)	(11.5)
End of 2016	**2.0**	**—**	**—**	**2.0**	**399.9**	**—**	**13.6**	**82.3**
Indonesia								
End of 2015	—	—	—	—	268.2	—	7.2	51.9
Technical Revisions	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—
End of 2016	**—**	**—**	**—**	**—**	**268.2**	**—**	**7.2**	**51.9**

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conven-tional Natural Gas *(bcf)*	Coal Bed Methane *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Libya								
End of 2015	0.01	—	—	0.01	—	—	—	0.01
Technical Revisions	0.00	—	—	0.00	—	—	—	0.00
Economic Factors	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	(0.01)	—	—	(0.01)	—	—	—	(0.01)
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—
End of 2016	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total								
End of 2015	124.9	112.6	625.0	862.5	2,328.7	11.9	71.5	1,324.0
Technical Revisions	8.7	14.6	45.7	69.0	140.1	1.8	0.9	93.5
Economic Factors	(0.4)	(1.9)	(0.2)	(2.5)	(10.5)	—	(0.3)	(4.5)
Acquisitions	0.1	—	3.0	3.1	8.4	—	0.1	4.6
Dispositions	(27.3)	(44.3)	—	(71.5)	(91.3)	(13.7)	(1.3)	(90.4)
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	2.1	10.3	12.3	13.1	—	0.1	14.7
Production	(23.1)	(19.8)	(35.6)	(78.5)	(203.5)	—	(5.1)	(117.6)
End of 2016	**83.0**	**63.3**	**648.1**	**794.4**	**2,185.0**	**—**	**65.9**	**1,224.4**

At December 31, 2016, the Company's proved oil and gas reserves were 1,224 mmboe, down from 1,324 mmboe at the end of 2015. The Company's 2016 reserve replacement ratio, defined as net additions divided by total production during the period, was 19 percent excluding economic revisions (15 percent including economic revisions). Major changes to proved reserves in 2016 included:

- Disposition of 90 mmboe in the Plains area. The total acquisitions were 5 mmboe, mainly in the Heavy Oil and Gas thermal bitumen area and Western Canada gas plays;
- 47 mmbbls were added as technical revisions to the Heavy Oil and Gas thermal bitumen projects;
- An additional 102 bcf of conventional natural gas were added in proved developed producing reserves for Liwan 3-1 as technical revisions; and
- Additional future drilling locations at Tucker added extensions of 9 mmbbls of bitumen in proved undeveloped reserves.

Reconciliation of Gross Probable Reserves

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conven-tional Natural Gas *(bcf)*	Coal Bed Methane *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Canada - Western Canada								
End of 2015	13.7	34.3	1,279.9	1,327.9	476.9	0.7	11.8	1,419.3
Technical Revisions	(0.6)	(7.4)	29.4	21.4	(25.2)	2.1	(3.2)	14.4
Economic Factors	—	(0.1)	0.1	0.1	(3.7)	—	—	(0.6)
Revisions - Transfer to Proved	—	(0.8)	(44.5)	(45.3)	(5.8)	—	(0.1)	(46.3)
Acquisitions	—	—	8.0	8.0	0.1	—	—	8.0
Dispositions	(5.1)	(6.5)	—	(11.6)	(19.7)	(2.8)	(0.3)	(15.7)
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	0.5	1.7	2.3	0.5	—	—	2.3
Production	—	—		—	—	—	—	—
End of 2016	**8.2**	**20.1**	**1,274.6**	**1,302.8**	**423.1**	**—**	**8.2**	**1,381.5**
Canada - Atlantic Region								
End of 2015	113.7	—	—	113.7	—	—	—	113.7
Technical Revisions	(1.1)	—	—	(1.1)	—	—	—	(1.1)
Economic Factors	—	—	—	—	—	—	—	—
Revisions - Transfer to Proved	(0.7)	—	—	(0.7)	—	—	—	(0.7)
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	47.8	—	—	47.8	—	—	—	47.8
Production	—	—	—	—	—	—	—	—
End of 2016	**159.7**	**—**	**—**	**159.7**	**—**	**—**	**—**	**159.7**
China								
End of 2015	0.2	—	—	0.2	190.1	—	6.2	38.2
Technical Revisions	(0.2)	—	—	(0.2)	—	—	—	(0.3)
Economic Factors	—	—	—	—	—	—	—	—
Revisions - Transfer to Proved	—	—	—	—	(72.1)	—	(1.9)	(13.9)
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—
End of 2016	**—**	**—**	**—**	**—**	**118.0**	**—**	**4.3**	**24.0**
Indonesia								
End of 2015	—	—	—	—	91.5	—	1.7	16.9
Technical Revisions	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—
Revisions - Transfer to Proved	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	48.1	—	0.4	8.4
Extensions & Improved Recovery	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—
End of 2016	—	—	**—**	**—**	139.6	**—**	**2.1**	**25.3**

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conven-tional Natural Gas *(bcf)*	Coal Bed Methane *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Libya								
End of 2015	—	—	—	—	—	—	—	—
Technical Revisions	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—
Revisions - Transfer to Proved	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—
End of 2016	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total								
End of 2015	127.7	34.3	1,279.9	1,441.9	758.5	0.7	19.7	1,588.1
Technical Revisions	(1.9)	(7.4)	29.4	20.1	(25.2)	2.1	(3.2)	13.1
Economic Factors	—	(0.1)	0.1	0.1	(3.7)	—	—	(0.6)
Revisions - Transfer to Proved	(0.7)	(0.8)	(44.5)	(46.0)	(77.9)	—	(2.0)	(61.0)
Acquisitions	—	—	8.0	8.0	0.1	—	—	8.0
Dispositions	(5.1)	(6.5)	—	(11.6)	(19.7)	(2.8)	(0.3)	(15.7)
Discoveries	—	—	—	—	48.1	—	0.4	8.4
Extensions & Improved Recovery	47.8	0.5	1.7	50.0	0.5	—	—	50.1
Production	—	—	—	—	—	—	—	—
End of 2016	**167.9**	**20.1**	**1,274.6**	**1,462.5**	**680.6**	**—**	**14.5**	**1,590.5**

Major changes to probable reserves in 2016 included:

- Disposition of 16 mmboe in the Plains area. Total acquisitions were 8 mmboe in the Heavy Oil and Gas business unit thermal bitumen area;
- 29 mmbbls in the Heavy Oil and Gas thermal bitumen projects (3 mmbbls Tucker) were added as technical revisions and an additional 45 mmbbls (9 mmbbls Tucker) were transferred to proved reserves;
- Extensions and improved recovery as a result of adding additional development locations in Atlantic Region added 48 mmbbls of light and medium oil;
- Negative technical revisions to conventional natural gas of 25 bcf were primarily a result of a change in development plans in Western Canada;
- In China 72 bcf of conventional natural gas were transferred to proved reserves; and
- Discoveries of 48 bcf of conventional natural gas are a result of receiving government approval for the Plan of Development for a new field in Indonesia.

