ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2019

February 27, 2020

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NOTE TO READER

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

Unless otherwise indicated, the information contained in this AIF is presented as at or for the year ended December 31, 2019, and all financial information included and incorporated by reference in this AIF is determined using International Financial Reporting Standards ("**IFRS**"), as issued by the International Accounting Standards Board.

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

See also "Reader Advisories" on page 81 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
bbl/day	barrel per calendar day
bbls/day	barrels per calendar day
bcf	billion cubic feet
bcf/day	billion cubic feet per calendar day
boe	barrels of oil equivalent
boe/day	barrels of oil equivalent per calendar day
GJ	gigajoule
kt	kilotonne
long ton/day	imperial measurement of a metric tonne per calendar day
m3	cubic metres
mbbls	thousand barrels
mbbls/day	thousand barrels per calendar day
mboe	thousand barrels of oil equivalent
mboe/day	thousand barrels of oil equivalent per calendar day
mcf	thousand cubic feet
mmbbls	million barrels
mmboe	million barrels of oil equivalent
mmbtu	million British thermal units
mmcf	million cubic feet
mmcf/day	million cubic feet per calendar day
tcf	trillion cubic feet
tCO_2e	tonnes of carbon dioxide equivalent

abandonment and reclamation costs
All costs associated with the process of restoring the Company'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.

Asphalt Refinery
The asphalt refinery owned by the Company and located in Lloydminster, Alberta.

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

bitumen
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.

Board
The Board of Directors of the Company.

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

CHOPS
Cold heavy oil production with sand.

CO_2e
Carbon dioxide equivalent.

conventional natural gas
Natural gas that has been generated elsewhere and has migrated as a result of hydrodynamic forces and is trapped in discrete accumulations by seals that may be formed by localized structural, depositional or erosional geological features.

C-NLOPB
Canada-Newfoundland Offshore Petroleum Board

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

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

feedstock
Raw materials which are processed into petroleum products.

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

FPSO
Floating production, storage and offloading vessel.

GAAP
Generally accepted accounting principles, consistently applied.

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

gross reserves and gross production
A company's working interest share of reserves or production, as the context requires, before deduction of royalties.

GSA
Gas sales agreement.

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.

HMLP
Husky Midstream Limited Partnership.

HS&E
Health, safety and environment.

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

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

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

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

natural gas
A naturally occurring hydrocarbon gas and other gases.

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

net revenue
Gross revenue less royalties.

NL
Newfoundland and Labrador.

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
Represents, as it relates to the Company's operations in Indonesia, a development plan on one or more oil and gas fields in an integrated and optimal plan for the production of hydrocarbon reserves considering technical, economical and environmental aspects. An initial Plan of Development in a development area needs both SKK Migas and the Minister of Energy and Mineral Resources approvals. Subsequent Plans of Development in the same development area only need SKK Migas approval.

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

Scope 1 emissions
Direct emissions from sources that are owned or controlled by the Company, as prescribed by the U.S. Environmental Protection Agency.

Scope 2 emissions
Indirect emissions from sources that are owned or controlled by the Company, as prescribed by the U.S. Environmental Protection Agency.

SEC
United States Securities and Exchange Commission.

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

seismic survey
A method by which the physical attributes in the outer rock shell of the earth are determined by measuring, with a seismograph, the rate of transmission of shock waves through the various rock formations.

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

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

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

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

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

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

sulphur
An element that occurs in natural gas and petroleum.

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

synthetic oil
A mixture of hydrocarbons derived by upgrading heavy crude oils, including bitumen, through a process that reduces the carbon content and increases the hydrogen content.

thermal
Use of steam injection into the reservoir in order to enable the heavy oil and bitumen to flow to the well bore.

turnaround
Performance of plant or facility maintenance.

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

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

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

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

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

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

2018 U.S. Shelf Prospectus and Registration Statement
The universal short form base shelf prospectus filed by the Company on January 29, 2018 with the Alberta Securities Commission and the related U.S. registration statement (containing such prospectus) filed with the SEC that became effective on January 30, 2018.

EXCHANGE RATE INFORMATION

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

	Year ended December 31,		
Exchange Rate Information *(Cdn$ per US$)*	**2019**	2018	2017
Year-end[(1)]	**1.297**	1.365	1.252
Low	**1.297**	1.228	1.213
High	**1.359**	1.365	1.374
Average	**1.327**	1.296	1.298

(1) The year-end exchange rates were quoted by the Thomson Reuters WM/R for the noon rate 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

Incorporation and Organization

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

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

Intercorporate Relationships

The following table lists Husky's significant subsidiaries and jointly-controlled entities and their respective places of incorporation, continuance or organization, as the case may be, as at December 31, 2019. All of the entities listed below, except as otherwise indicated, are 100% beneficially owned, or controlled or directed, directly or indirectly, by Husky.

Significant Subsidiaries and Joint Operations[(1)]	Jurisdiction
Husky Oil Operations Limited	Alberta
Husky Energy International Corporation	Alberta
Lima Refining Company	Delaware
Husky Marketing and Supply Company	Delaware
Husky Oil Limited Partnership	Alberta
Husky Terra Nova Partnership[(2)]	Alberta
Husky Downstream General Partnership[(2)]	Alberta
Husky Energy Marketing Partnership	Alberta
Sunrise Oil Sands Partnership (50%)	Alberta
BP-Husky Refining LLC (50%)	Delaware

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

(2) Dissolved effective January 1, 2020, and assets were transferred to 2188787 Alberta ULC, a wholly-owned subsidiary of Husky.

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.

2017

On March 10, 2017, the Company issued $750 million of 3.60% notes due March 10, 2027 by way of a prospectus supplement dated March 7, 2017 to its base shelf prospectus.

On April 13, 2017, the Company announced that it had signed a PSC for Block 16/25 in the Pearl River Mouth Basin in the South China Sea. Under the PSC, Husky has an obligation to drill two exploration wells within the first three years.

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

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

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

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

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

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

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

On November 8, 2017, the Company completed the purchase of the Superior Refinery from Calumet Specialty Products Partners, L.P. for $670 million (US$527 million). The acquisition included the Superior Refinery's associated logistics assets, including two asphalt terminals, 3.6 mmbbls of crude and product storage and a fuels and asphalt marketing business. See "Description of Husky's Business - Integrated Corridor - U.S. Refining and Marketing - Superior Refinery".

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

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

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

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

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

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

2018

On January 17, 2018, the Company announced that it would begin taking steps to suspend operations of the *SeaRose* FPSO and associated production facilities offshore NL to comply with an order received from the C-NLOPB related to an iceberg management incident that occurred in March 2017.

On January 26, 2018, the Company announced that the C-NLOPB had lifted the notice to suspend operations of the *SeaRose* FPSO and associated facilities and that the Company would resume operations.

On March 1, 2018, the Company announced the establishment of a quarterly cash dividend of $0.075 per common share.

On April 26, 2018, a fire occurred at the Superior Refinery and operations were suspended.

On May 18, 2018, the Company announced that it had drilled a successful exploration well on Block 15/33 in the South China Sea, signed two PSCs for Block 22/11 and Block 23/07 in the Beibu Gulf area of the South China Sea and made a discovery at the White Rose A-24 exploration well offshore NL.

On July 26, 2018, the Company announced that the Board had approved an increase in the quarterly cash dividend to $0.125 per common share.

During the third quarter of 2018, the BD Project achieved total daily sales targets of 100 mmcf/day of conventional natural gas (40 mmcf/day Husky working interest) and 6,000 bbls/day of associated NGL (2,400 bbls/day Husky working interest).

On October 2, 2018, the Company announced that it had commenced an unsolicited offer to acquire all of the outstanding common shares of MEG Energy Corp. ("**MEG**").

In October 2018, the Tucker Thermal Project reached nameplate capacity of 30,000 bbls/day.

Also in October 2018, the Rush Lake 2 thermal project achieved first production, with nameplate capacity of 10,000 bbls/day achieved in November 2018.

In November 2018, the Company shut in oil production at the White Rose field due to operational safety concerns resulting from severe weather and an oil release on November 16.

Also in November 2018, the Spruce Lake East thermal project in Saskatchewan was sanctioned.

In December 2018, the Sunrise Energy Project reached its nameplate capacity of 60,000 bbls/day (30,000 bbls/day Husky working interest).

2019

On January 8, 2019, the Company announced that it would be undertaking a strategic review and potentially selling its Canadian Retail and Commercial Fuels Network and the Prince George Refinery.

On January 16, 2019, the Company's unsolicited offer to acquire all of the outstanding common shares of MEG expired with the minimum tender condition not having been met. The Company did not extend the offer due to a lack of support from the MEG board of directors and MEG shareholders.

On March 15, 2019, the Company issued US$750 million of 4.400% notes maturing on April 15, 2029 by way of a prospectus supplement dated March 13, 2019 to the 2018 U.S. Shelf Prospectus and Registration Statement.

On January 30, 2019, partial production resumed at the White Rose field following the shut-in of production announced in November 2018.

In the first quarter of 2019, regulatory approval was received for the Spruce Lake East thermal project.

On June 12, 2019, the Company entered guilty pleas on federal and provincial charges related to a 2016 oil spill in Saskatchewan and agreed to pay fines totaling $3.82 million.

On August 16, 2019, the Company announced that it would resume full production at the White Rose field.

On August 26, 2019, the Company announced that it had commenced production at its 10,000 barrel-per-day Dee Valley thermal project in Saskatchewan.

On September 30, 2019, the Company announced that it had received the required permit approvals to begin construction activities at the Superior Refinery following the April 2018 fire, and that the rebuild would take place over the following two years.

On November 1, 2019, the Company announced the closing of the sale of the Prince George Refinery to Tidewater Midstream and Infrastructure Ltd. ("**Tidewater**") for $215 million in cash plus a closing adjustment of approximately $53.5 million.

On December 20, 2019, production operations on the *Terra Nova* FPSO were safely shut-in in response to a C-NLOPB order citing insufficient redundancy of fire water pumps. See "Description of Husky's Business - Offshore - Atlantic - Terra Nova Field".

DESCRIPTION OF HUSKY'S BUSINESS

Overview

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

Management has identified segments for the Company's business based on differences in products, services and management responsibility. For the year ended December 31, 2019, the Company's business was conducted predominantly through two major business segments: Upstream and Downstream.

Upstream operations include exploration for, and development and production of, crude oil, bitumen, conventional natural gas and NGL ("**Exploration and Production**") and marketing of the Company's and other producers' crude oil, conventional natural gas, NGL, sulphur and petroleum coke, pipeline transportation, the blending of crude oil and conventional natural gas, and storage of crude oil, diluent and conventional 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 China and Indonesia ("**Asia Pacific**") and offshore the east coast of Canada ("**Atlantic**") (Asia Pacific and Atlantic collectively, "**Offshore**").

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

Effective January 1, 2020, the Company's businesses were reorganized under two new business segments: (i) an integrated Canada-U.S. Upstream and Downstream corridor ("**Integrated Corridor**"); and (ii) production located offshore the east coast of Canada ("Atlantic") and offshore China and Indonesia ("**Asia Pacific**" and collectively with Atlantic, "**Offshore**"). The Company will no longer operate under Upstream and Downstream business segments.

Integrated Corridor

The Company's business in the Integrated Corridor includes: crude oil, bitumen, conventional natural gas, NGL and ethanol production from Western Canada; marketing and transportation of the Company's and other producers' production; the Upgrader and Asphalt Refinery; Husky Midstream Limited Partnership (35% working interest and operatorship); the Lima Refinery, the BP-Husky Toledo Refinery (50% working interest) and the Superior Refinery in the U.S. Midwest; and the marketing of refined petroleum products including gasoline, diesel and ethanol blended fuels through petroleum outlets. Conventional natural gas production from the Western Canada portfolio is closely aligned with the Company's energy requirements for refining and thermal bitumen production and acts as a natural hedge.

Offshore

The Company's Offshore business includes operations, development and exploration in Asia Pacific and Atlantic.

Corporate Strategy

The Company's business strategy is to generate returns from investing in a deep portfolio of projects and other opportunities across the Integrated Corridor and Offshore businesses. These investments are intended to provide for increasing margins, funds from operations and earnings. A strong balance sheet, deep physical integration and largely fixed price contracts in Asia Pacific provide resilience to market volatility while preserving upside exposure to rising commodity prices.

Integrated Corridor

Thermal and Non-Thermal Developments

Heavy Oil and Bitumen

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. The majority of the Company's operations are 100% working interest. The Company's operations are supported by a network of facilities and pipelines that transport heavy crude oil and bitumen from the field locations to the Asphalt Refinery, the Upgrader and the Company's other assets in the Integrated Corridor business segment, thus providing full integration.

Production of heavy crude oil and bitumen from the Lloydminster area uses a variety of technologies, including SAGD, CHOPS, horizontal wells, waterflooded fields and non-thermal EOR.

Lloydminster Thermal Projects

Lloydminster bitumen production consists of 10 thermal plants located in the Lloydminster region of Saskatchewan: Bolney/Celtic, Dee Valley, Edam East, Edam West, Paradise Hill, Pikes Peak South, Rush Lake 1 & 2, Sandall and Vawn. Each plant has a number of production pads and utilizes SAGD technology. Production in 2019 from Lloydminster thermal projects averaged 80,500 bbls/day. Saskatchewan thermal production is not impacted by Alberta government-mandated production curtailment.

The Company is phasing execution of its long-life thermal projects to optimize capital efficiency and project execution. In 2018, the Company completed two land deals to create two thermal hubs, one at Spruce Lake and one at Dee Valley. This has resulted in the acceleration of the Spruce Lake East project. The Edam Central project is now expected to be completed in 2022.

The following table shows major projects and their status as at December 31, 2019:

Project Name	Nameplate Capacity (bbls/day)	Expected Project Production Date	Project Status
Dee Valley	10,000	On production August 2019	First steam was achieved on June 30, 2019, with first oil on August 24, 2019. Reached nameplate capacity on September 30, 2019.
Spruce Lake Central[(1)]	10,000	Mid-Year 2020	Central Processing Facility ("**CPF**") construction is complete and module setting on well pads has begun. Overall project is 90% complete.
Spruce Lake North	10,000	Around the end of 2020	CPF fabrication and module setting is complete. The overall project is 50% complete.
Spruce Lake East	10,000	Around the end of 2021	Regulatory approvals have been received, and lease construction is complete. Procurement and fabrication programs are in progress.
Edam Central	10,000	2022	Regulatory approvals have been received.
Dee Valley 2	10,000	2023	Project sanctioned in November 2019, and regulatory approvals have been received.

(1) *Previously expected to start production by the second half of 2020.*

In February 2019, the Pike's Peak thermal bitumen plant was closed down as it reached the end of its useful life. The plant achieved first production in September 1981 and produced 78 mmbbls over its useful life.

Tucker Thermal Project

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

Work to debottleneck the CPF and field was completed in 2018. Subsequently, production ramped up and nameplate capacity of 30,000 bbls/day was achieved in October 2018. Total annual production in 2019 averaged 23,700 bbls/day and was impacted by the government-mandated production quotas in Alberta. The Company plans to drill two new sustainment pads in 2020/21.

A major plant turnaround is scheduled for the CPF and field in the fourth quarter of 2020.

Cold and EOR

Production in Cold and EOR consists of a combination of production technologies, including CHOPS and horizontal wells and EOR projects.

In 2018, the Company sanctioned a full field polymer injection project at Aberfeldy, and injection began in 2019.

During 2019, the Company operated three carbon dioxide ("**CO_2**") injection EOR pilot projects and a CO_2 capture and liquefaction plant at the Lloydminster Ethanol Plant. The liquefied CO_2 is used in the ongoing EOR piloting program. The Company is also piloting several types of CO_2 capture technology at its Pikes Peak South facility in Saskatchewan.

Total annual production in 2019 averaged 34,400 bbls/day and was also impacted by the government-mandated production quotas in Alberta.

Sunrise Energy Project

On March 31, 2008, Husky and BP Corporation North America Inc. ("BP") completed a transaction that created an integrated North American oil sands and refining businesses. The businesses are comprised of a 50/50 partnership to develop the Sunrise Energy Project, operated by Husky, and a 50/50 limited liability company for the BP-Husky Toledo Refinery, operated by BP. The Sunrise Energy Project is a SAGD oil sands project located in the Athabasca region of northern Alberta. During the fourth quarter of 2018 the project reached its nameplate capacity of 60,000 bbls/day.

At the end of 2019, there were 81 producing well pairs. Five well pairs and six infills have been drilled and are ready for production once government-mandated production quotas are lifted. Total annual production in 2019 averaged 49,200 bbls/day (24,600 bbls/day Husky working interest), and was impacted by the government-mandated production quotas in Alberta and the completion of a planned turnaround on Plant 1A. The turnaround on Plant 1B is scheduled for the second quarter of 2020.

Western Canada

Northern Operations

The Company's Northern operations are located primarily in northwest Alberta. Production in 2019 consisted of approximately 1,300 bbls/day of light crude oil, 6,600 bbls/day of NGL and 172.8 mmcf/day of conventional natural gas. The area is heavily weighted towards conventional natural gas production (approximately 79%). Primary areas of operation include Edson and Grande Prairie, where operations are centered on liquids-rich gas resources.

Edson operations are located primarily in west-central Alberta and consist of the Ansell and Galloway areas. The Ansell conventional natural gas resource play is located in the deep basin Cretaceous formation, with the Company holding an average 95% working interest in approximately 177 net sections of contiguous lands. The Company has been actively developing the Spirit River formation since 2012 using multi-stage fractured horizontal wells. Production from the Ansell and Galloway areas has doubled since 2012 and in 2019 averaged 2,200 bbls/day of NGL and 112.6 mmcf/day of conventional natural gas. In 2019, the Company drilled two wells and completed six wells, while also participating in one non-operated well. In November 2019, the Company consolidated the majority of its Ansell production to the new HMGP Corser gas plant and shut-in some older area facilities to reduce costs.

Grande Prairie operations are located primarily in northwest Alberta and consist primarily of the Wembley, Kakwa, Wapiti and Karr areas. Production from Grande Prairie in 2019 averaged 1,300 bbls/day of light crude oil, 4,400 bbls/day of NGL and 60.2 mmcf/day of conventional natural gas. A drilling program targeting the oil and liquids-rich conventional natural gas Montney formation in the Wembley and Karr areas continued with five wells drilled in 2019 and nine wells completed. Six of these wells were brought on production in the fourth quarter of 2019, averaging 500 boe/day in 2019, with the remaining two beginning production in early 2020. At Wembley, the Company has a processing agreement at the Tidewater Pipestone Gas Plant and a transportation agreement with HMGP for a pipeline connection between the Company's 13-26 pad and the Tidewater take point. The Kakwa Spirit River liquids-rich conventional natural gas resource play averaged 50 bbls/day of light crude oil, 2,600 bbls/day of NGL and 41.0 mmcf/day of conventional natural gas in 2019. During the year, the Company drilled three wells and completed six wells in Kakwa. Development is focused on the Cardium oil play in the Wapiti area south of the city of Grand Prairie, Alberta, utilizing horizontal drilling and multi-stage fracturing technology to unlock crude oil reserves. During 2019, production from the Cardium play averaged 2,400 boe/day.

Southern Operations

The Company's Southern operations are primarily located in central and southern Alberta. As at December 31, 2019, the Company operated one crude oil and four conventional natural gas facilities with approximately 600 active wells throughout the area. Production in 2019 averaged 1,100 bbls/day of light crude oil, 2,100 bbls/day of NGL and 36.0 mmcf/day of conventional natural gas. In September 2019, the Company signed a Purchase and Sale Agreement to divest the assets in the Hussar area. In 2019, production from these assets averaged 300 bbls/day of light crude oil, 250 bbls/day of NGL and 7.5 mmcf/day of conventional natural gas. The sale was completed on February 11, 2020.

In 2019, the Company continued to participate in an eight-well non-operated Viking program in the North Blackstone area. During the year, four wells were drilled and eight wells were completed and brought on production by the end of 2019. During 2019, production from this program averaged 1,400 boe/day.

Rainbow Lake Development

Rainbow Lake, located approximately 900 kilometres northwest of Edmonton, Alberta, is the site of the Company's largest light crude oil production operation in Western Canada. Production during 2019 from the Rainbow Lake assets averaged 4,700 bbls/day of light crude oil, 4,000 bbls/day of NGL and 72.9 mmcf/day of conventional natural gas. The Company continued a Muskeg oil appraisal program in 2019 with one well drilled and 11 wells completed during the year. During the year, the Company successfully completed a 21-day turnaround at the Rainbow Lake facility, on time and without any safety incidents.

The Company holds a 50% 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 acquired two ELs in 2011 in the Northwest Territories at the Slater River Canol shale play, which were consolidated as one EL in 2015 and cover 483,000 gross acres (466,000 net acres). Two pilot wells were drilled and suspended in 2012 which satisfied the requirements to extend the term of both the ELs to their full nine-year term. In 2016, the Company was awarded a Significant Discovery Declaration on 545 sections (150,000 hectares) of land within the ELs north of the Gambill Fault, and granted separately a Significant Discovery License over five sections of land south of the Gambill Fault. Abandonment work on the two pilot wells and 12 water monitoring wells in addition to reclamation of well sites and surplus infrastructure commenced in the fourth quarter of 2018 and carried through the 2019 winter season. In addition, summer work in 2019 included continued reclamation work as well as maintenance on the existing infrastructure that will remain in place to service the Significant Discovery Declaration area.

Infrastructure and Marketing

Overview

The Company is engaged in the marketing of both its own and other producers' crude oil, natural gas, NGL, asphalt, sulphur and petroleum coke production. The sale and transportation of the Company's production and third-party commodity trading volumes are managed 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 production and/or third-party commodity trading volumes from Canada to the U.S. market.

Husky Midstream Limited Partnership

HMLP was created in July 2016 with the sale of selected pipeline gathering systems in Alberta and Saskatchewan and the Lloydminster and Hardisty terminals. CKI Infrastructure Holdings Limited owns 16.25%, Power Assets Holdings Limited owns 48.75% and Husky owns 35% of HMLP and is the operator. HMLP has approximately 2,200 kilometres of pipeline in the Lloydminster region, 4.1 million barrels of storage capacity at Hardisty and Lloydminster and other ancillary assets. The Lloydminster Terminal, with a total storage capacity of 1.0 million barrels, serves as a hub for the gathering systems. The pipeline system transports blended heavy crude oil to Lloydminster, providing feedstock for the Upgrader and for the Asphalt Refinery, and to Hardisty where the system connects to downstream pipelines accessing markets across Canada and the United States. Blended heavy crude oil and bitumen from the field and synthetic crude oil from the upgrading operations are transported south to Hardisty, Alberta to a connection with the major export trunk pipelines. The Hardisty Terminal, with a total storage capacity of 3.4 million barrels, acts as the exclusive blending hub for Western Canada Select ("**WCS**"), the largest heavy oil benchmark pricing point in North America.

HMLP has a separate Board of Directors from Husky and independent financing that supports both significant growth projects that are under construction and planned future expansions. Approximately $700 million in growth projects are underway. HMLP is in the process of diversifying its operations beyond the Lloydminster and Hardisty area and has completed construction of the Ansell Corser Gas Plant, which added 120 mmcf/day of processing capacity in the fourth quarter of 2019.

A major pipeline project is underway in Saskatchewan to provide transportation for the anticipated increase in the Company's bitumen production. The Hardisty terminal is also expanding to provide additional pipeline connectivity and crude oil storage for customers. The assets will play an integral and valuable role in the successful transportation of heavy oil and bitumen production to end markets by providing connections to the Upgrader and to the 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 U.S. Midwest. This strategy was further supported through the acquisition of the Lima Refinery in 2007, which enabled the Company's Canadian synthetic and bitumen production, along with additional third-party crude and other feedstocks, 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 Keystone pipeline commitment, the Lima Refinery is able to access a significant amount of Canadian crude oil as part of its crude feedstock requirements. The Keystone pipeline has enabled the Company to transport crude oil through interconnecting pipeline systems to the Lima Refinery and/or sell it into the Cushing, Oklahoma market.

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

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

In December of 2018, the Government of Alberta imposed an oil production curtailment order in Alberta. This reduced the economic motivation to export crude by rail or develop longer term market access strategies.

Natural Gas Storage Facilities

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

Commodity Marketing

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

Currently, 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 Upgrader and its Ohio and Wisconsin refineries. The Company supplies feedstock to the Upgrader and to the 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, upgrading and marketing operations. The Company markets light and medium crude oil and NGL sourced from its own production and third-party production. Light crude oil is acquired for processing by the Lima Refinery and the Superior Refinery. The Company supplies a portion of the synthetic crude oil produced at the Upgrader to the Lima Refinery and Superior Refinery, and markets the rest to refiners in Canada and the 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 Company trades natural gas to generate revenue from managed assets, including transportation and natural gas storage facilities.

Upgrading Operations

The Company owns and operates the Upgrader. The Upgrader is designed to process blended heavy crude oil feedstock, creating high quality, low sulphur synthetic crude oil and ultra-low sulphur diesel and recover diluent from the feedstock for return to and reuse in the field. Synthetic crude oil is used as refinery feedstock for the production of transportation fuels in Canada and the U.S.

The Upgrader was commissioned in 1992 with an original design capacity of 46,000 bbls/day of synthetic crude oil. In 2007, the Upgrader commenced production of transportation grade diesel. The Upgrader's current rated production capacity is 80,000 bbls/day of synthetic crude oil, diluent and ultra low sulphur diesel.

Production at the Upgrader in 2019 averaged 54,930 bbls/day of synthetic crude oil, 13,880 bbls/day of diluent and 6,100 bbls/day of ultra low sulphur diesel. In addition, as by-products of its upgrading operations, the Upgrader produced approximately 339 long ton/day of sulphur and 961 long ton/day of petroleum coke during 2019. These products are sold in Canadian and international markets.

Canadian Refined Products

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

Until its sale by the Company in November 2019, light oil was processed and refined products were produced at the Prince George Refinery and such products were also acquired from third-party refiners and marketed through the Company's retail and commercial petroleum outlets and through direct marketing to third-party dealers and end users. On November 1, 2019, the Prince George Refinery was sold to Tidewater and in conjunction with the deal, Husky agreed to a five-year offtake agreement to purchase the refined products at market price. Asphalt and residual products are produced at the Asphalt Refinery and are marketed directly or through the Company's eight terminals located in Western Canada and the U.S. Midwest.

Asphalt Refinery

The Asphalt Refinery processes heavy crude oil and bitumen into asphalt products used in road construction and maintenance. The refinery has a throughput capacity of 30,000 bbls/day of heavy crude oil and bitumen. The refinery also produces straight run gasoline, bulk distillates and residuals. The straight run gasoline stream is removed and re-circulated into HMLP's pipeline network as pipeline diluent. The distillate stream is transferred to the Upgrader and treated for blending into the Husky Synthetic Blend ("**HSB**") stream. Residuals are a blend of medium and light distillate and gas oil streams, which are typically sold directly to customers as refinery feedstock or drilling and well-fracturing fluids, or used in asphalt cutbacks and emulsions.

Refinery throughput averaged 26,400 bbls/day of blended heavy crude oil and bitumen feedstock during 2019. Due to the seasonal demand for asphalt products, many asphalt refineries typically operate at full capacity only during the normal paving season in Canada and the northern U.S. The Company has implemented various strategies to increase refinery throughput during the other months of the year that are outside of the normal paving season, such as increasing storage capacity and developing U.S. markets for asphalt products. This allows the Asphalt Refinery to run at or near full capacity throughout the year.

Asphalt Distribution Network

In addition to sales directly from the Asphalt Refinery, the Company, through the Husky Asphalt division, has an asphalt distribution network which consists of seven asphalt terminals located at: Kamloops, British Columbia; Edmonton and Lethbridge, Alberta; Yorkton, Saskatchewan; Winnipeg, Manitoba; Rhinelander, Wisconsin; and Crookston, Minnesota, and an emulsion plant located at Saskatoon, Saskatchewan. The Company also markets asphalt from independently operated terminals in the states of Washington, Minnesota, Wisconsin and Ohio.

Ethanol Plants

In September 2006, the Company commissioned an ethanol plant in Lloydminster, Saskatchewan. The plant has an annual nameplate capacity of 130 million litres. In December 2007, the Minnedosa, Manitoba ethanol plant was commissioned with an annual nameplate capacity of 130 million litres and both plants are currently operating above that capacity due to efforts to optimize yield. In 2019, ethanol production averaged 823 thousand litres/day.

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 and ethanol produced at the plant has a low carbon intensity designation.

Other Supply Arrangements

During 2019, the Company purchased approximately 27,250 bbls/day of refined petroleum products of which 25,850 bbls/day were pursuant to an agreement with Imperial Oil. The Company also acquired approximately 7,600 bbls/day of refined petroleum products pursuant to exchange agreements with third-party refiners in addition to Imperial Oil.

Retail and Commercial Network

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

On January 8, 2019, the Company announced its intention to market and potentially sell its Canadian Retail and Commercial Fuels Network. The strategic review continues to progress.

As of December 31, 2019, there were 552 independently operated Husky and Esso-branded petroleum product outlets. These outlets include travel centres, convenience stores and cardlock and bulk distribution facilities located coast-to-coast. The Company's network of travel centres features a proprietary cardlock system that enables commercial customers to make purchases using a fuel payment card that processes transactions, provides detailed billing and offers purchase controls and spending limits, as well as advanced fraud protection. A variety of full and self-serve retail stations serve urban and rural markets across the country, while the Company's bulk distributors offer direct sales to commercial and agricultural markets in the Prairie provinces.

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

The following table shows the number of Husky and Esso-branded petroleum outlets by province as of December 31, 2019:

	British Columbia	Alberta	Saskatchewan	Manitoba	Ontario	Quebec	New Brunswick	**2019 Total**	2018 Total
Husky-Branded Petroleum Outlets									
Retail Owned Outlets	36	43	7	12	54	—	—	152	165
Leased	31	27	3	7	23	—	—	91	97
Independent Retailers	46	60	12	3	13	—	—	134	136
Total	**113**	**130**	**22**	**22**	**90**	**—**	**—**	**377**	398
Esso-Branded Petroleum Outlets									
Retail Owned Outlets	18	18	4	4	15	—	—	59	48
Leased	3	4	—	3	3	—	—	13	8
Independent Retailers	33	23	4	6	30	6	1	103	100
Total	**54**	**45**	**8**	**13**	**48**	**6**	**1**	**175**	156
Cardlocks[1]	**49**	**45**	**9**	**11**	**42**	**7**	**1**	**164**	162
Convenience Stores[1]	**80**	**83**	**13**	**21**	**94**	**—**	**—**	**291**	296
Restaurants	**8**	**9**	**3**	**1**	**13**	**—**	**—**	**34**	34

[1] Located at branded petroleum outlets.