Reconciliation of Gross Proved Plus Probable Reserves

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conven-tional Natural Gas *(bcf)*	Coal Bed Methane *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Canada - Western Canada								
End of 2015	79.6	146.9	1,904.8	2,131.3	2,198.0	12.5	62.7	2,562.5
Technical Revisions	3.2	7.2	75.1	85.5	12.9	3.9	(4.8)	83.5
Economic Factors	(0.3)	(2.0)	(0.1)	(2.4)	(14.2)	—	(0.3)	(5.1)
Revisions - Transfer to Proved	—	(0.8)	(44.5)	(45.3)	(5.8)	—	(0.1)	(46.3)
Acquisitions	0.1	—	11.0	11.1	8.5	—	0.1	12.7
Dispositions	(32.3)	(50.8)	—	(83.1)	(111.0)	(16.4)	(1.7)	(106.1)
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	2.6	12.0	14.6	13.6	—	0.1	17.0
Production	(8.6)	(19.8)	(35.6)	(64.0)	(161.9)	—	(2.9)	(93.9)
End of 2016	**41.7**	**83.3**	**1,922.7**	**2,047.7**	**1,939.9**	**—**	**53.3**	**2,424.3**
Canada - Atlantic Region								
End of 2015	169.0	—	—	169.0	—	—	—	169.0
Technical Revisions	3.2	—	—	3.2	—	—	—	3.2
Economic Factors	—	—	—	—	—	—	—	—
Revisions - Transfer to Proved	(0.7)	—	—	(0.7)	—	—	—	(0.7)
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	47.8	—	—	47.8	—	—	—	47.8
Production	(12.1)	—	—	(12.1)	—	—	—	(12.1)
End of 2016	**207.2**	**—**	**—**	**207.2**	**—**	**—**	**—**	**207.2**
China								
End of 2015	4.0	—	—	4.0	529.5	—	19.6	111.8
Technical Revisions	0.4	—	—	0.4	102.1	—	2.5	19.9
Economic Factors	—	—	—	—	—	—	—	—
Revisions - Transfer to Proved	—	—	—	—	(72.1)	—	(1.9)	(13.9)
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—
Production	(2.4)	—	—	(2.4)	(41.5)	—	(2.2)	(11.5)
End of 2016	**2.0**	**—**	**—**	**2.0**	**517.9**	**—**	**17.9**	**106.3**
Indonesia								
End of 2015	—	—	—	—	359.7	—	8.8	68.8
Technical Revisions	—	—	—	—	—	—	—	—
Economic Factors	—	—	—	—	—	—	—	—
Revisions - Transfer to Proved	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—	—
Discoveries	—	—	—	—	48.1	—	0.4	8.4
Extensions & Improved Recovery	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—
End of 2016	—	—	**—**	**—**	407.8	**—**	**9.2**	**77.2**

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conven-tional Natural Gas *(bcf)*	Coal Bed Methane *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Libya								
End of 2015	0.01	—	—	0.01	—	—	—	0.01
Technical Revisions	0.00	—	—	0.00	—	—	—	0.00
Economic Factors	—	—	—	—	—	—	—	—
Revisions - Transfer to Proved	—	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—	—
Dispositions	(0.01)	—	—	(0.01)	—	—	—	(0.01)
Discoveries	—	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—	—
End of 2016	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Total								
End of 2015	252.6	146.9	1,904.8	2,304.4	3,087.2	12.5	91.1	2,912.1
Technical Revisions	6.8	7.2	75.1	89.1	115.0	3.9	(2.3)	106.6
Economic Factors	(0.3)	(2.0)	(0.1)	(2.4)	(14.2)	—	(0.3)	(5.1)
Revisions - Transfer to Proved	(0.7)	(0.8)	(44.5)	(46.0)	(77.9)	—	(2.0)	(61.0)
Acquisitions	0.1	—	11.0	11.1	8.5	—	0.1	12.7
Dispositions	(32.3)	(50.8)	—	(83.1)	(111.0)	(16.4)	(1.7)	(106.1)
Discoveries	—	—	—	—	48.1	—	0.4	8.4
Extensions & Improved Recovery	47.8	2.6	12.0	62.4	13.6	—	0.1	64.8
Production	(23.1)	(19.8)	(35.6)	(78.5)	(203.5)	—	(5.1)	(117.6)
End of 2016	**250.9**	**83.3**	**1,922.7**	**2,256.9**	**2,865.7**	**—**	**80.4**	**2,814.9**

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 58 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 full. Approximately 28 percent of Husky's gross proved undeveloped reserves are assigned to 9 heavy oil projects in the Lloydminster area that are classified as bitumen. Approximately 10 percent of Husky's gross proved undeveloped reserves are assigned to the liquids-rich Ansell area, and approximately three percent of Husky's gross proved undeveloped reserves are assigned to the Madura area, a reduction from last year's nine percent with the transfer of reserves in the BD pool to proved developed as the project nears start-up.

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 conventional reserves over five and seven year time periods, respectively. As at December 31, 2016, there were no material proved undeveloped conventional reserves that have remained undeveloped for greater than five years, except for the Company's thermal bitumen reserves. The proved undeveloped thermal bitumen reserves are scheduled to be developed over the next one to 40 years to fully utilize the steam plant and processing capacity over the life of the current facilities. The probable undeveloped bitumen reserves are scheduled to be developed over the next 40 years which include facility debottlenecks, expansions and additions.

Proved Undeveloped Reserves[1]

	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**
2014	2.3	27.8	8.9	16.7	70.8	299.0	82.0	343.5
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

	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**
2014	104.0	648.7	5.6	20.6	104.9	472.2
2015	172.5	611.7	0.7	10.4	214.8	595.6
2016	1.6	435.2	—	3.2	9.4	570.0

(1) Prior year product types have been updated in accordance with the 2015 amendments to NI 51-101 F1.

Probable Undeveloped Reserves[1]

	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**
2014	54.5	128.6	7.6	28.8	41.5	1,468.1	103.6	1,625.5
2015	—	106.4	—	4.9	0.1	1,235.2	0.1	1,346.6
2016	47.8	133.7	—	0.1	1.3	1,234.0	49.1	1,367.7

	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**
2014	71.6	429.5	3.2	12.7	118.7	1,709.7
2015	143.0	405.4	1.8	8.0	25.7	1,422.2
2016	48.1	345.4	0.4	3.4	57.5	1,428.7

(1)Prior year product types have been updated in accordance with the 2015 amendments to NI 51-101 F1.

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, 2016.

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, 2016:

	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)*
2017	735	1,001	42	42	113	179	890	1,222
2018	467	1,317	4	4	—	40	471	1,362
2019	422	1,462	—	—	—	—	422	1,462
2020	395	960	—	—	—	—	395	960
2021	431	973	—	—	—	—	431	973
Remaining	4,284	19,463	—	—	—	—	4,284	19,463
Total	**6,734**	**25,175**	**46**	**46**	**113**	**220**	**6,892**	**25,440**

Abandonment and reclamation costs are not included in the above amounts, but they were included in prior years' disclosures.

Production Estimates
Yearly Production Estimates for 2017

	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	46.9	38.9	121.5	207.3	348.9	7.9	273.4
Total Gross Probable	7.5	3.5	6.2	17.2	20.4	0.3	20.9
Total Gross Proved Plus Probable	**54.4**	**42.4**	**127.8**	**224.5**	**369.4**	**8.2**	**294.3**
China							
Total Gross Proved	5.4	—	—	5.4	162.1	6.8	39.3
Total Gross Probable	—	—	—	—	—	0.4	0.4
Total Gross Proved Plus Probable	**5.4**	—	—	5.4	**162.1**	**7.2**	**39.6**
Indonesia							
Total Gross Proved	—	—	—	—	24.9	1.2	5.3
Total Gross Probable	—	—	—	—	7.6	—	1.3
Total Gross Proved Plus Probable	**—**	—	—	—	**32.4**	**1.2**	**6.6**
Total							
Total Gross Proved	52.4	38.9	121.5	212.8	536.0	15.9	318.0
Total Gross Probable	7.5	3.5	6.2	17.2	28.0	0.7	22.6
Total Gross Proved Plus Probable	**59.8**	42.4	127.8	230.0	**563.9**	**16.6**	**340.5**

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

Infrastructure and Marketing

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 Operated Infrastructure

Husky has been involved in the gathering, transporting and storage of heavy crude oil in the Lloydminster area since the early 1960s. Historically, Husky owned and operated the Cold Lake Gathering System and the Saskatchewan Gathering System. 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 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. The blended crude oil is transported to eastern and southern markets on these pipelines.