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

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

	Years ended December 31,		
Average Daily Sales Volume *(mbbls/day)*	**2019**	2018	2017
Gasoline	**20.5**	21.7	22.3
Diesel fuel	**25.7**	26.5	22.8
Liquefied Petroleum Gas	**0.5**	0.2	0.2
	46.7	48.4	45.3

U.S. Refining and Marketing

Lima Refinery

The Lima Refinery has a crude oil throughput capacity, depending on crude slate, of 175,000 bbls/day. The Lima Refinery, prior to the completion of the crude oil flexibility project, processed both light sweet crude oil and a small percentage of heavy crude oil feedstock sourced from the U.S. and Canada, which includes Canadian synthetic crude oil, including HSB produced by the 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 and Energy Transfer Partners pipeline systems and by rail car to primary markets in Ohio, Illinois, Indiana, Pennsylvania and southern Michigan.

During 2019, total production throughput at the Lima Refinery averaged 176,000 bbls/day excluding days for the 2019 shutdown. Production, excluding days for the crude oil flexibility project shutdown, consisted of an average of 85,000 bbls/day of gasoline, 72,000 bbls/day of distillates and 19,000 bbls/day of other products.

In 2016, the Company completed the first stage of the crude oil flexibility project to enable the refinery to process up to 10,000 bbls/day of heavy crude oil feedstock. The refinery completed a planned turnaround in the fourth quarter of 2019 and made final tie-ins for the project. The refinery is now designed to allow for the processing of up to 40,000 bbls/day of heavy crude oil from Western Canada and the ability to swing between light and heavy crude oil feedstock. The project was completed in early 2020 and the refinery will ramp up to full rates during the first quarter of 2020.

BP-Husky Toledo Refinery

The BP-Husky Toledo Refinery has a nameplate capacity of 160,000 bbls/day. Products from the refinery include low sulphur gasoline, ultra-low sulphur diesel, aviation fuels and by-products.

A feedstock optimization project completed during the 2016 turnaround improved the BP-Husky Toledo Refinery's ability to process high-TAN crude oil to support production from the Sunrise Energy Project. Since January 1, 2017, the Company has been marketing its share of the joint operation's refined product.

During 2019, the Company's share of total throughput averaged 63,100 bbls/day, with the Company's share of sales of gasoline averaging 39,000 bbls/day, distillates averaging 18,700 bbls/day and other fuel and feedstock averaging 7,100 bbls/day.

Superior Refinery

On November 8, 2017, the Company completed the acquisition of the Superior Refinery, which has a permitted throughput capacity of 50,000 bbls/day and an operating capacity of 45,000 bbls/day on its current crude slate. The refinery produces motor fuel products and asphalt from light and heavy crude oil originating from North Dakota and Western Canada.

The refinery also has associated infrastructure including five storage and distribution terminals that are strategically located throughout the northern area of the United States. These terminals include: the Superior products terminal; the Duluth Terminal in Duluth, Minnesota, which has a storage capacity of 200,000 barrels; the Duluth Marine Terminal in Duluth, Minnesota which has a storage capacity of 14,000 barrels; the Rhinelander Terminal in Rhinelander, Wisconsin, which has a storage capacity of 166,000 barrels; and the Crookston Terminal in Crookston, Minnesota, which has a storage capacity of 156,000 barrels.

On April 26, 2018, the Superior Refinery experienced an incident while preparing for a major turnaround and was taken out of operation. During 2019, demolition, site preparation work and permitting were completed, and the rebuild work commenced. The investment in the rebuild is estimated to be approximately US$750 million, of which the Company anticipates a substantial portion will be recovered from property damage insurance. This represents a change from the previous estimate of greater than US$400 million, with the change being due to a more complete assessment of the extent of equipment damage from the April 26, 2018 incident. The Company anticipates that lost income through April 2020 will be compensated by business interruption insurance. The refinery is being rebuilt with the same configuration and with the capability to run continuously at the 45,000 barrel-per-day operating capacity and will be able to produce a full slate of products, including asphalt, gasoline and diesel. Full operations are expected to resume in 2021.

Offshore

Asia Pacific

China

Liwan Gas Project

The Liwan Gas Project includes the conventional 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% working interest in the Liwan 3-1 and Liuhua 34-2 fields and a 75% working interest in the Liuhua 29-1 field, and China National Offshore Oil Corporation Limited ("**CNOOC**") has 51% and 25% working interests, respectively. The initial development of the Liwan 3-1 and Liuhua 34-2 fields was separated into deepwater and shallow water development projects, with the Company acting as deepwater operator and CNOOC acting as shallow water operator. The deepwater infrastructure includes production wells and trees, subsea pipelines and manifolds that produce to twin 22-inch deepwater pipelines running approximately 78 kilometres to a shallow water central platform. The shallow water infrastructure includes the central platform standing in approximately 120 metres of water, a 261-kilometre shallow water pipeline running from the central platform to the onshore Gaolan Gas Plant, which has liquids separation facilities, 10 spherical NGL storage tanks, an export jetty, control facilities as well as administrative and accommodation buildings.

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

In 2019, total conventional natural gas sales from Liwan 3-1 and Liuhua 34-2 averaged 311 mmcf/day and 38 mmcf/day, respectively. In 2019, the Company's working interest share of production from the two fields was 171 mmcf/day of conventional natural gas and 7,400 bbls/day of NGL.

Substantial construction work was completed in 2019 at Liuhua 29-1 development project, the third deepwater gas field of the Liwan Gas Project. During the year, the remaining three wells were drilled, and all seven wells in the full field development were fully completed. The production pipeline and the mono-ethylene glycol supply line were engineered, fabricated and installed. The project is now approximately 80% complete, and construction activities will resume again in March 2020. First gas production from the Liuhua 29-1 field is expected by the end of 2020, with target production of 45 mmcf/day conventional natural gas (Husky working interest) and 1,800 bbls/day NGL (Husky working interest) when fully ramped up.

Block 15/33

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

The Company is progressing commercial development plans following the successful drilling and testing of the XJ34-3-2 exploration well. The block boundaries have been expanded and additional exploration and appraisal drilling is planned in 2020.

Block 16/25

The Company executed a PSC in April 2017 for an exploration block offshore China. Block 16/25 is located in the Pearl River Mouth Basin in the South China Sea, about 150 kilometres southeast of the Hong Kong Special Administrative Region and approximately 72 kilometres northeast of Block 15/33. The block covers an area of 44 square kilometres in water depths of approximately 85 to100 metres.

The Company drilled one exploration well in the third quarter of 2018, which encountered non-commercial hydrocarbons. This block was released and the costs written off in 2019 after technical evaluations were completed.

Blocks 22/11 and 23/07

The Company and CNOOC signed two PSCs for Blocks 22/11 and 23/07 in the Beibu Gulf area of the South China Sea in the first half of 2018. The Company is the operator of both blocks with a working interest of 100% during the exploration phase. In the event of a commercial discovery, its partner CNOOC may assume a participating partnership interest of up to 51% in either or both blocks for the development and production phases. The Company has elected to move into the second exploratory phase for Block 23/07.

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% working interest during exploration, while CPC Corporation has the right to participate in the development program up to a 50% interest.

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

Indonesia

Madura Strait

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

In 2019, total BD field sales averaged 82 mmcf/day of conventional natural gas and 6,100 bbls/day of NGL. The Company's working interest share of production was 32 mmcf/day of conventional natural gas and 2,500 bbls/day of NGL.

At the MDA and MBH fields, the two shallow water platforms have been fully installed. Five MDA and two MBH field production wells are expected to be drilled in the 2020 timeframe pending regulatory approval. Contracting for a floating production unit to process the gas is also planned to be finalized during 2020 with fabrication to take place in 2021/2022. Gas production and sales are planned to commence in 2021 with gas sales under government-approved contracts into the East Java gas market. Subsequently, an additional shallow water field, MDK, is scheduled to be developed and tied into the MDA and MBH infrastructure. Pre-engineering activities and approvals progressed at the MAC field, where an approved Plan of Development is in place.

Anugerah

The Company executed a PSC in February 2014 with the Government of Indonesia for the Anugerah contract area. The Company holds a 100% interest in the Anugerah Block, which is located in the East Java Basin approximately 150 kilometres east of the Madura Strait. The block covers an area of 1,420,000 net acres (8,215 square kilometres).

The Company previously acquired 2-D and 3-D seismic survey data on the contract area, which was required during the first three years of the PSC. An analysis of those data and data from offset block information indicates that exploratory drilling would not be economic. The block will be relinquished in February 2020.

Atlantic

Overview

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

White Rose Field and Satellite Extensions

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

First oil was achieved at White Rose in November 2005. The White Rose field currently has 13 production wells, 10 water injection wells and three gas injection wells. Two infill production wells were completed during 2019. The Company's share of light crude oil production from the White Rose field was 7,200 bbls/day (Husky working interest) during 2019.

On May 31, 2010, first oil was achieved from North Amethyst, the first satellite extension at the White Rose field. The field is located approximately six kilometres southwest of the *SeaRose* FPSO. Production flows from North Amethyst to the *SeaRose* FPSO through a series of subsea flow lines. In September 2016, the Company began production from the deeper Hibernia formation at North Amethyst utilizing existing infrastructure. As of December 31, 2019, the field had eight production wells and four water injection wells. During 2019, light crude oil production from North Amethyst was 1,900 bbls/day (Husky working interest).

Initial production from West White Rose was achieved in September 2011 through a two-well pilot project. The pilot wells have helped provide further information on the reservoir to refine development plans for the full West White Rose field. During 2019, light crude oil production from this satellite field was 500 bbls/day (Husky working interest).

Production commenced from the South White Rose Extension in 2015 with production wells supported by both gas flood and water injection. As at December 31, 2019, the project had three production wells, one water injection well and one gas injection well. During 2019, light crude oil production from the South White Rose Extension was 2,700 bbls/day (Husky working interest).

In May 2017, the Company and its co-venturers announced plans to proceed with full field development at West White Rose using a fixed drilling platform. First oil is forecasted around the end of 2022, with the West White Rose Project expected to ramp up to peak production of 52,500 bbls/day (Husky working interest) in 2026 as development wells are brought online. Like the other White Rose tiebacks, the platform will leverage existing offshore infrastructure including the *SeaRose* FPSO. Construction of various components for the West White Rose platform is underway at sites in NL, and in Ingleside, Texas, where the facility's topsides are being fabricated.

At the graving dock in Argentia, NL, four slipforms were completed on the outer caisson for the project's concrete gravity structure and the first three interior decks were installed. The inner pedestal for the concrete structure will be slipformed to its full height during the 2020 construction season. Following a schedule review in early 2019, Husky and its partners decided to adjust the tow-out and installation date for the concrete gravity structure from 2021 to 2022. Project spending has been adjusted to meet the new schedule. As of December 31, 2019, the project was approximately 55% complete.

In late January 2019, the Company began a staged ramp-up of production at the White Rose field following a 250-cubic-metre oil spill from a failed flowline connector at the South White Rose Extension in November 2018. The flowline connector was replaced with one with a higher tensile strength and processes were updated to prevent a recurrence. All sections of the field were back in operation during August 2019. Husky's investigation revealed that hydrate formation caused the flowline connector to separate. The C-NLOPB, which regulates the industry offshore NL, continues its investigation.

Terra Nova Field

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

On December 20, 2019, production operations on the *Terra Nova* FPSO were safely shut-in in response to a C-NLOPB order citing insufficient redundancy of fire water pumps.

As at December 31, 2019, there were 15 development wells drilled in the Graben area, consisting of nine production wells, four water injection wells and two gas injection wells. In the East Flank area, there were 12 development wells, consisting of eight production wells and four water injection wells. The Far East has one extended reach production well and an extended reach water injection well. The operator continues to progress delineation and development opportunities at Terra Nova.

Light crude oil production during 2019 from the Terra Nova field was 4,100 bbls/day (Husky working interest).

East Coast Exploration

The Company holds working interests ranging from 5.8% to 100% in 23 Significant Discovery Areas in the Jeanne d'Arc Basin and Flemish Pass Basin, offshore NL and Baffin Island.

The Tiger's Eye D-17 exploration well, drilled approximately 10 kilometres south of the White Rose field during the second quarter of 2019, did not encounter commercial quantities of hydrocarbons and has been expensed.

The Company continues to evaluate previous hydrocarbon discoveries at the White Rose A-24 exploration well, north of the *SeaRose* FPSO, and the Northwest White Rose A-78 well.

The Company and its partner continue to assess potential development of Bay du Nord and other discoveries in the Flemish Pass Basin. A benefits framework agreement was reached with the Government of NL in July 2018, based on an FPSO-based development concept to produce resources at Bay du Nord and Bay de Verde. Technological and commercial evaluations continue. The Company holds a 35% non-operated working interest in the Bay du Nord, Bay de Verde, Baccalieu, Harpoon and Mizzen discoveries.

The Company was awarded a parcel of land during the November 2019 C-NLOPB land sale. The EL is northwest of White Rose and adjacent to other Husky land holdings.

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

Disclosure of Oil and Gas Activities

Operating Netback Analysis[1]

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

	Year Ended	Three Months Ended			
Average Per Unit Amounts	**Dec 31, 2019**	**Dec 31, 2019**	Sept 30, 2019	June 30, 2019	Mar 31, 2019
Company Total[2]					
Sales volume *(mboe/day)*	**290.0**	**311.3**	294.8	268.4	285.2
Gross Revenue *($/boe)*[3]	**$48.37**	**$46.06**	$47.54	$53.35	$47.20
Royalties *($/boe)*	**$3.29**	**$3.25**	$3.21	$3.69	$3.03
Production and Operating Costs *($/boe)*[3]	**$15.53**	**$15.25**	$14.83	$15.83	$16.30
Transportation Costs *($/boe)*[4]	**$0.16**	**$0.08**	$0.19	$0.22	$0.18
Operating netback *($/boe)*	**$29.39**	**$27.48**	$29.31	$33.61	$27.69
Light and Medium Crude Oil *($/bbl)*					
Canada - Western Canada					
Gross Revenue[3]	**$47.11**	**$36.50**	$44.07	$52.32	$56.94
Royalties	**$9.10**	**$10.24**	$9.90	$9.65	$6.73
Production and Operating Costs[3]	**$26.43**	**$22.30**	$16.68	$36.63	$28.07
Operating netback	**$11.58**	**$3.96**	$17.48	$6.04	$22.14
Canada - Atlantic Canada					
Gross Revenue	**$86.44**	**$84.54**	$83.47	$92.00	$92.12
Royalties	**$8.15**	**$7.17**	$6.96	$11.07	$10.06
Production and Operating Costs	**$42.20**	**$30.48**	$32.21	$52.75	$92.01
Transportation Costs[4]	**$2.89**	**$0.97**	$2.66	$4.74	$6.87
Operating netback	**$33.20**	**$45.92**	$41.64	$23.44	($16.82)
Canada - Total					
Gross Revenue[3]	**$72.85**	**$71.67**	$71.32	$77.07	$73.09
Royalties	**$8.50**	**$7.99**	$7.87	$10.53	$8.26
Production and Operating Costs[3]	**$36.85**	**$28.29**	$27.42	$46.66	$57.52
Transportation Costs[4]	**$1.90**	**$0.71**	$1.84	$2.95	$3.16
Operating netback	**$25.60**	**$34.67**	$34.19	$16.92	$4.14
Heavy Crude Oil *($/bbl)*					
Canada - Total					
Gross Revenue[3]	**$54.70**	**$50.01**	$56.72	$63.15	$49.38
Royalties	**$5.08**	**$4.27**	$5.26	$5.86	$4.99
Production and Operating Costs[3]	**$34.84**	**$35.97**	$37.63	$32.31	$35.85
Operating netback	**$14.78**	**$9.77**	$13.83	$24.98	$8.54
Bitumen *($/bbl)*					
Canada - Total					
Gross Revenue[3][4]	**$49.00**	**$41.39**	$51.09	$58.32	$46.64
Royalties	**$2.45**	**$2.12**	$2.60	$3.18	$1.96
Production and Operating Costs[3]	**$12.73**	**$12.58**	$12.15	$12.39	$13.79
Operating netback	**$33.82**	**$26.69**	$36.34	$42.75	$30.89

Average Per Unit Amounts	Year Ended Dec 31, 2019	Three Months Ended Dec 31, 2019	Sept 30, 2019	June 30, 2019	Mar 31, 2019
Conventional Natural Gas *($/mcf)*					
Canada - Total					
Gross Revenue(3)(5)	**$1.72**	**$2.29**	$0.95	$1.20	$2.46
Royalties(5)(6)	**($0.01)**	**$0.07**	($0.11)	($0.09)	$0.07
Production and Operating Costs(3)	**$1.68**	**$1.71**	$1.39	$1.91	$1.60
Operating netback	**$0.05**	**$0.51**	($0.33)	($0.63)	$0.80
China					
Gross Revenue	**$14.02**	**$14.31**	$13.28	$14.05	$14.35
Royalties	**$0.80**	**$0.88**	$0.75	$0.75	$0.76
Production and Operating Costs	**$0.90**	**$0.86**	$1.02	$0.87	$0.88
Operating netback	**$12.32**	**$12.57**	$11.51	$12.43	$12.71
Indonesia(7)					
Gross Revenue	**$9.87**	**$9.85**	$9.82	$9.94	$9.88
Royalties	**$1.10**	**$1.01**	$1.06	$1.07	$1.25
Production and Operating Costs	**$1.40**	**$1.47**	$1.04	$1.59	$1.53
Operating netback	**$7.37**	**$7.37**	$7.72	$7.28	$7.10
Total					
Gross Revenue(3)	**$6.44**	**$7.02**	$5.44	$6.19	$7.12
Royalties	**$0.33**	**$0.41**	$0.24	$0.28	$0.40
Production and Operating Costs(3)	**$1.40**	**$1.39**	$1.25	$1.54	$1.34
Operating netback	**$4.71**	**$5.22**	$3.95	$4.37	$5.38
Natural Gas Liquids *($/bbl)*					
Canada - Total					
Gross Revenue(3)	**$23.38**	**$23.88**	$17.13	$25.06	$27.47
Royalties	**$3.44**	**$3.36**	$2.26	$3.01	$4.93
Production and Operating Costs(3)	**$10.20**	**$10.88**	$8.76	$11.18	$10.14
Operating netback	**$9.74**	**$9.64**	$6.11	$10.87	$12.40
China					
Gross Revenue	**$67.28**	**$67.87**	$61.81	$69.77	$69.11
Royalties	**$3.82**	**$3.93**	$3.47	$3.92	$3.90
Production and Operating Costs	**$5.43**	**$5.16**	$6.10	$5.25	$5.27
Operating netback	**$58.03**	**$58.78**	$52.24	$60.60	$59.94
Indonesia(7)					
Gross Revenue	**$88.91**	**$90.33**	$83.03	$101.07	$81.96
Royalties	**$13.75**	**$14.31**	$12.95	$15.32	$12.61
Production and Operating Costs	**$8.39**	**$8.82**	$6.22	$9.52	$9.19
Operating netback	**$66.77**	**$67.20**	$63.86	$76.23	$60.16
Total					
Gross Revenue(3)	**$44.99**	**$45.72**	$38.39	$50.22	$46.07
Royalties	**$4.70**	**$4.56**	$3.94	$4.86	$5.41
Production and Operating Costs(3)	**$8.43**	**$8.62**	$7.66	$8.91	$8.52
Operating netback	**$31.86**	**$32.54**	$26.80	$36.45	$32.14

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

Production History

Average Gross Daily Production	Year Ended Dec 31, 2019	Three Months Ended Dec 31, 2019	Sept 30, 2019	June 30, 2019	Mar 31, 2019
Canada - Western Canada					
Light and Medium Crude Oil *(mbbls/day)*	**8.5**	**8.9**	9.4	7.4	8.9
Heavy Crude Oil *(mbbls/day)*	**30.2**	**32.6**	31.6	28.9	27.6
Bitumen *(mbbls/day)*	**128.8**	**137.8**	126.4	120.4	130.3
Conventional Natural Gas *(mmcf/day)*	**297.5**	**297.7**	310.4	279.6	301.8
NGL *(mbbls/day)*	**12.7**	**12.6**	13.0	10.7	14.4
Canada - Atlantic					
Light and Medium Crude Oil *(mbbls/day)*	**16.4**	**24.4**	21.1	12.2	7.6
China - Asia Pacific(1)					
Conventional Natural Gas *(mmcf/day)*	**171.0**	**183.1**	158.3	161.5	180.6
NGL *(mbbls/day)*	**7.4**	**8.3**	6.6	7.1	7.7
Indonesia - Asia Pacific(2)					
Conventional Natural Gas *(mmcf/day)*	**32.4**	**26.6**	34.6	34.0	34.4
NGL *(mbbls/day)*	**2.5**	**2.1**	2.8	2.5	2.6
Total Gross Production *(mboe/day)*	**290.0**	**311.3**	294.8	268.4	285.2

(1) Reported production volumes include Husky's working interest production from the Liwan Gas Project (49%).
(2) Reported production volumes include Husky's working interest production from the BD Project (40%). Revenues and expenses related to the Husky-CNOOC Madura Ltd. joint venture are accounted for under the equity method for consolidated financial statement purposes.

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

Producing Wells	Oil Wells Gross	Oil Wells Net	Conventional Natural Gas Wells Gross	Conventional Natural Gas Wells Net	Total Gross	Total Net
Canada						
Alberta	1,526	1,337	1,690	1,174	3,216	2,511
Saskatchewan	2,209	2,138	82	81	2,291	2,219
British Columbia	—	—	121	121	121	121
Newfoundland	22	6	—	—	22	6
	3,757	3,481	1,893	1,376	5,650	4,857
International						
China	—	—	10	5	10	5
Indonesia	—	—	4	2	4	2
	—	—	14	7	14	7
As at December 31, 2019	**3,757**	**3,481**	**1,907**	**1,383**	**5,664**	**4,864**

Non-Producing Wells	Oil Wells Gross	Oil Wells Net	Conventional Natural Gas Wells Gross	Conventional Natural Gas Wells Net	Total Gross	Total Net
Canada						
Alberta	1,516	1,385	841	632	2,357	2,017
Saskatchewan	3,755	3,601	184	165	3,939	3,766
British Columbia	—	—	12	10	12	10
As at December 31, 2019	**5,271**	**4,986**	**1,037**	**807**	**6,308**	**5,793**

(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, 2019.
(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, 2019, the Company had a royalty interest in 832 wells, of which 452 were oil producers and 380 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 2019, there were 959 gross and 869 net oil wells and 75 gross and 63 net conventional natural gas wells that were completed in two or more formations and from which production is not commingled.

Of the 34 mmboe of Proved Developed Non-Producing reserves as of year-end 2019, approximately 27 mmboe are associated with wells drilled in 2019 in the thermal bitumen projects and Sunrise Energy Project that will be placed on production in 2020. An additional 3 mmboe are associated with the Company's Wembley liquids-rich gas resource play. The remaining volumes are associated with optimization programs within existing fields scheduled over the next five years. Because the remaining capital is small relative to drilling and completion costs, the associated reserves are considered developed. There are no other non-producing wells attributed with material reserves.

Properties with No Attributed Reserves

Unproved Acreage *(thousands of acres)*	Gross	Net
Western Canada		
Alberta	2,976	2,552
Saskatchewan	634	619
British Columbia	180	152
	3,790	3,323
Northwest Territories and Arctic	471	458
Atlantic	2,808	1,137
	7,069	4,918
China	317	306
Indonesia	2,034	1,665
Taiwan	1,904	1,428
As at December 31, 2019	**11,324**	**8,138**

Where Husky holds interests in different formations under the same surface area pursuant to separate leases, the acreage for each lease is included in the gross and net amounts.

As at December 31, 2019, over the next 12 months, development rights to approximately 226 thousand net acres, or less than 7%, of the Company's net unproved acreage in Western Canada will be subject to expiry.

As at December 31, 2019, over the next 12 months, development rights to 109 thousand net acres in Atlantic will be subject to expiry.

As at December 31, 2019 over the next 12 months, development rights to 15 thousand net acres in the Northwest Territories are subject to relinquishment.

As at December 31, 2019, over the next 12 months, development rights to the 1,428 thousand net acres in Taiwan are subject to expiry. The Company is analyzing the 3-D survey from 2017 to identify potential drilling prospects and is evaluating options to extend the expiry to beyond 2020 or proceed to the exploration phase.

As of December 31, 2019, over the next 12 months, the Indonesian Anugerah PSC of 1,420 thousand net acres will be fully relinquished.

The Company has commitments totaling approximately $268 million related to exploration to be completed in Atlantic between 2022 and 2023. Not fulfilling commitments in accordance with licensing timelines triggers forfeiture of security deposits of 25% of unfulfilled commitments.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

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

Abandonment and Reclamation Costs

There are no significant abandonment or reclamation costs, no unusually high expected development costs or operating costs and no contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations 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 17 of the Company's audited consolidated financial statements for the year ended December 31, 2019.

Drilling Activity - Number of Wells Drilled

	Year Ended December 31, 2019							
	Western Canada		Atlantic		China		Indonesia	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploration								
Oil	1.0	1.0	1.0	0.4	—	—	—	—
Gas	—	—	—	—	—	—	—	—
	1.0	1.0	1.0	0.4	—	—	—	—
Development								
Oil	120.0	117.0	2.0	1.5	—	—	—	—
Gas	15.0	11.0	—	—	3.0	2.3	—	—
	135.0	128.0	2.0	1.5	3.0	2.3	—	—
	136.0	**129.0**	**3.0**	**1.9**	**3.0**	**2.3**	**—**	**—**
Stratigraphic Test Wells	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**
Service Wells	**—**	**—**	**—**	**—**	**—**	**—**	**—**	**—**

Costs Incurred

($millions)	Total	Western Canada	Atlantic	Total Canada	China	Indonesia[1]
Property acquisition - Unproven	—	—	—	—	—	—
Property acquisition - Proven	6	6	—	6	—	—
Exploration	93	27	57	84	9	—
Development	2,764	1,362	1,059	2,421	342	1
2019	**2,863**	**1,395**	**1,116**	**2,511**	**351**	**1**

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

Oil and Gas Reserves Disclosure

Overview

Husky's oil and gas reserves are estimated in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook ("**COGEH**"), and the reserves data disclosed conforms with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**"). All of Husky's oil and gas reserves estimates are prepared by internal qualified reserves evaluation staff using a formalized process for determining, approving and booking reserves.

For the purposes of Husky's NI 51-101 reserves disclosure in this year's AIF, Sproule Associates Limited. ("**Sproule**"), an independent firm of qualified reserves evaluators, was engaged to conduct a complete audit and review of 100% of Husky's oil and gas 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.

The Audit Committee of the Board 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 has approved, on the recommendation of the Audit Committee, the content of Husky's disclosure in this AIF of its reserves data and other oil and gas information.

Disclosure of Oil and Gas Information

Unless otherwise noted in this document, all provided reserves estimates have a preparation date of January 31, 2020 and an effective date of December 31, 2019 and are Husky's total proved and probable reserves. Gross reserves or gross production are reserves or production attributable to Husky's working interest prior to deduction of royalties; net reserves or net production are reserves or production net of such royalties. Gross or net production reported refers to sales volume, unless otherwise indicated. Unless otherwise noted, production and reserves figures are stated on a gross basis. Unless otherwise indicated, oil and gas commodity prices are quoted after the effects of hedging gains and losses. Unless otherwise indicated, all financial information is in accordance with IFRS. Note that the numbers in each column of the tables throughout this section may not add due to rounding.

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

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

Summary of Oil and Conventional Natural Gas Reserves
As at December 31, 2019
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	36.4	31.6	44.7	43.1	141.1	127.3	222.1	202.0
Developed Non-producing	0.4	0.4	0.7	0.6	27.3	25.3	28.4	26.3
Undeveloped	66.4	62.3	1.3	1.2	775.0	689.1	842.7	752.6
Total Proved	103.2	94.2	46.6	44.9	943.3	841.7	1,093.2	980.9
Probable	91.8	77.0	19.0	18.3	422.3	337.0	533.1	432.3
Total Proved Plus Probable	**195.0**	**171.3**	**65.7**	**63.2**	**1,365.6**	**1,178.7**	**1,626.3**	**1,413.2**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	686.3	606.8	37.3	28.4	373.8	331.4
Developed Non-producing	22.7	20.7	2.0	1.7	34.2	31.5
Undeveloped	106.1	99.2	17.3	14.9	877.7	784.1
Total Proved	815.0	726.7	56.6	45.0	1,285.7	1,147.0
Probable	339.4	313.3	43.7	35.9	633.4	520.4
Total Proved Plus Probable	**1,154.4**	**1,039.9**	**100.3**	**80.9**	**1,919.1**	**1,667.4**

China

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

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	335.3	317.0	11.2	10.6	67.1	63.4
Developed Non-producing	—	—	—	—	—	—
Undeveloped	160.5	157.0	5.8	5.7	32.6	31.9
Total Proved	495.8	474.0	17.0	16.3	99.7	95.3
Probable	119.5	113.0	4.5	4.2	24.4	23.1
Total Proved Plus Probable	**615.2**	**587.1**	**21.5**	**20.6**	**124.0**	**118.4**

Indonesia

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbls)*		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	140.6	103.4	5.1	3.9	28.6	21.1
Developed Non-producing	—	—	—	—	—	—
Undeveloped	101.0	67.4	—	—	16.8	11.2
Total Proved	241.6	170.8	5.1	3.9	45.4	32.3
Probable	91.5	54.6	1.6	0.7	16.9	9.8
Total Proved Plus Probable	**333.1**	**225.3**	**6.8**	**4.6**	**62.3**	**42.1**

Total

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbls)*		Total Oil *(mmbbls)*	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Proved								
Developed Producing	36.4	31.6	44.7	43.1	141.1	127.3	222.1	202.0
Developed Non-producing	0.4	0.4	0.7	0.6	27.3	25.3	28.4	26.3
Undeveloped	66.4	62.3	1.3	1.2	775.0	689.1	842.7	752.6
Total Proved	103.2	94.2	46.6	44.9	943.3	841.7	1,093.2	980.9
Probable	91.8	77.0	19.0	18.3	422.3	337.0	533.1	432.3
Total Proved Plus Probable	**195.0**	**171.3**	**65.7**	**63.2**	**1,365.6**	**1,178.7**	**1,626.3**	**1,413.2**

	Conventional Natural Gas *(bcf)*		Natural Gas Liquids *(mmbbls)*		Total *(mmboe)*	
	Gross	Net	Gross	Net	Gross	Net
Proved						
Developed Producing	1,162.1	1,027.2	53.6	42.8	469.4	416.0
Developed Non-producing	22.7	20.7	2.0	1.7	34.2	31.5
Undeveloped	367.6	323.6	23.1	20.6	927.1	827.2
Total Proved	1,552.4	1,371.5	78.8	65.2	1,430.7	1,274.7
Probable	550.4	480.9	49.8	40.9	674.7	553.3
Total Proved Plus Probable	**2,102.8**	**1,852.4**	**128.6**	**106.0**	**2,105.4**	**1,827.9**

Future Net Revenue Tables

Summary of Net Present Values of Future Net Revenue - Before Income Taxes and Discounted
As at December 31, 2019
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	(410.8)	3,056.0	3,433.1	3,359.1	3,198.1	10.36
Developed Non-producing[(1)]	(250.7)	94.3	177.7	196.7	194.8	5.64
Undeveloped	18,276.3	8,278.9	4,340.5	2,271.5	1,021.6	5.54
Total Proved	17,614.7	11,429.1	7,951.2	5,827.3	4,414.5	6.93
Probable	21,349.9	11,903.2	7,785.5	5,526.7	4,138.2	14.96
Total Proved Plus Probable	**38,964.7**	**23,332.3**	**15,736.7**	**11,354.0**	**8,552.7**	**9.44**

(1) In the Heavy Oil properties there are approximately 9,000 oil and gas wells with no reserves assigned that carry surface land, maintenance and property taxes that also form part of each non-producing property's (that has reserves) operating costs. Accordingly, these costs have been included in the reserves reports in the Proved Developed Non-producing category.