During 2016, the Company completed the sale of 65 percent of its ownership interest in select midstream assets discussed above 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, HMLP, of which the Company owns 35 percent, PAH owns 48.75 percent and CKI owns 16.25 percent. The Company will remain the operator of the assets.

The transaction enabled the Company to further strengthen its balance sheet while maintaining operatorship and preserving the integration between its heavy oil production, marketing and refining assets.

In 2017, HMLP expects to actively expand the gathering system network and Hardisty terminal to support production growth in the area and further compliment the Company’s heavy oil and bitumen production. The assets will continue to 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 Upgrader or 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 heavy crude oil 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 also enabled the Company to sell heavy crude oil 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 to a large extent been insulated from 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 upgrading and refining assets. To date, the Company has been able to avoid any production shut-ins. 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 carefully 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, the Company 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. Results from the natural gas storage business are included in Upstream Infrastructure and Marketing.

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 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 NGLs sourced from the Company's own production and third-party production. Light crude oil is acquired for processing by the Company's refinery at Prince George, British Columbia and at Lima, Ohio. 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 assets managed, 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. Results from the Company's commodity marketing business are included in Upstream Infrastructure and Marketing.

Downstream Operations

U.S. Refining and Marketing

Lima, Ohio Refinery

The Lima Refinery, located in Ohio between Toledo and Dayton, has an atmospheric crude throughput capacity of 165,000 bbls/day and an operating capacity of 140,000 - 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. This includes Canadian synthetic crudes, including Husky Synthetic Blend ("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 2016, crude oil feedstock throughput at the Lima Refinery averaged 129 mbbls/day. This throughput was reduced from normal operations due to a major turnaround in the spring of 2016. In addition, the isocracker was not operational at full capacity until the third quarter of 2016 due to the fire incident in the first quarter of 2015. Production in 2016 consisted of gasoline averaging 67 mbbls/day, total distillates averaging 54 mbbls/day and total other products averaging 18 mbbls/day.

The Lima Refinery continues to progress reliability and profitability improvement projects. 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. Regulatory approval was granted by the U.S. Environmental Protection Agency ("EPA"). Current heavy crude oil feedstock capability is up to 10,000 bbls/day. The full scope of the project is expected to be completed in 2018.

BP-Husky Toledo, Ohio Refinery

The BP-Husky Toledo Refinery, in which the Company holds a 50 percent interest, has a nameplate capacity of 160,000 bbls/day and an operating capacity of 135,000 - 145,000 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.

The BP-Husky Toledo Refinery successfully completed a planned turnaround in the third quarter of 2016. A feedstock optimization project, which was designed to improve the Refinery's ability to process High-TAN crude, was also completed during the turnaround, which has given the Refinery the ability to process 65,000 bbl/day of High-TAN crude. This supports the strategic intent to process bitumen from the Sunrise Energy Project. As of January 1, 2017, the Company has been marketing its share of the joint operation's refined product.

During the year ended December 31, 2016, the Company's share of crude oil feedstock throughput averaged 62 mbbls/day, production of gasoline averaged 37 mbbls/day, distillates averaged 18 mbbls/day and other fuel and feedstock averaged 7 mbbls/day. Production volumes were lower than 2015 due to the 71 day turnaround.

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 mbbls/day of synthetic crude oil, diluents and ultra low sulphur diesel.

Production at the Upgrader averaged 53 mbbls/day of synthetic crude oil, 14 mbbls/day of diluent and 6 mbbls/day of ultra low sulphur diesel in 2016. In addition, the Upgrader also produced, as by-products of its upgrading operations, approximately 331 long tons/day of sulphur and 876 long tons/day of petroleum coke during 2016. 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 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 Husky refinery at Prince George, British Columbia and are also acquired from third-party refiners and marketed through Husky retail and commercial petroleum outlets and through direct marketing to third-party dealers and end users. Asphalt and residual products are produced at Husky'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 Company's light oil refinery in Prince George, British Columbia, provides refined products to the Company and third-party retail outlets in the central and northern regions of the province. Feedstock is delivered to the Refinery by pipeline from northeastern British Columbia. The Prince George Refinery production is equal to approximately 21 percent of the Company's total refined product supply requirements.

The Refinery produces all grades of unleaded gasoline, seasonal diesel fuels, mixed propane and butane and heavy fuel oil. During 2016, Refinery throughput averaged 9.4 mbbls/day.

Lloydminster Asphalt Refinery

Husky's Asphalt Refinery in Lloydminster, Alberta processes heavy crude oil into asphalt products used in road construction and maintenance, and industrial asphalt products. The Refinery has a throughput capacity of 29 mbbls/day of heavy crude oil. 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 and the distillate stream is used by the Upgrader to make ultra low sulphur diesel fuel. The bulk distillates are hydrogen deficient and are transferred directly to the Upgrader and then treated for blending into the HSB stream. Residuals are a blend of medium and light distillate and gas oil streams, which are sold directly to customers typically as drilling and well fracturing fluids or used in asphalt cutbacks and emulsions.

Refinery throughput averaged 28 mbbls/day of blended heavy crude oil feedstock during 2016. In 2016, daily sales volumes of asphalt averaged 15 mbbls/day and daily sales volumes of residual and other products averaged 13 mbbls/day. Due to the seasonal demand for asphalt products, most Canadian 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, 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 has an asphalt distribution network which consists of emulsion plants and 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 its Prince George Refinery and uses independently operated terminals in British Columbia, Alberta and in Washington State.

The Company's sales to the U.S. and Eastern Canada accounted for over 50 percent of its total asphalt sales in 2016. Exported asphalt products are shipped as far as California and New York in the U.S. and Nova Scotia in Canada. The Company sold 5.2 mmbbls of asphalt in 2016.

Through the Pounder Emulsions division, the Company has a significant market share in Western Canada for road application emulsion products. Additional non-asphalt based road maintenance products are also marketed and distributed through Pounder Emulsions.

In 2017, the Company plans to increase asphalt modification capacity, expand retail sales in U.S. markets and market residual products as refinery feedstock.

Ethanol Plants

In September 2006, the Company commissioned an ethanol plant in Lloydminster, Saskatchewan. This 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. In 2016, ethanol production averaged 820,555 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 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 CO_2 capture facility. The plant is currently capturing CO_2 for use in the Company's non-thermal EOR projects.

Other Supply Arrangements

In addition to the refined petroleum products supplied by the Prince George Refinery of 3.3 mbbls/day and by the Husky Lloydminster Upgrader of 5.3 mbbls/day in 2016, the Company has an exclusive purchase agreement for refined products with Imperial Oil. During 2016, the Company purchased approximately 29.2 mbbls/day of refined petroleum products of which 26.5 mmbls/day were from the exclusive purchase agreement with Imperial Oil. The Company also acquired approximately 9.0 mbbls/day of refined petroleum products pursuant to exchange agreements with third-party refiners in addition to Imperial Oil.

Branded Petroleum Product Outlets and Commercial Distribution

As at December 31, 2016, there were 480 independently operated Husky-branded petroleum product outlets. These outlets include travel centres, convenience stores, cardlock operations and bulk distribution facilities located from the Ontario/Quebec border to the west coast of British Columbia. 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 Western Canada.

During 2015, the Company and Imperial Oil entered into a contractual agreement to create a single expanded truck transport network of approximately 160 sites. The agreement was approved by Canada's Competition Bureau in June 2016 and contract closing conditions were met late in the fourth quarter 2016. Progress continues to be made on the implementation of the agreement and the consolidation of the two networks is expected in the second half of 2017.

The Company's retail and commercial operating model is balanced by corporate-owned/lessee-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, proprietary and co-branded quick-serve restaurants. In addition to ethanol-blended gasoline, the Company offers diesel, propane and Chevron 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-branded petroleum outlets by province as of December 31, 2016:

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	2016 Total	2015 Total
Branded Petroleum Outlets							
Retail Owned Outlets	52	62	12	15	72	213	214
Leased	35	34	3	10	29	111	117
Independent Retailers	50	73	10	5	18	156	154
Total	**137**	**169**	**25**	**30**	**119**	**480**	**485**
Cardlocks [(1)]	23	30	5	7	19	84	85
Convenience Stores [(1)]	80	86	14	21	100	301	309
Restaurants	8	10	3	2	13	36	37

(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 Western 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,		
(mbbls/day)	2016	2015	2014
Gasoline	22.4	23.1	24.8
Diesel fuel	18.5	23.7	24.9
Liquefied Petroleum Gas	0.2	0.2	0.1
	41.1	47.0	49.8

INDUSTRY OVERVIEW

The operations of the oil and gas industry are governed by a considerable 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

The global crude oil supply and demand imbalance persisted during 2016. The increase in global crude oil supply was primarily attributable to growth from U.S. unconventional production and from Organization of Petroleum Exporting Countries ("OPEC"). Total U.S. crude oil production averaged an estimated 8.9 mmbbls/day in 2016, which is lower than the 9.4 mmbbls/day in 2015, but it still represents the second highest level of production since 1985. Crude oil production from OPEC averaged an estimated 39.3 mmbbls/day in 2016 and is expected to decrease to 32.5 mmbbls/day in 2017 as OPEC member countries agreed to reduce production in late 2016.[1]

In Canada, production continued to grow from the Western Canadian oil sands. However, growth was at a slower pace than anticipated primarily due to significant declines in benchmark crude oil prices. Further, production was severely affected by the Fort McMurray wildfires in the second quarter of 2016. In the Canadian Association of Petroleum Producers' ("CAPP") June 2016 publication, production in Canada was forecasted to increase from 4.0 mmbbls/day in 2015 to 5.5 mmbbls/day by 2030. The majority of production growth in Canada continues to be expected from the oil sands; however the estimates acknowledge the uncertainty that exists surrounding the global price environment.[2]

Total U.S. natural gas production decreased by approximately 4.8 percent in 2016 compared to 2015 as U.S. natural gas production reached a peak of 75 bcf/day in April 2015. Total Canadian natural gas production was impacted by high natural gas storage inventories due to a relatively warm winter in early 2016 and the Fort McMurray wildfires in May 2016.[3]

(1) "Short-Term Energy Outlook", January 2017, U.S. Energy Information Administration
(2) "Crude Oil Forecast, Markets and Pipelines", June 2016, Canadian Association of Petroleum Producers
(3) "Market Snapshot: Natural gas markets experience significant highs and lows in 2016", January 4, 2017, National Energy Board

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.

The imbalance between global crude oil supply and demand, led primarily by the growth from U.S. unconventional and OPEC production, lower economic growth forecasts from emerging markets and corresponding growth in global crude oil inventories, resulted in the continued weakness of key crude oil benchmarks. However, in late 2016, OPEC came to an agreement to reduce production by 1.2 mmbbls/day from their daily production, which has led to crude oil benchmarks showing signs of recovery. The price of West Texas Intermediate ("WTI") averaged U.S. $43.32/bbl in 2016 compared to U.S. $48.80/bbl in 2015, and the price of Brent averaged U.S. $43.69/bbl in 2016 compared to U.S. $52.46/bbl 2015.

Market Access

In order to accommodate the growing production of crude oil from Western Canada, the oil and gas industry continues to work with stakeholders to develop a strong network of transportation infrastructure for crude oil, 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 from Western Canada.[1]

(1) "Crude Oil Forecast, Markets and Pipelines", June 2016, Canadian Association of Petroleum Producers

Current pipeline capacity for crude oil exiting Western Canada totals 4.0 mmbbls/day. Several proposals have been announced that could increase current capacity by approximately 3.4 mmbbls/day during the next five years; however the in-service dates for many of the pipeline projects have already been delayed or could be further delayed due to extended regulatory processes and/or regulatory and policy changes[1]. The proposed pipeline projects, which are subject to various uncertainties, include the Keystone XL to the U.S. Gulf Coast, the Trans Mountain Expansion to Burnaby, British Columbia, the Enbridge Northern Gateway to Kitimat, British Columbia, the TransCanada Energy East to the east coast of Canada and the restoration of Enbridge's Line 3. In late 2016, the government of Canada granted approval for the Trans Mountain Expansion; the expansion is expected to commence construction in late 2017 and expected to go into service in late 2019.

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 pertaining to Husky operations in Western Canada averaged seven percent of gross revenue in 2016 compared to nine percent in 2015 primarily due to a higher percentage of production from thermal projects, which are at a lower royalty rate, and due to lower commodity prices which affected royalties on a sliding scale of price sensitivity. Royalty rates in the Atlantic Region averaged 15 percent in 2016 compared to 11 percent in 2015 primarily due to lower eligible royalty costs.

In early 2016, the Alberta government adopted the recommendation of its Royalty Review Panel. The new royalty framework preserves the existing royalty structure and rates for oil sands. It also creates a harmonized royalty formula for crude oil, natural gas and liquids that emulates a revenue minus cost system. The royalty changes will take effect in 2017 and only apply to new wells. The current Royalties on existing wells are to remain in place for 10 years.

The Canadian federal corporate income tax rate was 15 percent in 2016 and 2015. Provincial rates ranged between 11 percent and 16 percent in both 2016 and 2015.

Other Jurisdictions

Royalty rates in the Asia Pacific Region averaged six percent in 2016 compared to five percent in 2015.

Operations in the U.S are subject to the U.S. federal tax rate of 35 percent and various state-level taxes. 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, significant discovery and production licenses, 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 licenses 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

All phases of 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 GHG. Environmental regulations also require that wells, facilities and other properties associated with Husky's operations be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of pertinent regulatory authorities. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments.

Some of the topics that are or could in the future be subject to new or enhanced environmental regulation include:

- Air 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;
- calculation and regulation of carbon intensity for transportation fuels;
- fuel reformulation to support reduced transportation emissions;
- managing air pollutants at equipment and facility levels with the general goal of ensuring compliance with increasingly more stringent ambient air quality standards;
- potential for a moratorium 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; and
- land use.

Water

Extensive 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; and
- fluid transport, handling, and storage.

Water withdrawals, in particular freshwater withdrawals, are regulated in all of the 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 licenced water withdrawals to support operations. 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 identify and mitigate these risks.

Migratory Birds

Canada's oil and gas industry may affect migratory birds and bird habitat through land disturbance activities. Industry activities risk contravening the Migratory Bird Convention Act ("MBCA") and supporting legislation that prohibits the disturbance and destruction of migratory birds, their eggs and/or nests. In 2016, the Environmental Enforcement Act 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 stewardship of migratory birds through developed standards and additional training.

Air and Climate Change

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 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 performance standards; and
- other regulatory measures including low carbon fuel and renewable fuel standards.

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 at its Atlantic Region assets. Climate change is expected to increase 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. Husky's Atlantic Region business unit has a robust ice management program that uses a range of resources, including a dedicated ice surveillance aircraft, and works with government agencies including Environment Canada, the Coast Guard and Canadian Ice Service. Regular ice surveillance flights commence in February each year and continue until the threat of ice has abated. In addition, Atlantic Region operators employ a series of supply and support vessels to actively manage ice and icebergs.

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.

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. The Agreement includes pledges from 195 countries including all major emitters globally to reduce emissions such that temperature increases are limited to "well below 2°C above pre-industrial levels and to pursue efforts to limit the temperature increase to 1.5 °C." There is a commitment to review and increase pledges every five years under the Paris Agreement. Canada approved the Paris Agreement in October 2016.