China

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	0%	5%	10%	15%	20%	*($/boe)*
Proved						
Developed Producing	4,069.5	3,514.9	3,095.5	2,770.0	2,511.5	48.81
Developed Non-producing	—	—	—	—	—	—
Undeveloped	1,259.6	861.1	593.5	407.0	272.5	18.60
Total Proved	5,329.0	4,376.0	3,689.0	3,177.0	2,783.9	38.70
Probable	1,372.0	909.0	645.7	485.3	381.3	27.99
Total Proved Plus Probable	**6,701.0**	**5,285.0**	**4,334.8**	**3,662.3**	**3,165.2**	**36.61**

Indonesia

	Before Income Taxes and Discounted at (%/year)					Unit Value Discounted at 10%
($ millions)	0%	5%	10%	15%	20%	*($/boe)*
Proved						
Developed Producing	610.2	508.6	434.4	378.7	335.7	20.59
Developed Non-producing	—	—	—	—	—	—
Undeveloped	339.4	270.3	217.2	175.8	143.1	19.35
Total Proved	949.6	778.9	651.6	554.5	478.7	20.16
Probable	291.4	190.3	127.5	87.1	60.1	12.99
Total Proved Plus Probable	**1,241.0**	**969.2**	**779.2**	**641.6**	**538.9**	**18.49**

Total

($ millions)	Before Income Taxes and Discounted at (%/year) 0%	5%	10%	15%	20%	Unit Value Discounted at 10% ($/boe)
Proved						
Developed Producing	4,268.8	7,079.5	6,963.0	6,507.8	6,045.3	16.74
Developed Non-producing[(1)]	(250.7)	94.3	177.7	196.7	194.8	5.64
Undeveloped	19,875.3	9,410.3	5,151.2	2,854.3	1,437.1	6.23
Total Proved	23,893.4	16,584.1	12,291.9	9,558.7	7,677.2	9.64
Probable	23,013.3	13,002.5	8,558.7	6,099.1	4,579.6	15.47
Total Proved Plus Probable	**46,906.7**	**29,586.5**	**20,850.6**	**15,657.9**	**12,256.9**	**11.41**

(1) In the Heavy Oil properties there are approximately 9,000 oil and gas wells with no reserves assigned that carry surface land, maintenance and property taxes that are part of each non-producing property's (that has reserves) operating costs. Accordingly, these costs have been included in the reserves reports in the Proved Developed Non-producing category.

Summary of Net Present Values of Future Net Revenue - After Income Taxes and Discounted
As at December 31, 2019
Forecast Prices and Costs

Canada

	After Income Taxes and Discounted at (%/year)				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed Producing	(370.9)	2,264.0	2,543.7	2,485.7	2,364.5
Developed Non-producing[(1)]	(197.0)	60.5	121.2	134.0	131.6
Undeveloped	13,686.9	5,929.6	2,913.4	1,343.9	404.2
Total Proved	13,118.9	8,254.1	5,578.3	3,963.7	2,900.4
Probable	15,847.2	8,706.2	5,639.2	3,973.5	2,957.6
Total Proved Plus Probable	**28,966.2**	**16,960.2**	**11,217.5**	**7,937.3**	**5,858.0**

(1) In the Heavy Oil properties there are approximately 9,000 oil and gas wells with no reserves assigned that carry surface land, maintenance and property taxes that are part of each non-producing property's (that has reserves) operating costs. Accordingly, these costs have been included in the reserves reports in the Proved Developed Non-producing category.

China

	After Income Taxes and Discounted at (%/year)				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed Producing	3,049.9	2,634.5	2,320.6	2,077.2	1,883.9
Developed Non-producing	—	—	—	—	—
Undeveloped	942.3	627.7	415.3	266.5	158.7
Total Proved	3,992.1	3,262.2	2,735.9	2,343.7	2,042.7
Probable	1,028.8	681.6	484.3	364.1	286.2
Total Proved Plus Probable	**5,020.9**	**3,943.8**	**3,220.2**	**2,707.8**	**2,328.9**

Indonesia

	After Income Taxes and Discounted at (%/year)				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed Producing	467.8	399.7	348.8	309.7	279.0
Developed Non-producing	—	—	—	—	—
Undeveloped	235.5	188.4	151.7	122.5	99.2
Total Proved	703.3	588.1	500.4	432.2	378.2
Probable	153.4	102.2	69.2	47.0	31.7
Total Proved Plus Probable	**856.7**	**690.3**	**569.6**	**479.3**	**409.9**

Total

	After Income Taxes and Discounted at (%/year)				
($ millions)	0%	5%	10%	15%	20%
Proved					
Developed Producing	3,146.8	5,298.1	5,213.1	4,872.6	4,527.5
Developed Non-producing[(1)]	(197.0)	60.5	121.2	134.0	131.6
Undeveloped	14,864.6	6,745.8	3,480.4	1,733.0	662.1
Total Proved	17,814.4	12,104.4	8,814.7	6,739.6	5,321.2
Probable	17,029.4	9,490.0	6,192.7	4,384.7	3,275.5
Total Proved Plus Probable	**34,843.8**	**21,594.4**	**15,007.3**	**11,124.3**	**8,596.7**

(1) In the Heavy Oil properties there are approximately 9,000 oil and gas wells with no reserves assigned that carry surface land, maintenance and property taxes that are part of each non-producing property's (that has reserves) operating costs. Accordingly, these costs have been included in the reserves reports in the Proved Developed Non-producing category.

Total Future Net Revenue for Total Proved Plus Probable Reserves - Undiscounted
As at December 31, 2019
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	77,491.1	9,445.9	29,621.8	13,851.6	6,957.0	17,614.7	4,495.8	13,118.9
Total Proved Plus Probable	120,422.7	17,946.9	38,437.7	17,905.4	7,168.1	38,964.7	9,998.5	28,966.2
China								
Total Proved	7,489.4	410.8	1,185.2	390.9	173.4	5,329.0	1,336.9	3,992.1
Total Proved Plus Probable	9,222.4	505.2	1,449.1	390.9	176.3	6,701.0	1,680.1	5,020.9
Indonesia								
Total Proved	2,898.4	812.7	1,050.4	52.3	33.4	949.6	246.3	703.3
Total Proved Plus Probable	3,975.2	1,284.4	1,314.3	92.6	42.9	1,241.0	384.3	856.7
Total								
Total Proved	87,878.9	10,669.5	31,857.4	14,294.8	7,163.8	23,893.4	6,079.0	17,814.4
Total Proved Plus Probable	133,620.3	19,736.5	41,201.0	18,388.8	7,387.2	46,906.7	12,063.0	34,843.8

Future Net Revenue by Product Type
As at December 31, 2019
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	73.5	0.47	—	—	—	—	73.5	0.47
Heavy Crude Oil	376.8	8.12	—	—	—	—	376.8	8.12
Bitumen	7,345.7	8.73	—	—	—	—	7,345.7	8.73
Total Oil	7,795.9	7.47	—	—	—	—	7,795.9	7.47
Conventional Natural Gas	155.3	1.49	3,689.0	38.70	651.6	20.16	4,496.0	19.40
Total Proved	**7,951.2**	**6.93**	**3,689.0**	**38.70**	**651.6**	**20.16**	**12,291.9**	**9.64**
Total Proved Plus Probable								
Light & Medium Crude Oil	2,308.4	9.64	—	—	—	—	2,308.4	9.64
Heavy Crude Oil	682.8	10.46	—	—	—	—	682.8	10.46
Bitumen	12,074.7	10.24	—	—	—	—	12,074.7	10.24
Total Oil	15,065.9	10.16	—	—	—	—	15,065.9	10.16
Conventional Natural Gas	670.8	3.65	4,334.8	36.61	779.2	18.49	5,784.7	16.80
Total Proved Plus Probable	**15,736.7**	**9.44**	**4,334.8**	**36.61**	**779.2**	**18.49**	**20,850.6**	**11.41**

(1) By-products, including solution gas, NGL and other associated by-products, are included in their main product group (conventional 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 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 2019, see "Statement of Reserves Data and Other Oil and Gas Information – Disclosure of Oil and Gas Activities – Operating Netback Analysis".

	Light Crude Oil			Medium Crude Oil	Heavy Crude Oil
	WTI *(U.S. $/bbl)*	Brent *(U.S. $/bbl)*	Edmonton *(Cdn $/bbl)*	Hardisty Bow River *(Cdn $/bbl)*	Lloyd Heavy API *(Cdn $/bbl)*
Historical					
2019	57.03	64.30	69.22	59.44	54.21
Forecast					
2020	61.00	66.33	72.64	58.43	51.23
2021	63.75	67.94	76.06	63.00	56.11
2022	66.18	70.06	78.35	64.99	57.72
2023	67.91	71.66	80.71	66.91	59.45
2024	69.48	73.27	82.64	68.65	61.09
2025	71.07	74.57	84.60	70.41	62.75
2026	72.68	76.22	86.57	72.20	64.43
2027	74.24	77.83	88.49	73.91	66.04
2028	75.73	79.36	90.31	75.53	67.55
2029	77.24	80.92	92.17	77.18	69.08
Thereafter	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr

	Bitumen	Conventional Natural Gas	Natural Gas Liquids		
	Hardisty WCS *(Cdn $/bbl)*	AECO *(Cdn $/GJ)*	Edmonton Propane *(Cdn $/bbl)*	Edmonton Butane *(Cdn $/bbl)*	Edmonton Condensate *(Cdn $/bbl)*
Historical					
2019	58.72	1.54	17.22	23.78	70.11
Forecast					
2020	57.57	1.93	26.36	42.10	76.83
2021	62.35	2.20	29.80	47.03	79.82
2022	64.33	2.48	32.94	50.66	82.30
2023	66.23	2.57	34.00	52.21	84.72
2024	67.97	2.66	34.88	53.48	86.71
2025	69.72	2.74	35.78	54.77	88.73
2026	71.49	2.80	36.69	56.07	90.77
2027	73.20	2.87	37.57	57.32	92.76
2028	74.80	2.93	38.41	58.50	94.65
2029	76.43	3.00	39.26	59.71	96.57
Thereafter	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr	2.00%/yr

	Asia Pacific			
	China	Indonesia		
	Conventional Natural Gas (U.S. $/mcf)[1]	Conventional Natural Gas (U.S. $/mcf)[1]	Inflation rates[2]	Exchange rates[3]
Historical				
2019	10.71	7.46	1.53	0.75
Forecast				
2020	10.98	7.53	—	0.76
2021	10.51	7.18	1.67	0.77
2022	9.44	7.08	2.00	0.79
2023	9.26	7.20	2.00	0.79
2024	9.30	7.35	2.00	0.79
2025	9.36	7.51	2.00	0.79
2026	9.49	7.64	2.00	0.79
2027	9.59	7.81	2.00	0.79
2028	9.49	7.98	2.00	0.79
2029	9.46	8.07	2.00	0.79
Thereafter			2.00	0.79

(1) Conventional natural gas prices in China and Indonesia have been updated from the prior year values due to changes in exchange rates and are the volume weighted average based on the various GSAs.
(2) Inflation rates represent a percentage for forecasting costs.
(3) Exchange rates used to generate the benchmark reference prices are quoted in U.S. dollar to Canadian dollar.

Reconciliation of Gross Proved Reserves

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Canada - Western Canada							
End of 2018	18.2	53.7	889.7	961.6	1,288.1	46.3	1,222.6
Technical Revisions	(0.5)	(0.2)	(12.1)	(12.7)	(496.7)	(6.0)	(101.5)
Economic Factors	(0.1)	(1.1)	(0.3)	(1.6)	(14.8)	(0.6)	(4.6)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	0.1	—	—	0.1	0.1	—	0.1
Extensions & Improved Recovery	3.3	5.8	113.0	122.2	146.7	21.5	168.1
Production	(2.6)	(11.6)	(47.0)	(61.2)	(108.5)	(4.6)	(83.9)
End of 2019	**18.3**	**46.6**	**943.3**	**1,008.3**	**815.0**	**56.6**	**1,200.7**
Canada - Atlantic							
End of 2018	93.3	—		93.3	—	—	93.3
Technical Revisions	(2.6)	—	—	(2.6)	—	—	(2.6)
Economic Factors	(0.1)	—	—	(0.1)	—	—	(0.1)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	0.2	—	—	0.2	—	—	0.2
Production	(6.0)	—	—	(6.0)	—	—	(6.0)
End of 2019	**84.9**	**—**	**—**	**84.9**	**—**	**—**	**84.9**
China							
End of 2018	—	—	—	—	529.6	18.3	106.6
Technical Revisions	—	—	—	—	1.7	0.5	0.7
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	26.8	1.0	5.5
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(62.4)	(2.7)	(13.1)
End of 2019	**—**	**—**	**—**	**—**	**495.8**	**17.0**	**99.7**
Indonesia							
End of 2018	—	—	—	—	253.7	6.1	48.3
Technical Revisions	—	—	—	—	(0.3)	—	(0.1)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(11.8)	(0.9)	(2.9)
End of 2019	**—**	**—**	**—**	**—**	**241.6**	**5.1**	**45.4**

	Light & Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Bitumen (mmbbls)	Total Oil (mmbbls)	Conventional Natural Gas (bcf)	Natural Gas Liquids (mmbbls)	Total (mmboe)
Total							
End of 2018	111.5	53.7	889.7	1,054.9	2,071.4	70.7	1,470.8
Technical Revisions	(3.1)	(0.2)	(12.1)	(15.3)	(495.3)	(5.6)	(103.4)
Economic Factors	(0.2)	(1.1)	(0.3)	(1.7)	(14.8)	(0.6)	(4.7)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	0.1	—	—	0.1	26.9	1.0	5.5
Extensions & Improved Recovery	3.5	5.8	113.0	122.4	146.7	21.5	168.3
Production	(8.6)	(11.6)	(47.0)	(67.2)	(182.7)	(8.2)	(105.8)
End of 2019	**103.2**	**46.6**	**943.3**	**1,093.2**	**1,552.4**	**78.8**	**1,430.7**

At December 31, 2019, the Company's proved oil and gas reserves were 1,431 mmboe, down from 1,471 mmboe at the end of 2018. The Company's 2019 reserves replacement ratio, defined as net additions of proved reserves divided by total production during the period, was 67% excluding economic revisions (62% including economic revisions).