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") with the objective 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 SO_2 for 2020 and 2025 were announced in October 2016. Work has also started to develop new CAAQS for nitrogen dioxide ("NO_2") for 2020 and 2025.

The first tranche of the Multi-Sector Air Pollutants Regulations was published in the Canada Gazette, Part II 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. 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 all Canadian Upstream and Downstream oil and gas facilities within Husky 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 and design standards for both existing and new equipment units.

In October 2016, the Canadian federal government announced its plan for a minimum carbon price in Canada. The plan is to set a national floor price on carbon at $10 per tonne of carbon dioxide equivalent ("CO_2e") in 2018 and increase it to $50 per tonne of CO_2e by 2022. Provinces have to meet or exceed that floor price either through a direct price on carbon or a cap-and-trade system. The entire Canadian economy will be impacted by this carbon pricing policy and therefore all aspects and levels of government are engaged.

The Federal Government of Canada is committing to reduce methane emissions from the oil and gas sector by 40 to 45 percent below 2012 levels by 2025. To implement this commitment, the federal government is expected to introduce regulations to reduce methane emissions from the oil and gas sector to address venting and fugitive emissions. The Canadian requirements are expected to cover emissions from the same sources that are subject to current and proposed U.S. regulatory requirements and will also require reductions from some unique Canadian sources such as heavy crude oil.

These regulations are expected to apply to new and existing sources, with the first requirements expected to come into force as early as 2020, and the remaining requirements expected to come into force by 2023.

The regulations are expected to apply to oil and gas facilities that are responsible for the extraction, production and processing and transportation of crude oil and natural gas. Regulatory requirements are expected to be designed to cover specific methane emission sources in Canada while minimizing administrative burden and providing the flexibility needed for efficient and effective operations in Canadian circumstances. Covered sources are expected to include: venting from wells and batteries (including associated gas at oil facilities), storage tanks, pneumatic devices, well completions, compressors and fugitive equipment leaks.

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:

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

Existing regulations provide that, facilities that emit over 100,000 tons of CO_2e per year, large final emitting facilities ("LFEs"), are required to reduce their emissions intensity by 20 percent by January 1, 2017. The price of the carbon levy (which may be used to make up for any shortfall in actual emissions intensity reductions) has increased from $15/$tCO_2$e to $20/$tCO_2$e for 2016 and $30/$tCO_2$e for 2017. As of January 1, 2018, LFEs will fall under a newly proposed carbon competitiveness regulation that will employ output-based allocations to benchmark facilities against peers. Industry and government are in ongoing consultations on the details of this regulation.

As of January 1, 2017 Alberta will be implementing a broad-based carbon price designed to cover emissions across all sectors, starting at $20 per tonne and moving to $30 per tonne on January 1, 2018. The government has signalled 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 tons of CO_2e per year will be exempt until January 1, 2023, to allow time for these facilities to reduce methane emissions under developing provincial and federal methane regulations. Consultations with industry and other stakeholders are ongoing to develop these regulations. Finally, total emissions from the oil sands will be capped at a maximum of 100 megatons 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 AER is working collaboratively to develop and implement an efficient and effective regulatory framework that achieves the Government of Alberta's methane emissions reduction outcome of 45 percent by 2025. Alberta intends to reduce methane emissions from oil and gas operations by 45 percent by 2025 using the following approaches:

1. Applying new emissions design standards to new Alberta facilities.
2. Improving measurement and reporting of methane emissions, as well as leak detection and repair requirements.
3. 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.

Alberta's reduction target and timeline match the commitments announced by the Canadian and American federal governments and are consistent with the AERs approach of protecting Alberta's economic competitiveness through alignment with North American environmental standards.

In October 2016, the Government of Saskatchewan released a climate change plan as an alternative approach to the federal government's announced carbon price. Saskatchewan's White Paper on Climate Change suggests balancing action on climate change issues by considering three basic approaches:

1. An emphasis on mitigation through emissions reductions: taxation regimes that attempt to change consumer behaviour, cap and trade systems, levies on large emitters, new regulations for the oil and gas sector and new regulations for power producers.
2. An emphasis on adaptation practices and technology: minimizing the impact of future climate events, reducing the vulnerability of provincial infrastructure, protecting community land and water resources, fostering an effective risk assessment and disaster recovery system, a better understanding of the risks associated with more frequent extreme climate events and improving our climate models to better predict the frequency and scale of these events.
3. A focus on innovation and technological development for domestic and international markets.

While looking at all three approaches, the Government of Saskatchewan believes the third option - innovation and technological development - offers the greatest potential for significant improvements in global GHG emissions while causing the least harm to the province's economy. Also, when the resource economy strengthens, the Government of Saskatchewan will move ahead with plans for a fund supported by a levy on large emitters, with the fund's expenditures limited to new technologies and innovation to reduce GHG emissions and not for general revenue.

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's Greenhouse Gas Industrial Reporting and Control Act will limit emissions from Liquefied Natural Gas ("LNG") facilities to 0.16 tons of GHG emissions for each 1 ton of LNG processed by the operator once implemented.

British Columbia currently has a $30 per ton carbon tax that is in place on fuel Husky uses and purchases in that jurisdiction, which affects all of the Company's operations in British Columbia. Additionally, British Columbia has a Renewable and Low Carbon Fuel Requirements Regulation in place that requires a reduction in the allowable carbon intensities of all 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 all major sectors of the economy, including annual reductions of up to five million tons CO_2 by 2050 in the oil and gas sector through a focus on methane emissions, carbon capture and storage as well as electrification. The B.C. government has not announced plans to update the provincial price on carbon beyond the current $30/tonne level at this time.

The Manitoba government released its Climate Change and Green Economy Action Plan in December 2015. Manitoba has pledged to cut GHG emissions from 2005 levels by one-third by 2030 and by one-half by 2050. The province will seek to be carbon-neutral by 2080. In September 2016, Manitoba Sustainable Development held a workshop on Carbon Pricing and Climate Change to explore key environmental and economic policy and design issues associated with carbon pricing, consider implications and trade-offs of each and identify important features for consideration in the province's approach, including options for revenue recycling, as well as adaptation and mitigation measures.

The Ontario government finalized the rules for its new cap and trade program in May 2016. The 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 Greenhouse Gas Reduction Account will receive proceeds from Ontario's cap and trade program. Funds from this account will be used for the purpose of reimbursing the Crown for costs incurred in administering the regulations in relation to GHG and for carrying out or supporting GHG reduction initiatives. The first auction is targeted for March 2017. Ontario intends to link its cap and trade program with Québec and California.

On November 9, 2016, the Government of Newfoundland and Labrador released *The Way Forward: A Vision for Sustainability and Growth in Newfoundland and Labrador*, indicating it is committed to making progress on the issue of climate change. The Newfoundland and Labrador ("NL") Government is working toward reducing provincial emissions of GHG to ten per cent below 1990 levels, by 2020. The NL Government is following the Federal Government's *Pan-Canadian Approach to Pricing Carbon Pollution* released to the first ministers in early October 2016; however the NL Government has yet to determine a specific mechanism to meet the federal mandate for carbon pricing. Jurisdictional issues are also being discussed between the provincial and federal governments as offshore oil and gas facilities operate on federal lands, under the jurisdiction of Offshore Petroleum Boards, and constitutionally are not under provincial jurisdiction.

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 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 tons per year of CO_2e emissions 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 Husky's U.S. operations.

The EPA has previously issued standards for the oil and gas production and transmission sector that, among other requirements, mandates the use of specified Reduced Emissions Completions ("REC") for hydraulically fractured natural gas wells. In May 2016, the EPA issued final methane emissions standards for the upstream oil and gas sector, including an extension of REC requirements to hydraulically fractured oil wells.

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 greenhouse gas 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 U.S. 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, heating oil or jet 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", or "RINs") to meet an EPA-specified Renewable Volume Obligation ("RVO").

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.

Pipeline Integrity

Recent high-profile oil spill events have led to a significant increase in exposure and expectation for environmental protection amongst the public, by governments and regulators and within industry.

Governments are setting new expectations for pipeline integrity management and spill response. The B.C. Government has outlined five minimum requirements that must be met for the province to consider the construction of heavy oil pipelines within its borders. Governments, through their regulators, have increased the number of inspections and reviews and in parallel have put in place a series of new expectations for stronger pipeline integrity and spill management. Saskatchewan introduced legislative amendments to its Pipelines Act in November 2016, including plans to licence flowlines in the province, establishing new inspection, investigation and compliance audit powers, providing requirements for financial assurance from operators for pipelines in high-risk locations such as water crossings and new obligations associated with environmental issues that could occur following pipeline abandonment.

Industry, as a group, has responded by developing and implementing best practice guidelines designed to deliver the new expectations.

On July 21, 2016, subsequent to the formation of HMLP, Husky discovered a leak on the 16TAN pipeline, part of the SGS, where it crosses the North Saskatchewan River. The pipeline was immediately isolated at the river crossing valves and spill response crews were dispatched. Approximately 225 cubic metres ("m^3") (plus or minus 10 percent), was released, with about 40 percent of that volume entering the river. As of December 31, 2016, shoreline cleanup operations accounted for 210 m^3. Total gross costs incurred in response to the spill were approximately $107 million, of which $88 million has been recovered through insurance proceeds. Both the spill costs and insurance recoveries have been incurred by HMLP.

An investigation undertaken by Husky and third-party experts concluded the pipeline break was caused by geotechnical activity. The break was a sudden, one-time event in a section of the pipe that had buckled due to the force of ground movement. Regulators are conducting a review of the incident.

While the investigation has concluded the SGS was designed and constructed in accordance with applicable standards and operators responded appropriately, Husky is implementing improvements to systems and operating procedures. A number of actions are being undertaken, including ensuring geotechnical risks are addressed and re-assessed over the life of a pipeline with mitigation and monitoring strategies, consistent with current procedures; applying additional safety loading factors to locations susceptible to potential geotechnical risk; review and consolidation of existing leak detection processes and procedures, including a defined time period for diagnostic analysis before proceeding to mandatory shutdown; and adjusting variables on the leak detection system to reduce the number of false alarms.

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. 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 bankruptcy court ruling, whereby the court found that receivers and trustees of AER licensees may selectively disclaim unprofitable assets (and their associated abandonment and reclamation obligations) under section 14.06 of the federal *Bankruptcy and Insolvency Act*, the AER and the Orphan Well Association are actively working on appropriate regulatory measures to mitigate the liability impact of licensee's abandonment, reclamation and remediation obligations from falling back to the industry.

Consequently, a condition of transferring existing AER licenses, approvals and permits, will require all 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 licensee 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 their threshold for providing a deposit. If a licensee's LMR is less than 1.0, meaning the liability is greater than the deemed assets, that licensee 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 Energy ruling, all licence transfer applications in Saskatchewan will be reviewed in detail, and ECON will consider all 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 is applying to intervene 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. All licence transfer applications in Saskatchewan will now 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 fluids are 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.

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.

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 ("CFA") which represents Canada's transportation fuels industry, the Company enhances its ability to identify and address potential policy and regulatory risks to Husky's 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.

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 GHG 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 heavy oil operations.

Husky pursues memberships with the following additional sustainability groups and industry associations:
Alberta Industrial Fire Protection Association, Allen Count Environmental Citizen's Advisory Committee, American Fuel & 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, 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, Cumulative Environmental Management Association, Devonian Aquifer Working Group - 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 CO_2 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, by taking steps to protect the environment or in delivering lasting benefits to the communities. More information can be found in the Husky Energy 2015 Community Report, which can be accessed under both the Social Responsibility and Environment sections of www.huskyenergy.com.

RISK FACTORS

The following summarizes what Husky believes to be the most significant risks relating to its operations that 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 in 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

Husky'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, NGLs and natural gas could adversely affect the value and quantity of Husky's oil and gas reserves. Husky'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 is limited and planned increases of North American heavy crude oil production may create the need for additional heavy oil refining and transportation capacity. Wider price differentials between heavier and lighter grades of crude oil could have a material adverse effect on Husky's results of operations and financial condition, reduce the value and quantities of Husky'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 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 and the availability of alternate sources of energy.

Husky's natural gas production is currently located in Western Canada and the Asia Pacific Region. Western Canada 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.

The natural gas Husky produces in the Asia Pacific Region is sold to specific buyers with long-term contracts. For the Liwan 3-1 gas field, a price profile has been fixed for five years and then will be linked to local benchmark pricing for the years following subject to a floor and ceiling. For the Liuhua 34-2 field, the price is fixed with a single escalation step during the contract delivery period. Natural gas price in North America is affected primarily by supply and demand, as well as by prices for alternative energy sources.

In certain instances, the Company uses derivative commodity instruments and futures contracts on commodity exchanges, including commodity put and call options under a short-term hedging program, 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 and business strategy. 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 NGLs 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

Husky'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 effected 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 Husky'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 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 and exchange rate fluctuations, unreasonable taxation and corrupt behaviour of public officials, joint venture partners or third-party representatives that could result in lost business opportunities for Husky. 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, which include the Company's ability to obtain the necessary environmental and regulatory approvals, changing government regulation and public expectation in relation to the impact on the environment, as well as the risks involved in commissioning and integration of new assets with existing facilities, can impact the economic feasibility of the Company's projects. Obtaining regulatory approvals can involve significant stakeholder consultation, environmental impact assessments and public hearings.These risks can result in, among other things, cost overruns, schedule delays and decreases in product markets. These risks can also impact the Company's safety and environmental performance, which could negatively affect 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, breach of contract, tax, bribery and employment matters, which could result in an unfavourable decision, including fines, sanctions, monetary damages 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 Husky's assets in which the Company has an ownership interest. This can reduce Husky's control and ability to manage risks. Husky 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 and Future Net Revenue 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. All such estimates are to some degree uncertain, and classifications of reserves are only attempts to define the degree of uncertainty involved. 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. For those reasons, the Company's estimates of the economically recoverable oil and gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom may differ substantially from actual results. 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 results of operations, financial condition, and ability to deliver on its growth business strategy.

Government Regulation

Given the scope and complexity of Husky'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 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 Husky's financial condition and results of operations 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 scope and complexity of changes in environmental regulation make it challenging to forecast the potential impact to Husky. Husky has made projections of the impact of scenarios involving certain potential laws and regulations relating to climate change. Husky engages in dialogue on proposed changes, both directly and through industry associations, with the goal of ensuring the Company's interests are recognized and Husky is sufficiently prepared to fully comply when new regulations come into force.

Husky 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 Husky's financial condition and results of operations through increased capital and operating costs. See "Industry Overview - Environmental Regulations".

Climate Change Regulation

The Company continues to monitor international and domestic efforts to address climate change, including international low carbon fuel standards and regulations and emerging regulations in the jurisdictions in which the Company operates.

The Alberta Climate Leadership Plan is expected to be implemented starting in 2017. This plan includes an economy wide carbon levy, rising to $30/ton in 2018 as well as a Carbon Competitiveness Regulation that will manage emissions at LFEs including the Ram River Gas Plant, Tucker Thermal Facility and Sunrise Energy Project. See "Industry Overview - Canadian Provincial Greenhouse Gas Regulations". The regulations under this plan are currently under development and will cover all of the Company's assets in Alberta. These regulations may materially adversely affect the Company's results of operations in the province.

Climate change regulations to be developed in Saskatchewan will have to meet equivalency standards with the Canadian federal government and may materially adversely affect the Company's results of operations in the province. See "Industry Overview - Canadian Provincial Greenhouse Gas Regulations".