Major changes to proved reserves in 2019 included:

- Western Canada Extensions & Improved Recovery additions of 168 mmboe which included 40 mmbbls from one new and 35 mmbbls from three existing Lloydminster bitumen SAGD projects (16 mmbbls transferred from probable reserves), 20 mmbbls at the Tucker Thermal Project (transferred from probable reserves), 15 mmbbls at the Sunrise Oil Sands project and 38 mmboe from Wembley (including 111 bcf of conventional natural gas and 19 mmbbls of NGL) and 5 mmboe from Wapiti new locations.
- Discoveries included 27 bcf of conventional natural gas and 1 mmbbls of NGL for Liuhua 29-1 transferred from probable reserves as Technical Revisions.
- Western Canada Technical Revisions are associated with the updated long-term strategic plan where less liquid rich gas plays are no longer funded. This resulted in a reduction of proved undeveloped reserves of 443 bcf (90% of the Technical Revisions) of conventional natural gas and 5 mmbbls of NGL.
- Economic Factors of 5 mmboe are mainly associated with lower gas prices in Western Canada.

Reconciliation of Gross Probable Reserves

	Light & Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Bitumen (mmbbls)	Total Oil (mmbbls)	Conventional Natural Gas (bcf)	Natural Gas Liquids (mmbbls)	Total (mmboe)
Canada - Western Canada							
End of 2018	5.4	21.9	831.8	859.1	462.9	10.7	946.9
Technical Revisions	(1.5)	(7.9)	(430.1)	(439.5)	(358.7)	(5.2)	(504.4)
Economic Factors	—	(0.2)	(0.3)	(0.4)	0.9	—	(0.2)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	3.7	5.1	20.9	29.8	234.2	38.2	107.0
Production	—	—	—	—	—	—	—
End of 2019	**7.7**	**19.0**	**422.3**	**449.0**	**339.4**	**43.7**	**549.3**
Canada - Atlantic							
End of 2018	83.8	—	—	83.8	—	—	83.8
Technical Revisions	0.2	—	—	0.2	—	—	0.2
Economic Factors	0.1	—	—	0.1	—	—	0.1
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	0.1	—	—	0.1	—	—	0.1
Production	—	—	—	—	—	—	—
End of 2019	**84.1**	**—**	**—**	**84.1**	**—**	**—**	**84.1**
China							
End of 2018	—	—	—	—	109.0	4.1	22.2
Technical Revisions	—	—	—	—	10.4	0.4	2.1
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
End of 2019	**—**	**—**	**—**	**—**	**119.5**	**4.5**	**24.4**
Indonesia							
End of 2018	—	—	—	—	91.5	1.7	16.9
Technical Revisions	—	—	—	—	0.1	—	—
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	—	—	—
End of 2019	**—**	**—**	**—**	**—**	**91.5**	**1.6**	**16.9**

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Total							
End of 2018	89.2	21.9	831.8	942.9	663.4	16.4	1,069.9
Technical Revisions	(1.3)	(7.9)	(430.1)	(439.3)	(348.2)	(4.8)	(502.1)
Economic Factors	0.1	(0.2)	(0.3)	(0.4)	0.9	—	(0.2)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	3.8	5.1	20.9	29.9	234.2	38.2	107.1
Production	—	—	—	—	—	—	—
End of 2019	**91.8**	**19.0**	**422.3**	**533.1**	**550.4**	**49.8**	**674.7**

Major changes to probable reserves in 2019 included:

- Western Canada Extensions & Improved Recovery include the additions at Wembley of 207 bcf of conventional natural gas and 36 mmbbls of NGL.
- China Technical Revisions include 17 bcf from an increase in the original gas in place and the GSA for Liuhua 34-2. At Liuhua 29-1, 27 bcf were transferred from probable to proved reserves. This transfer was offset by a technical increase of 20 bcf due to updated mapping.
- Sunrise Energy Project bitumen locations include negative Technical Revisions of 285 mmbbls for the expansions, and associated locations, that are no longer funded in the next five years of the updated strategic plan. Sunrise probable reserves were also negatively impacted by an update of the geological interpretation impacting the probable recovery of 91 mmbbls.
- As indicated in the proved reserves reconciliation, 37 mmbbls of probable bitumen reserves were transferred to proved reserves.
- Western Canada less liquids-rich gas projects were also impacted by the updated strategic plan resulting in a reduction of 312 bcf of conventional natural gas and 3 mmbbls of NGL probable reserves.

Reconciliation of Gross Proved Plus Probable Reserves

	Light & Medium Crude Oil *(mmbbls)*	Heavy Crude Oil *(mmbbls)*	Bitumen *(mmbbls)*	Total Oil *(mmbbls)*	Conventional Natural Gas *(bcf)*	Natural Gas Liquids *(mmbbls)*	Total *(mmboe)*
Canada - Western Canada							
End of 2018	23.5	75.6	1,721.5	1,820.7	1,751.0	57.0	2,169.6
Technical Revisions	(2.0)	(8.0)	(442.2)	(452.2)	(855.3)	(11.2)	(606.0)
Economic Factors	(0.1)	(1.3)	(0.7)	(2.0)	(13.9)	(0.5)	(4.9)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	0.1	—	—	0.1	0.1	—	0.1
Extensions & Improved Recovery	7.0	11.0	133.9	151.9	381.0	59.7	275.1
Production	(2.6)	(11.6)	(47.0)	(61.2)	(108.5)	(4.6)	(83.9)
End of 2019	**26.0**	**65.7**	**1,365.6**	**1,457.3**	**1,154.4**	**100.3**	**1,750.0**
Canada - Atlantic							
End of 2018	177.1	—	—	177.1	—	—	177.1
Technical Revisions	(2.4)	—	—	(2.4)	—	—	(2.4)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	0.3	—	—	0.3	—	—	0.3
Production	(6.0)	—	—	(6.0)	—	—	(6.0)
End of 2019	**169.1**	**—**	**—**	**169.1**	**—**	**—**	**169.1**
China							
End of 2018	—	—	—	—	638.7	22.4	128.8
Technical Revisions	—	—	—	—	12.1	0.9	2.9
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	26.8	1.0	5.5
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(62.4)	(2.7)	(13.1)
End of 2019	**—**	**—**	**—**	**—**	**615.2**	**21.5**	**124.0**
Indonesia							
End of 2018	—	—	—	—	345.1	7.7	65.3
Technical Revisions	—	—	—	—	(0.2)	—	(0.1)
Economic Factors	—	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	—	—	—	—	—	—	—
Extensions & Improved Recovery	—	—	—	—	—	—	—
Production	—	—	—	—	(11.8)	(0.9)	(2.9)
End of 2019	**—**	**—**	**—**	**—**	**333.1**	**6.8**	**62.3**

	Light & Medium Crude Oil (mmbbls)	Heavy Crude Oil (mmbbls)	Bitumen (mmbbls)	Total Oil (mmbbls)	Conventional Natural Gas (bcf)	Natural Gas Liquids (mmbbls)	Total (mmboe)
Total							
End of 2018	200.6	75.6	1,721.5	1,997.8	2,734.8	87.1	2,540.7
Technical Revisions	(4.4)	(8.0)	(442.2)	(454.6)	(843.4)	(10.4)	(605.5)
Economic Factors	(0.1)	(1.3)	(0.7)	(2.0)	(13.9)	(0.5)	(4.9)
Acquisitions	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—	—
Discoveries	0.1	—	—	0.1	27.0	1.0	5.6
Extensions & Improved Recovery	7.3	11.0	133.9	152.2	381.0	59.7	275.4
Production	(8.6)	(11.6)	(47.0)	(67.2)	(182.7)	(8.2)	(105.8)
End of 2019	**195.0**	**65.7**	**1,365.6**	**1,626.3**	**2,102.8**	**128.6**	**2,105.4**

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 conventional natural gas reserves. Classifications of reserves as proved or probable are only attempts to define the degree of uncertainty associated with the estimates. In addition, whereas proved reserves are those reserves that can be estimated with a high degree of certainty to be economically producible, probable reserves are those reserves that are as likely as not to be recovered. Therefore, probable reserves estimates, by definition, have a higher degree of uncertainty than proved reserves.

Approximately 46% of Husky's gross proved undeveloped reserves are assigned to the Sunrise Energy Project. Production from Phase I of the project started in March 2015, and wells will be drilled in the future to keep the plant at full capacity. Approximately 36% of Husky's gross proved undeveloped reserves are assigned to 15 heavy oil thermal projects in the Lloydminster area that are classified as bitumen. Approximately 7% of Husky's gross proved undeveloped reserves are assigned to the West White Rose Project fields, 5% are assigned to the China and Indonesia projects, and 3% are assigned to the liquids-rich Wembley area.

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 and timing of developing the various proved undeveloped and probable undeveloped reserves , including decisions to defer development of proved undeveloped reserves beyond two years, are based on various factors including strategic considerations, changing economic conditions, changes to government regulations including the setting of production limits, technical performance, development plan optimization, facility capacity, pipeline constraints, and the size of the development program. The development opportunities are pursued at a pace dependent on capital availability and its allocation in accordance with Husky's business plans.

As at December 31, 2019, there were no material proved undeveloped reserves that have remained undeveloped for greater than five years, except as follows. The Sunrise Energy Project proved undeveloped bitumen reserves are scheduled to be developed and produced over the next 50 years to fully utilize the steam plant and processing capacity over the life of the current facilities. Similarly, the probable undeveloped bitumen reserves are scheduled to be developed and produced over the next 50 years which includes capital spending on facility debottlenecks, expansions and additions within the next five years. The four existing Lloydminster thermal bitumen projects are scheduled to start up from 2020 through 2022. One new Lloydminster thermal bitumen project received regulatory approval and is scheduled to be brought online in 2023. The Lloydminster thermal and Tucker bitumen proved and probable undeveloped locations are scheduled to be developed over the next one to 20 years to utilize each project's steam and processing capacities. The West White Rose Project is scheduled to have the first proved undeveloped reserves placed on production in 2022. The remaining proved and probable undeveloped locations are scheduled to be placed on production by 2028. Proved undeveloped reserves for Liuhua 29-1 are scheduled to be brought on production in 2020. Proved undeveloped reserves in Madura are scheduled to be brought on production in 2021. Wembley's proved and probable undeveloped locations are scheduled to be developed over the next five and seven years, respectively, in accordance with the Company's business plan for that project. The reasons these proved undeveloped reserves will be undeveloped for greater than five years are set out in the previous paragraph.

Proved Undeveloped Reserves

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
2017	61.8	60.8	—	—	136.9	585.0	198.7	645.9
2018	8.4	69.8	1.0	1.0	177.3	747.9	186.6	818.6
2019	**2.8**	**66.4**	**1.3**	**1.3**	**109.9**	**775.0**	**113.9**	**842.7**

	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
2017	71.9	451.6	1.0	3.6	211.7	724.8
2018	310.4	739.1	9.2	12.4	247.6	954.2
2019	**133.1**	**367.6**	**18.3**	**23.1**	**154.5**	**927.1**

Probable Undeveloped Reserves

	Light & Medium Crude Oil *(mmbbls)*		Heavy Crude Oil *(mmbbls)*		Bitumen *(mmbbls)*		Total Oil *(mmbbls)*	
	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end	First Attributed	Total at year-end
2017	0.3	80.8	—	—	42.3	810.9	42.7	891.8
2018	0.7	71.2	1.9	2.2	265.6	778.4	268.2	851.8
2019	**3.4**	**65.4**	**4.2**	**4.2**	**20.9**	**368.9**	**28.4**	**438.4**

	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
2017	302.7	558.8	7.1	9.0	100.2	993.9
2018	139.0	472.2	4.9	7.8	296.2	938.3
2019	**224.9**	**348.8**	**37.0**	**39.7**	**102.9**	**536.3**

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, no unusually high expected development costs or operating costs and no contractual obligations to produce and sell a significant portion of production at prices substantially below those which could be realized but for those contractual obligations 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 17 of the Company's audited consolidated financial statements for the year ended December 31, 2019.

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 and debt 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, 2019:

	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)*
2020	2,097.2	2,171.3	390.9	390.9	42.1	60.4	2,530.2	2,622.6
2021	1,460.6	1,516.4	—	—	10.2	32.2	1,470.8	1,548.5
2022	1,342.4	1,505.7	—	—	—	—	1,342.4	1,505.7
2023	613.5	824.8	—	—	—	—	613.5	824.8
2024	767.2	985.1	—	—	—	—	767.2	985.1
Remaining	7,570.7	10,902.2	—	—	—	—	7,570.7	10,902.2
Total	**13,851.6**	**17,905.4**	**390.9**	**390.9**	**52.3**	**92.6**	**14,294.8**	**18,388.8**

Production Estimates

Yearly Production Estimates for 2020

	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	21.3	27.6	132.7	181.7	257.8	13.2	237.8
Total Gross Probable	3.7	2.2	10.6	16.6	27.8	1.9	23.1
Total Gross Proved Plus Probable	**25.0**	**29.9**	**143.4**	**198.2**	**285.6**	**15.1**	**260.9**
China							
Total Gross Proved				—	187.6	7.4	38.6
Total Gross Probable				—	0.4	0.2	0.3
Total Gross Proved Plus Probable	**—**	**—**	**—**	**—**	**187.9**	**7.6**	**38.9**
Indonesia							
Total Gross Proved				—	38.3	2.2	8.5
Total Gross Probable				—	—	0.1	0.1
Total Gross Proved Plus Probable	**—**	**—**	**—**	**—**	**38.3**	**2.3**	**8.6**
Total							
Total Gross Proved	21.3	27.6	132.7	181.7	483.6	22.7	285.0
Total Gross Probable	3.7	2.2	10.6	16.6	28.2	2.2	23.5
Total Gross Proved Plus Probable	**25.0**	**29.9**	**143.4**	**198.2**	**511.8**	**24.9**	**308.4**

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

INDUSTRY OVERVIEW

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

Global crude oil inventories remained high in 2019, with the U.S. becoming a net oil exporter and the world's largest oil producer. The U.S. Energy Information Administration estimated that U.S. crude oil production averaged 12.2 mmbbls/day in 2019 and will average 13.3 mmbbls/day in 2020 and 13.17 mmbbls/day in 2021, with the majority of the forecasted production growth in the Permian region of Texas and New Mexico.