The cost of compliance with British Columbia's $30 per ton carbon tax and the Renewable and Low Carbon Fuel Requirements Regulation may become material. Additionally, future regulations in support of British Columbia's commitment under its Climate Leadership Plan may materially adversely affect the Company's results of operations in British Columbia. See "Industry Overview - Canadian Provincial Greenhouse Gas Regulations".

The Manitoba Climate Change and Green Economy Action Plan implementation may materially adversely affect Husky's results of operations in Manitoba. See "Industry Overview - Canadian Provincial Greenhouse Gas Regulations". The Federal Government of Canada has announced its intention to commence developing a new federal climate change plan in consultation with the provinces. It is not clear how this new plan will be structured and what impacts it will have on Husky's results of operations. Climate change regulations may become more onerous over time as governments implement policies to further reduce GHG emissions. Although the impact of emerging regulations is uncertain, they could have a material adverse effect on the Company's financial condition and results of operations through increased capital and operating costs and change in demand for refined products.

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. Such legislation or regulation could require the Company's U.S. refining operations to significantly reduce emissions and/or purchase allowances, which may have a material adverse effect on the Company's financial condition and results of operations through increased capital and operating costs and change in demand for refined products.

The U.S. RFS program, through the U.S. 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 - 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% limit prescribed by most automobile warranties), the price and availability of RINs has been volatile.

The Company complies with the RFS program in the US 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

In certain instances, the Company uses derivative commodity instruments and futures contracts on commodity exchanges, including commodity put and call options under a short-term hedging program, to manage exposure to price volatility on a portion of its refined product, oil and gas production, and 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 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 on a monthly basis.

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 the majority 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 the availability 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 include 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 gain 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 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 Husky's ability to obtain short-term and long-term financing and the cost of such financing. Additionally, the ability of Husky to engage in ordinary course derivative or hedging transactions and maintain ordinary course contracts with customers and suppliers on acceptable terms 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. 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.

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 land and offshore drilling rigs, land and offshore geological and geophysical services, engineering and construction services and construction materials. These materials and services may not be available when required at reasonable prices.

Climatic Conditions

Extreme climatic conditions may have material adverse effects on 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, or disruptions to the operations of major customers or 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. All of these could potentially cause material adverse effects on the Company's results of operations and financial condition.

The Company operates in some of the harshest environments in the world, including offshore in the Atlantic Region. Climate change may increase 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 Newfoundland and Labrador may threaten offshore oil production facilities, causing 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 Region business unit 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 Canada, the Coast Guard and Canadian Ice Service. Regular ice surveillance flights commence in February and continue until the threat has abated. In addition, Atlantic Region 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.

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 by third parties. 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 Husky's strategy is dependent on ensuring our 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 results of operations.

HUSKY EMPLOYEES

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

As at December 31,		
2016	2015	2014
5,150	5,552	5,774

DIVIDENDS

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:

	2016	2015	2014
Dividends per Common Share	$ —	$ 0.90	$ 1.20
Dividends per Series 1 Preferred Share	$ 0.73	$ 1.11	$ 1.11
Dividends per Series 2 Preferred Share	$ 0.42	$ —	$ —
Dividends per Series 3 Preferred Share	$ 1.13	$ 1.19	$ —
Dividends per Series 5 Preferred Share	$ 1.13	$ 0.90	$ —
Dividends per Series 7 Preferred Share	$ 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 shares dividends declared in the year 2016 (year ended December 31, 2015 - $1,181 million).

Husky's dividend policy will continue to be reviewed and there can be no assurance that further dividends will be declared or the amount of any future dividend.

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 5-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).

Liquidity Summary

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 ability of Husky 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 ten 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 ten 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, 2016:

	High	Low	Volume (000's)
January	14.72	11.34	38,143
February	14.76	11.50	35,638
March	17.09	15.02	43,899
April	18.10	14.63	38,707
May	15.95	14.35	33,598
June	16.90	14.45	29,757
July	16.14	15.01	16,719
August	17.22	15.03	16,204
September	16.49	15.06	18,871
October	16.93	14.20	25,726
November	15.88	13.92	23,410
December	17.35	15.70	38,263

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, 2016:

	High	Low	Volume (000's)
January	13.37	8.18	319
February	8.95	7.80	546
March	10.81	8.45	727
April	11.41	10.06	332
May	11.79	10.99	495
June	12.51	11.02	405
July	12.04	11.09	377
August	12.76	11.83	167
September	12.26	11.74	203
October	12.35	11.62	295
November	12.79	11.60	314
December	13.45	12.12	562

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, 2016:

	High	**Low**	**Volume (000's)**
April	10.51	9.00	28
May	10.94	10.03	26
June	11.54	10.20	71
July	11.50	10.10	28
August	11.90	10.96	23
September	11.98	11.04	33
October	11.75	11.03	29
November	12.25	11.36	26
December	13.15	11.56	42

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, 2016:

	High	**Low**	**Volume (000's)**
January	18.41	12.99	340
February	15.37	13.02	181
March	17.00	13.86	150
April	18.20	16.40	152
May	18.00	16.94	140
June	19.24	16.88	198
July	18.32	17.40	139
August	19.91	18.20	95
September	19.62	19.04	117
October	19.94	19.00	267
November	20.48	19.30	256
December	21.83	20.24	224

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, 2016:

	High	**Low**	**Volume (000's)**
January	19.38	13.50	303
February	16.24	14.29	251
March	18.90	15.68	234
April	20.27	18.37	173
May	20.10	19.02	137
June	20.97	18.66	133
July	19.91	19.02	96
August	21.39	19.85	105
September	21.31	20.62	146
October	22.02	20.90	202
November	22.23	20.86	240
December	22.99	21.46	249

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, 2016:

	High	**Low**	**Volume (000's)**
January	19.36	13.61	215
February	16.40	14.44	151
March	19.07	15.77	101
April	20.23	18.24	102
May	20.15	18.50	82
June	20.83	18.47	190
July	20.11	19.20	220
August	21.99	20.06	191
September	21.41	20.99	91
October	21.98	20.85	109
November	22.44	21.24	201
December	23.09	21.39	215

DIRECTORS AND OFFICERS

The following are the names and residences of the directors and 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. Each director will hold office until the Company's next annual meeting or until his or her successor is appointed or elected.

Directors

Name & Residence	Office or Position	Principal Occupation During Past Five Years
Li, Victor T.K. Hong Kong Special Administrative Region	Co-Chair Director of Husky 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 Cheung Kong Property Holdings Limited. He is also the Chairman and Executive Director of 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 a member of the Commission on Strategic Development of the Hong Kong Special Administrative Region and Vice Chairman of the Hong Kong General Chamber of Commerce. Mr. Li is the Honorary Consul of Barbados in Hong Kong. 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 and Chair of the Compensation Committee Director of Husky 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 Cheung Kong Infrastructure Holdings Limited and an Alternate Director to a Director of Hutchison Telecommunications Hong Kong 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	Mr. Bradley is a Director of Broadlea Group Ltd., Senior Consultant, ICAP (Asia Pacific) Ltd. and a Director of Swire Properties Ltd. (Hong Kong).

	Director of Husky since July 2010	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 Portugal	Director of Husky 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 co-founding 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	Mr. Glynn is a Director of Public Sector Pension Investment Board (PSP Investments), Sun Life Financial Inc., Sun Life Assurance Company of Canada and Chair of UBC Investment Management Trust Inc.
	Director of Husky since August 2000	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 of Husky since August 2000	Ms. Koh is Finance Director of Harbour Plaza Hotel Management (International) Ltd. (a hotel management company). 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 Cheung Kong Infrastructure Holdings Limited. Mrs. Kwok is also a Director of the Li Ka Shing (Canada) Foundation.
	Director of Husky 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 of Husky since August 2000	Mr. Kwok is a Director of the CTBC Bank of Canada and Element Lifestyle Retirement Inc.
		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 of Husky 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 of Husky since July 2010	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.