On December 6, 2019, the Organization of the Petroleum Exporting Countries ("**OPEC**") and several non-OPEC members announced further production reductions of 0.5 mmbbls/day, from the previous 1.2 mmbbls/day in 2018, through to March 2020.

In Canada, the Alberta government set province-wide mandatory oil production cuts in an attempt to rebalance the market. This curtailment became effective January 1, 2019. During 2019, the production limit increased from 3.56 mmbbls/day, at January 2019, to 3.81 mmbbls/day at December 2019. The program has been extended to December 31, 2020.

U.S. dry natural gas production set a new record in 2019, averaging 92.0 bcf/day. The U.S. Energy Information Administration forecasts dry natural gas production will rise to 94.7 bcf/day in 2020 and then decline to 94.1 bcf/day in 2021.[(1)]

(1) *"Short-Term Energy Outlook", January 2020, U.S. Energy Information Administration*

Commodity Pricing

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

Global crude oil benchmarks remained weakened in 2019 primarily due to a continued oversupply as the U.S became a net oil exporter and the world's largest oil producer. Conversely, the WCS benchmark strengthened in 2019 as the Government of Alberta set province-wide mandatory production quotas to restrict oil supplies entering the market, and consequently the differential between the WCS benchmark and other North American benchmarks tightened in 2019 compared to 2018. The price of West Texas Intermediate ("**WTI**") averaged US$57.03/bbl in 2019 compared to US$64.77/bbl in 2018. The price of Brent averaged US$64.30/bbl in 2019 compared to US$70.97/bbl in 2018. The price of WCS averaged US$44.28/bbl in 2019 compared to US$38.46/bbl in 2018.

Market Access[(1)]

The existing pipeline network servicing Western Canada is operating at capacity and producers are relying more on rail to move incremental volumes. Pipelines are the preferred mode of transporting large volumes of crude oil for long distances over land, given the inherent economies of scale associated with pipelines.

In Canada, the Alberta government set province-wide mandatory oil production cuts effective January 1, 2019 in an attempt to rebalance the market. This reduced the economic motivation to export crude by rail or develop longer term market access strategies.

Currently, there is insufficient pipeline capacity originating in Western Canada to transport crude oil out of the supply basin to meet the needs of producers. Both the Enbridge Mainline pipeline system and Trans Mountain pipeline continue to operate under apportionment, whereby the pipeline companies must reduce shippers' nominated volumes to derive an aggregate amount which can be transported by the pipeline in accordance with its available capacity.

(1) "Crude Oil Forecast, Markets and Transportation", June 2019, Canadian Association of Petroleum Producers.

Royalties, Incentives and Income Taxes

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.

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 Licences and production licences, leases, permits and provincial legislation which may include contingencies such as obligations to perform work or make payments.

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

Environmental Regulations

General

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

Environmental regulations, policies and legal agreements regulate and impose restrictions, liabilities and obligations on how industry is required to handle, store, transport, treat and dispose of emissions, water/waste water, hazardous substances and wastes. Controls and limits on spills, releases and emissions to the environment, including emissions of greenhouse gases ("**GHG**") are required to be diligently managed. Environmental regulations also require that wells and facilities be constructed, operated, maintained, abandoned and reclaimed in compliance with pertinent regulatory requirements. In addition, certain types of operations, including exploration and development projects and significant changes to certain existing projects, may require the submission and approval of environmental impact assessments.

Some examples of potential new or enhanced environmental regulations, and impacts of possible changes, include:

- conventional air pollutant and GHG emissions regulations and mandatory reductions.
- calculation and regulation of carbon intensity of fuels, including transportation fuels.
- fuel reformulation and substitution to support reduced GHG emissions.
- managing air pollutant emissions at equipment and facility levels with the general goal of ensuring compliance with increasingly more stringent ambient air quality standards and air pollutant regulations.
- potential for restrictive operating policies on development in areas of value to species at risk.
- increased restrictions on freshwater licensing.
- increased restrictions on activities in fish-bearing water courses.
- enhanced groundwater and surface water monitoring.
- enhanced water discharge criteria.
- increased restrictions on waste water disposal.
- enhanced water recycle criteria.
- enhanced water crossing monitoring and reporting requirements.
- enhanced requirements for environmental assessment, including the potential for more projects to require assessments, longer review times and additional information requirements.
- water management for hydraulic fracturing.
- wetland compensation.
- induced seismicity.
- feedstock and product transportation by rail, pipeline and roadway.
- pipeline integrity management.
- remediation regulation.
- reclamation criteria.
- constraints mapping, footprint reduction and land use.
- measurement requirements for oil and gas operations.

- investigations of operational upsets that result in emissions.

Water

Numerous regulations are imposed on the oil and gas industry's operations with the general goal of ensuring surface water and fresh groundwater resources are protected. Guidelines cover the following:

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

Water withdrawals are regulated in Husky's operating jurisdictions with the goal of minimizing impacts to freshwater resources. Oil and gas companies have reporting requirements relating to most licensed freshwater withdrawals. Policies dictate water source selection and management. Water withdrawals are further governed by local watershed and/or industry water management plans.

Bill C-69

In Canada, *Bill C-69*, an Act to enact the *Impact Assessment Act* and the *Canadian Energy Regulator Act*, to amend the *Navigation Protection Act* and to make consequential amendments to other Acts, was passed by Parliament on June 21, 2019. The *Impact Assessment Act*, the *Canadian Energy Regulator Act*, the *Canadian Navigable Waters Act*, and associated regulations came into force on August 28, 2019. Of note, the *Impact Assessment Act* creates the new Impact Assessment Agency of Canada, repeals the *Canadian Environmental Assessment Act, 2012*, and provides a new approach to the federal assessment of major projects in Canada. The *Canadian Energy Regulator Act* replaces the National Energy Board with the Canada Energy Regulator ("**CER**") and defines its composition, mandate and powers. The role of the CER is to regulate the exploitation, development and transportation of energy within Parliament's jurisdiction.

The *Canadian Navigable Waters Act* increases protections of navigable waters, expanding the regulation of major works and obstructions, and setting requirements for minor works on all navigable waters.

Bill C-68 was also passed in parliament on June 21, 2019 and outlined amendments to the *Fisheries Act* which came into effect on August 28, 2019. The fish and fish habitat protection provisions under this Act strengthen some protections for aquatic species and protect the interests of people who depend on them, particularly Indigenous communities.

Transport Canada

Effective May 6, 2020, new Transport Canada regulations, entitled Transportation of Dangerous Goods by Rail Security Regulations, will require TDG by Rail specific security plans and training to be established. The new security regulations will affect sites which load prior to or unload following rail transportation, or offer for transportation of dangerous goods in quantities outlined in the regulations.

Migratory Birds and Species at Risk

Canada's oil and gas industry may affect migratory birds and bird habitat as well as habitat impacting sensitive species through land disturbance activities and operating practices (e.g., sludge ponds, vegetation clearing). Industry activities risk contravening the *Migratory Bird Convention Act* (Canada) ("**MBCA**") or the *Species at Risk Act* (Canada) ("**SARA**") and supporting legislation that prohibits the disturbance and destruction of migratory birds, their eggs and/or their nests and mandates the protection and management of sensitive species habitat. There are maximum fines of up to $6 million, with all subsequent fines doubling, for corporations that are convicted under the MBCA. For corporations, current penalties under SARA include fines of $1 million, with potential to double based on subsequent contraventions. U.S. operations are subject to similar requirements pursuant to the *Migratory Bird Treat Act* (USA).

Air and Climate Change

General

Societal attitudes toward climate change have evolved significantly in recent years. Public opposition to companies in the oil sands industry, and in oil and gas generally, has increased. Technology related to climate change is improving and expectations regarding climate change action are growing, resulting in increased stakeholder and consumer pressure to reduce carbon emissions and transition to a low or net zero carbon future. Third parties have initiated litigation related to climate change against certain oil and gas companies and governments around the world. Some oil and gas companies have begun setting net zero carbon emissions targets in response to one or more of these pressures.

The current regulatory environment related to air emissions and climate policy is also dynamic. The impacts of emerging policy are becoming clearer as various jurisdictions finalize 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 or targets.
- market based frameworks.
- equipment and/or facility level emissions performance standards and reporting.
- other regulatory measures including low carbon fuel and renewable fuel standards.

Risks associated with climate change trends and regulations are discussed under "Risk Factors".

International Climate Change Agreements

Canada, Indonesia and China are all signatories to the Paris Agreement drafted at the United Nations Framework Convention on Climate Change Conference of the Parties held in Paris, France in December 2015.

Canada has submitted a Nationally Determined Contribution to reduce GHG emissions by 30% below 2005 levels by 2030. Indonesia has pledged a 29% reduction below a "business as usual" baseline by 2030. China has pledged for total emissions to peak in 2030, but with reductions in emissions per unit GDP by 60-65% from 2005 levels.

There is a commitment to review and increase pledges every five years under the Paris Agreement.

In November 2018, China and Canada signed a memorandum of understanding on climate change cooperation.

On November 4, 2019, the U.S. issued formal notification of withdrawal from the Paris Agreement, to take effect on November 4, 2020.

Canadian Federal Regulations

The Government of Canada has begun addressing emissions from specific sectors of the economy, including working closely with the U.S. government on North American vehicle emissions standards. Canada has adopted renewable fuels regulations, requiring fuel producers and importers to have an average of at least 5% of their gasoline supply come from renewable sources (such as ethanol) and to have an average of at least 2% of their diesel supply come from renewable sources (such as biodiesel).

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

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

Under the BLIERs, three regulations and a guideline were developed within the AQMS. The first of the Multi-Sector Air Pollutants Regulations was published in June 2016. These regulations have included three BLIERs developed under AQMS for the cement sector, reciprocating spark-ignited natural gas engines and non-utility boilers and heaters in industrial sectors. An emissions guideline under the *Environmental Protection Act* (Canada) for stationary gas turbines was published in November 2017. Other sectors and air pollutants are expected to be added to the regulations in the future. For example, a 'Code of Practice for the Management of Air Emissions from Pulp and Paper Facilities was published in July 2018.

The BLIERs pertaining to nitrogen oxides ("**NOx**") emissions from boilers and heaters and NOx emissions from reciprocating engines in industrial facilities are applicable to Husky's Canadian upstream and downstream oil and gas facilities. The Boiler & Heater BLIER and Reciprocating Engine BLIER have introduced performance, design and monitoring standards for both existing and new equipment units, whereas the Stationary Gas Turbine BLIER has only introduced performance and design standards for new equipment.

On October 23, 2018, the Government of Canada announced the federal carbon pricing system would be implemented in part or in whole in Saskatchewan, Manitoba, Ontario and New Brunswick in 2019 as an element of the Pan Canadian Framework on Clean Growth and Climate Change. The remaining provinces and territories either elected to adopt the federal carbon pricing system or presented provincial policies that were deemed equivalent by the federal government. The federal carbon policy has two key elements: a carbon levy applied to fossil fuels ($20 per tonne starting on April 1, 2019 and increasing by $10 annually to $50 per tonne in 2022); and an output-based pricing system for industrial facilities emitting GHG above 50,000 tonnes per year.

On December 20, 2018, the Government of Canada published the Regulatory Proposal for the Output-Based Pricing System ("**OBPS**") Regulation under the *Greenhouse Gas Pollution Pricing Act*. The federal OBPS includes sectorial Output-Based Standards, provisions pertaining to GHG emissions quantification and reporting, as well as details on the administration process and content of verification reports. The federal OBPS would be applicable to faciliites such as Husky's Minnedosa Ethanol Plant effective January 1, 2019.

A federal Clean Fuel Standard ("**CFS**") Discussion Paper was released in February 2017. The CFS will be developed to achieve 30 megatonnes of annual reductions in GHG emissions by 2030 through requiring reductions in fuel carbon intensities based on a life-cycle analysis and will go beyond transportation fuels to include fuels used in industry and buildings. In December 2017, the CFS regulatory framework was published, and in December 2018, the Government of Canada published the Regulatory Design Paper on the CFS. The CFS Regulatory Design Paper focuses on the liquid fuel stream regulations, and key design elements include a carbon intensity reduction of 10 g CO_2/MJ (approximately 11%) by 2030 from a 2016 baseline. A Proposed Regulatory Approach was also released in June 2019 that builds on the previous papers issued by Environment Canada. For liquid fuels, including transportation fuels, draft regulations are expected to be published in early 2020 and final regulations in 2021 with coming into force in 2022.

The Government of Canada is committed to reducing methane emissions from the oil and gas sector by 40% to 45% below 2012 levels by 2025. Final methane reduction regulations for the upstream oil and gas industry were published on April 26, 2018. Emissions sources subject to these regulations include venting from wells and batteries (including associated gas at oil facilities), storage tanks, pneumatic devices, well completions, compressors and fugitive equipment leaks. Final regulations apply to new and existing sources, with the first requirements coming into force in 2020, and the remaining requirements by 2023.

Draft *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* pertaining to the downstream oil and gas industry were published by the Government of Canada in May 2017. The regulations will require the implementation of comprehensive Leak Detection and Repair ("**LDAR**") programs at refineries, upgraders and certain petrochemical facilities. These facilities will also be required to monitor the levels of certain volatile organic compounds at facility perimeters. The final regulations come into force effective January 1, 2020 with the fenceline monitoring requirements expected to be implemented starting in 2020.

Canadian Provincial Greenhouse Gas Regulations

The 2019 provincial election in Alberta brought change to climate policies that were implemented as part of the 2015 Climate Leadership Plan. The newly elected United Conservative Party repealed the provincial fuel levy that was imposed by the previous government. In response to the repeal of the provincial levy, the federal government announced the implementation of the Federal Fuel Levy in Alberta effective January 1, 2020 for any fuels not regulated under the provincial large emitters' regulation. Emissions from the combustion of produced fuel at upstream oil and gas facilities emitting less than 100,000 tonnes of CO_2e per year were exempt from the Alberta provincial fuel use levy until January 1, 2023, to allow time for these facilities to reduce methane emissions under provincial and federal methane regulations. Under federal jurisdiction, the provincial levy exemption for upstream oil will no longer apply, leaving this sector fully exposed to the cost of the Federal Fuel Levy.

The *Alberta Technology Innovation and Emissions Reduction Regulation* (**TIER**), effective January 1, 2020, was proposed as a hybrid policy drawing from elements of previous regulations, *Specified Gas Emitters Regulation* (**SGER**) and *Carbon Competitiveness Incentive Regulation* (**CCIR**). It regulates facilities emitting over 100,000 tonnes CO_2e/year with an opt-in program for smaller emitters and for conventional oil and gas aggregate facilities. TIER allows for the option of a facility specific performance baseline or a sector specific best performance standard as the basis for reduction. The conventional oil and gas aggregated facility opt-in to TIER provides significant emissions intensive, trade exposed ("**EITE**") protection for the sector as participation in the large emitters' regulation exempts the facilities from the Federal Fuel Levy. Alberta's TIER regulation is expected to lessen the financial burden associated with carbon compliance by allowing companies to improve emissions based on historical facility performance rather than being subject to sector intensity benchmarks that are typically set by the largest, most mature operations. Alberta is expected to follow federal pricing of $30/tonne CO_2e in 2020 escalating to $50/tonne CO_2e by 2022.