		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 of Husky 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 BASc in Mechanical Engineering from the University of British Columbia and a MSc in Management (Sloan Fellow) from Stanford University. Mr. Peabody is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA).
Russel, Colin S. Gloucestershire, United Kingdom	Member of the Audit Committee and the Health, Safety and Environment Committee Director of Husky 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 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 Corporate Governance Committee and the Health, Safety and Environment Committee	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.
	Director of Husky since August 2000	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 and Chair of the Audit Committee Director of Husky 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 of Husky 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 a Non-Executive Chairman of TOM Group Limited, an Executive Director of 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

Name and Residence	Office or Position	Principal Occupation During Past Five Years
Jonathan M. McKenzie 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.
Girgulis, James D. Alberta, Canada	Senior Vice President, General Counsel & Secretary	Vice President, Legal & Corporate Secretary of Husky since August 2000. Senior Vice President, General Counsel & Secretary since April 2012.

As at February 15, 2017, the directors and officers of Husky, as a group, beneficially owned or controlled or directed, directly or indirectly, 889,740 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

The members of Husky's Audit Committee (the "Committee") are William Shurniak (Chair), Stephen E. Bradley, Colin S. Russel, Frederick S.H. Ma and George C. Magnus. 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).

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.

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.

Husky's Audit Committee Mandate is attached hereto as Schedule "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)	**2016**	**2015**
Audit Fees	3,858	3,446
Audit-related Fees	158	615
Tax Fees	350	69
	4,366	**4,130**

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 2016.

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 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, 2016 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 will be contained in Husky's Management Information Circular prepared in connection with the annual meeting of shareholders to be 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 most recently completed fiscal year ended December 31, 2016.

Additional information relating to Husky Energy Inc. is available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

READER ADVISORIES

Special Note Regarding 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 U.S. Securities Exchange Act of 1934, as amended, and Section 27A of the U.S. 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", "estimated", "intend", "plan", "projection", "could", "may", "would", "aim", "vision", "goals", "objective", "target", "schedules" 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 expected expenditures in 2017 on environmental site closure activities; 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, 2016; the Company’s 2017 production estimates broken down by product type and location; and anticipated effects of and cost of compliance with certain future or proposed laws and regulations on the Company's operations;
- with respect to the Company's Asia Pacific Region: anticipated volumes of peak combined net sales volumes of gas and NGL from the BD, MDA, MBH and MDK fields; anticipated timing of signing the floating production vessel lease contract for, and first production at, the MDA, MBH, and MDK gas fields; anticipated timing of exploration and drilling plans at Block 15/33; anticipated timing of acquisition of seismic surveying data at the Taiwan exploration block; and anticipated timing of first production and reaching full gas sales rates from the BD field;
- with respect to the Company's Oil Sands properties: anticipated range of daily production volumes from the Company's Sunrise Energy Project for 2017;
- with respect to the Company's Heavy Oil properties: the Company’s strategic plans for its Heavy Oil Thermal production and CHOPS production; capacity at Edam West; anticipated timing of first production from, and nameplate capacities of, the Company's Rush Lake 2, Dee Valley, Spruce Lake Central, and Spruce Lake North heavy oil thermal projects; estimated daily production from Tucker Lake Thermal Project by 2019; anticipated timing and extent of evaluation drilling at McMullen Willow Creek Thermal Development, and anticipated timing of associated AER application; and anticipated timing of first production from, and nameplate capacity of, the Phase I Plant at McMullen Willow Creek Thermal Development and the conceptual development plan through to 2040;
- with respect to the Company's Western Canadian oil and gas resource plays: growth strategies and development opportunities; the Company’s 2017 drilling plans for the Foothills operations; anticipated impact on sales capacity from, and timing of completion of, the Rainbow Lake processing plant modifications; and plan not to pursue any activity in the Northwest Territories in 2017;
- with respect to the Company’s Upstream Infrastructure and Marketing operating segment: planned expansion of HMLP's gathering system network and Hardisty terminal, and anticipated benefits of such expansion; and
- with respect to the Company's Downstream operating segment: anticipated timing of completion, outcome, and benefits of the reliability and profitability improvement projects at the Company's Lima Refinery; plans to process bitumen from the Sunrise Energy Project; the Company's 2017 plans for its asphalt distribution network, including increasing asphalt modification capacity, expanding U.S. retail sales, and marketing residual productions; anticipated benefits of expanded asphalt processing capacity; and anticipated timing of consolidation of the Company’s and Imperial Oil’s truck transport network.

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, regulators and other sources. 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 Asia Pacific Region, Atlantic Region, Oil Sands properties, Heavy Oil properties, Western Canadian oil and gas resource plays and Infrastructure and Marketing operations: 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 of 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 of 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, 2016; 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 Asia Pacific Region, Atlantic Region, Oil Sands properties, Heavy Oil properties, Western Canadian oil and gas resource plays and the Infrastructure and Marketing operations: 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, license 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, 2016 available on SEDAR at www.sedar.com and on EDGAR at www.sec.gov.

In the discussions above, the Company has categorized 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 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.

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. 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 its assessment of the future considering all information then available.

Non-GAAP Measures

This document contains the term “operating netback”, which is a common non-GAAP metric used in the oil and gas industry and is considered to be useful as a complementary measure in assessing the Company’s financial performance, efficiency and liquidity. This measurement assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. There are no comparable measures to this non-GAAP measure in accordance with IFRS, and it is therefore unlikely to be comparable to similar measures presented by other issuers. The operating netback was determined as gross revenue less royalties, production and operating expenses, and transportation expenses on a per unit basis.

Disclosure of Oil and Gas Information

Unless otherwise stated, reserve estimates in this document, 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, 2016 and represent Husky's share. Unless otherwise noted, historical production numbers given represent Husky’s share.

The Company uses the term reserve replacement ratio, which is consistent with other oil and gas companies’ disclosures. Reserve 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 reserve replacement ratio measures the amount of reserves added to a company's reserve base during a given period relative to the amount of oil and gas produced during that same period. A company's reserve replacement ratio must be at least 100 percent for the company to maintain its reserves. The reserve replacement ratio only measures the amount of reserves added to a company's reserve base during a given period.

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 SEC.

All currency is expressed in Canadian dollars unless otherwise stated.

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, 2016. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2016, 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, 2016, 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, 2016	Canada	$17,525 million
		China	$4,322 million
		Indonesia	$833 million
			$22,680 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, 2017

Husky Energy Inc.

Report of Management and Directors on Oil and Gas Disclosure

Management of Husky Energy Inc. ("Husky") are 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, 2016, 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 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 National Instrument 51-101 "Standards of Disclosure for Oil and Gas Disclosure" 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 24, 2017
Robert J. Peabody *President & Chief Executive Officer*	
/s/ James D. Girgulis	February 24, 2017
James D. Girgulis *Senior Vice President, General Counsel & Secretary*	
/s/ William Shurniak	February 24, 2017
William Shurniak *Director*	
/s/ Frederick S.H. Ma	February 24, 2017
Frederick S.H. Ma *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 2016 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, 2016. 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 (COGEH) 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, 2016		
	Working Interest Before Royalty Company Share of Remaining Reserves (mmboe)	**Company Share of Net Present Value Before Income Tax (MM$) @ 10%**
Total Proved	1,224	13,996
Total Proved Plus Probable	2,815	22,680

Sincerely,

Sproule Associates Limited

/s/ Cameron P. Six, P. Eng.
Cameron P. Six, P. Eng.
Vice-President Engineering, Chief Engineer and Director
Calgary, Alberta
January 31, 2017