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

- Applying new emissions design standards to new Alberta facilities.
- Improving measurement and reporting of methane emissions, as well as leak detection and repair requirements.
- Developing a joint initiative on methane reduction and verification for existing facilities and backstopping this with regulated standards that take effect in 2020, with the general goal of ensuring the 2025 target is met.
- On December 13, 2018, the AER released final methane regulations which are effective January 1, 2020.

In December 2017, the Government of Saskatchewan released "Prairie Resilience: A Made-In-Saskatchewan Climate Change Strategy" that includes the implementation of sector-specific output-based performance standards on facilities emitting more than 25,000 tonnes of CO_2e per year. *The Management and Reduction of Greenhouse Gases Amendment Act* ("**MRGHG**"), and various GHG regulations under the Act impose a carbon price (starting at $20 per tonne in 2019 escalating by $10/year up to $50/tonne in 2022) on facilities that emit more than 25,000 tonnes of CO_2e/year. Facilities such as the Upgrader, and Husky's ethanol plant and Saskatchewan thermal projects are subject to MRGHG. As part of the October 23, 2018 Government of Canada's announcement on climate policy equivalency, the Province of Saskatchewan has a carbon tax that applies to all fuel for all facilities under that threshold. Saskatchewan has published the Management and Reduction of Greenhouse Gases (Upstream and Gas Aggregate Facility) and is allowing opt-in of the conventional oil and gas assets to provide EITE protection for the sector, as participation in the large emitters' regulation exempts the facilities from the Federal Fuel Levy.

The Government of Saskatchewan published the *Oil and Gas Emissions Management Regulations* on December 14, 2018, effective January 1, 2019, which apply to oil and gas operations with aggregated emissions exceeding 50,000 tonnes of CO_2e per year. These regulations seek to reduce methane emissions from the oil and gas sector by setting target emissions intensities for various regions within the province. The regulations are intended to reduce provincial methane emissions intensity by 45% by 2025.

On October 3, 2018, Manitoba announced it was canceling its carbon tax. As part of the October 23, 2018 announcement by the federal government, the federal carbon policy applies in full in Manitoba including the application of an output-based standard to Husky's Minnedosa ethanol plant.

On July 3, 2018, Ontario canceled its cap and trade program. As part of the October 23, 2018 announcement by the federal government, the federal carbon policy applies in full in Ontario. On July 4, 2019, Ontario passed the *Emissions Performance Standards Regulation.* The Emissions Performance Standards program ensures large industrial polluters, those emitting over 50,000 tonnes CO_2e annually, are accountable for their GHG emissions and will help Ontario achieve its share of Canada's 2030 emissions reduction target, without a carbon tax.

On June 7, 2016 the *Management of Greenhouse Gas Act* passed in the House of Assembly of NL, establishing the legislative basis for a provincial industrial large emitters program and reporting regulations. The *Management of Greenhouse Gas Reporting Regulations* came into force on March 7, 2017. The Government of Newfoundland and Labrador, in consultation with industry, has developed and proposed GHG regulations for the offshore petroleum production sector to be incorporated by amendment to the *Management of Greenhouse Gas Act* and the Atlantic Accord. On October 23, 2018 the Government of Canada deemed the NL large emitter and fuel levy programs to price carbon as equivalent to federal standards. Subsequently, *Bill C-86* was entered into the House of Commons on October 29, 2018 to amend the Atlantic Accord to enable the C-NLOPB to manage the requirements of the provincial GHG reporting regulations in the offshore petroleum sector.

The NL performance-based regulation imposes carbon pricing (beginning at $20/tonne in 2019 and escalating to $50/tonne in 2022) on petroleum production facilities with GHG emissions exceeding 25,000 tonnes/year. Beginning January 1, 2019, a levy of 4.42 cents per litre on gasoline and 5.37 cents per litre on diesel (both equivalent to $20/tonne) will be applied as part of the carbon tax. This provincial Gasoline and Diesel Tax will be adjusted with a goal of protecting economic competitiveness related to taxation (including carbon tax) of fuel products. The provincial carbon tax rates will only increase to match equivalent increases in carbon taxation programs in neighboring Atlantic provinces. There are noted exemptions for exploration drilling and aviation fuels. However, the addition of this carbon tax to marine diesel will increase operating costs for Atlantic region operations.

U.S. Greenhouse Gas Regulations

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

In May 2010, the EPA finalized the Greenhouse Gas Tailoring Rule. This rule updated 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 GHG. In June 2014, the U.S. Supreme 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.

U.S. Renewable Fuel Standard

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

The RFS program is a national policy that requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel. Obligated parties under the RFS program are refiners or importers of gasoline or diesel fuel. Compliance is achieved by blending renewable fuels into transportation fuels or by obtaining credits, called Renewable Identification Numbers ("**RINs**") to meet an EPA-specified Renewable Volume Obligation ("**RVO**"). The RFS program, through the EPA-specified RVOs, requires refiners to add annually increasing amounts of renewable fuels to their petroleum products or to purchase RINS in lieu of such blending.

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

Abandonment Liability

The AER manages abandonment liability and the licence transfer process using the provisions of Directive 006: Licencee Liability Rating Program and Licence Transfer Process. Directive 006 is designed to prevent Alberta taxpayers from incurring costs to suspend, abandon, remediate and reclaim a well, facility or pipeline. Under the Licencee Liability Rating Program, each licencee is assigned a Liability Management Rating. The Liability Management Rating is the ratio of a licencee's eligible deemed assets under the Licencee Liability Rating Program, the Large Facility Liability Management Program and the Oilfield Waste Liability Program to its deemed liabilities in these programs. The Liability Management Rating assessment is designed to assess a licencee's ability to address its suspension, abandonment, remediation and reclamation liabilities. This assessment is conducted monthly and on receipt of a licence transfer application in which the licencee is the transferor or transferee.

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

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

Consequently, as of June 2016 a condition of transferring existing AER licences, approvals and permits requires transferees to demonstrate that they have a liability management ratio ("**LMR**") of 2.0 or higher immediately following the transfer. If the transfer of the licence 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 some of its assets.

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

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

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

In January 2019, the Supreme Court of Canada's ruling in Redwater was released, wherein the court held that abandonment and reclamation obligations of a debtor are binding on a Trustee, are not creditor claims nor claims provable in bankruptcy, and do not conflict with the general priority scheme in the *Bankruptcy and Insolvency Act* (Canada). The court ruled that the provincial regulatory regime can coexist with and apply alongside the *Bankruptcy and Insolvency Act* (Canada). The governments of Alberta and Saskatchewan have not yet made changes to the abandonment and reclamation obligations of licencees. Similarly, the Government of Canada has not yet made changes to the federal insolvency regime to account for the character and needs of Canada's natural resource industries.

Hydraulic Fracturing

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

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

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

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

Land Use

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

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

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

Environmental, Social and Governance Considerations

Environmental, Social and Governance Policies

Husky has a corporate 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 is safeguarded, contractors and customers are safe and physical assets (such as facilities and equipment) are protected from damage and loss. Husky management also monitors environmental, social and governance ("ESG") risks and reports to the Board through management's Enterprise Risk Management Framework.

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

To reinforce the Health, Safety and Environment Policy, in 2019, Husky held a summit for leaders, attended by members of the HS&E Committee and led by Husky's Chief Executive Officer. During the summit, CEO awards are presented for the initiatives that demonstrate the highest level of operational integrity. Guest and internal speakers present on pertinent issues and the latest developments in the fields of operational integrity and corporate responsibility.

Husky is committed to conducting business fairly and ethically, and in compliance with applicable laws, as well as upholding high standards of business integrity. Husky seeks to deter wrongdoing and promote transparent, honest and ethical behaviour in all its business dealings. Husky has a Code of Business Conduct that is compliant with the International Chamber of Commerce (ICC) Rules of Conduct and Recommendations to Combat Extortion and Bribery, and sets out the standards employees, contractors, officers and directors are expected to meet. This policy includes sections on compliance with laws, avoidance of conflict of interest, proper record-keeping, political contributions, safeguarding company resources, fair competition, avoidance of bribery or other offerings of improper payments, guidelines on accepting payments and entertainment, and other matters. The Code of Business Conduct 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 (the "**Ethics Help Line**") for employees, contractors and other stakeholders to report perceived breaches of Husky's Code of Business Conduct. The Ethics Help Line is hosted by EthicsPoint, an independent service provider. Information from submissions is captured and submitted anonymously to an Ethics Help Line committee made up of legal, audit, security, health, safety and environment, and human resources personnel.

Husky 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, and undertake mandatory annual training.

Husky and its personnel conduct business in many nations around the world and are subject to various sanctions and anti-money laundering laws. Husky's Sanctions & Anti-Money Laundering Policy applies to Husky and all of its subsidiaries and to all officers and employees including temporary and contract staff.

Husky complies with competition laws, the purpose of which are to preserve and promote a competitive market. Husky's Competition Act Compliance Policy assists employees by providing relevant information about competition laws and guidelines to follow in order to ensure these laws are complied with and that any issues are handled appropriately.

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

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

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

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

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

Husky is also committed to the safety of all personnel, the public and the environment when handling and transporting dangerous substances classified as dangerous goods. Husky's Transportation of Dangerous Goods ("TDG") policy ensures dangerous goods are transported in compliance with all TDG laws and Husky standards and procedures.

Husky is committed to ensuring health and safety at work. The ability of every employee and contractor to perform his or 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 Husky's operations, the Alcohol and Drug Policy outlines the standards and expectations associated with alcohol and other drug use, consistent with Husky's overall safety culture. In October 2019, edible cannabis, cannabis extracts and cannabis topicals became legal in Canada and are now being sold under the *Cannabis Act* (Canada). As such, Husky has clarified its Alcohol and Drug Policy to include cannabis edibles, extracts and topicals, and to provide ongoing clarity that misuse of and presence at work while under the influence of legalized cannabis in all its forms is prohibited.

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

Husky Operational Integrity Management System

Husky seeks to manage operational risks by designing and building its facilities and conducting its operations in a safe and reliable manner. The Husky Operational Integrity Management System ("HOIMS") is a set of interrelated policies, aims, requirements and processes that provides a systematic way for Husky to identify, assess and control safety, operational integrity and environmental hazards and associated risks. Additionally, HOIMS establishes standards and procedures integral to safe operations and protecting the environment. Enterprise risk management, emergency preparedness, business continuity and security policies and programs are in place for all operating areas. Strong leadership, with compliance to HOIMS, delivers on Husky's strategic operational integrity objectives and drives HS&E performance. In January 2020, Husky launched the updated HOIMS 2.0.

The fundamental elements of HOIMS 2.0 are:

Leadership and Accountability

- Leaders manage the risks associated with their respective business activities. They are role models who are competent, visible, purposeful and systematic.

Training and Competency

- Personnel are trained and competent to perform their respective role responsibilities.

Risk Management

- Hazards are identified and associated risks assessed, managed and prioritized to prevent incidents.

Operational Integrity Information

- Operational integrity and process safety information is accurate, current and easily accessible

Operating Procedures, Policies and Standards

- Document, maintain and follow operating procedures and standards to meet operational integrity goals.

Management of Change

- Permanent, temporary and emergency changes that impact operational integrity are managed.
- Risks associated with changes are managed.

Emergency Management

- Emergency response, business continuity and security programs are implemented.
- Husky is prepared to manage an emergency, business interruption or security event.

Incident Reporting, Recording, Investigation and Learning

- Report, investigate and learn from Husky incidents and other external high-impact incidents to prevent recurrence.

Safety Control of Work

- Formal processes are in place to allow work to be completed safety.

Project Delivery

- Facilities are designed and built, and assets are developed, to meet business, HS&E and operational integrity requirements.

Supply Chain and Contractor Management

- Supplied services and materials meet Husky's HS&E and operational integrity requirements.

Asset Operation

- Assets and equipment are operated to meet operational integrity goals, preventing injury to people and damage to the environment

Reliability & Integrity

- Reliability and integrity are achieved and improved.

Regulatory Compliance

- Protect Husky's privilege to operate through verifying compliance with legal and regulatory, environmental and social governance requirements.

Assurance, Performance & Improvement

- Performance meets HS&E and operational integrity goals and objectives, and continuously improves.

Pipeline Integrity

Husky has a risk-based Pipeline Integrity Management ("**PIM**") Program which is implemented across all Husky-owned and operated pipelines. The PIM program is a framework, supported by a suite of documents including the Pipeline Operations and Maintenance ("**POMM**") Procedures Manual, which provides guidelines on safe operation and maintenance of pipelines. Numerous processes are implemented throughout the pipeline lifecycle to ensure a proactive approach to managing the integrity, operations and maintenance of the pipeline.

The major processes of managing pipeline integrity include:

- A risk management program, which is used to identify integrity threats throughout the pipeline lifecycle and the risk associated with each threat. Measures are taken to address these risks and reduce them to As Low As Reasonably Practicable ("**ALARP**") level.
- A Geohazard Integrity Management Program, which is used to identify and manage the risks associated with any potential geohazards (geotechnical and hydrotechnical) on pipelines.
- Technology improvements, including fiber optic sensing technology, advanced technologies for flood monitoring at water crossings and satellite monitoring for landslides and in-line visual inspection for high-consequence pipelines.
- Engineering assessment, which involves the evaluation of the fitness for service of pipelines when changes are made to design parameters and at the time of line reactivation to proactively mitigate the risk to process safety.
- Incident investigation, which is used to establish the root cause(s) of failure and apply learnings to enhance pipeline safety and integrity, and to improve integrity programs.
- Annual pipeline integrity reviews, which are conducted for all pipeline systems to review the effectiveness of integrity programs and, where applicable, make recommendations for improvement.
- Training, including Husky's well-established Learning Management System, which defines training and experience requirements for the employees who are engaged in maintaining asset integrity. Husky also has a web-based PIM training program for all employees involved in the operation and maintenance of pipelines.
- Performance targets, which are set annually and tracked quarterly. Immediate steps are taken to address any observed deficiencies.
- A Management of Change process, which is followed for any changes that affect pipeline operational integrity.
- POMM self-assessments, which are conducted to identify any gaps and steps are taken to address any observed deficiencies.
- A PIM Program review, which is a regular review of the PIM program and supporting procedures for alignment with the latest code and regulatory requirements, taking into consideration Husky experience and pipeline industry standards and practices.

Climate Change

As part of long range planning, Husky assesses future compliance costs associated with regulations of GHG emissions in its operations and the evaluation of future projects, based on Husky's outlook for carbon pricing under current and pending regulations. The impact of recently announced regulations is being evaluated as provinces and the federal government finalize carbon pricing regulations. Husky continues to monitor international and domestic efforts to address climate change, including international low carbon fuel standards and regulations and other emerging regulations in the jurisdictions in which Husky operates.

In 2018, Husky's gross Scope 1 GHG emissions were 10,265,000 tCO_2e. Scope 2 GHG emissions in that year were 2,035,000 tCO_2e. GHG emissions numbers for 2019 are expected to be published in Husky's ESG Report in July 2020. Husky uses an internal GHG management framework to guide the process of integrating climate change into its business strategy. Elements of the GHG management framework that inform corporate business strategy include GHG inventory and quantification, GHG reporting and verification, an emissions reduction strategy and a regulatory policy system.

By estimating its current and projected future emissions and understanding forthcoming regulations that may impact its business, Husky determines the areas of its operations that may face future compliance obligations or additional costs from regulation. Husky's Enterprise Risk Management Framework supports decision making via comprehensive and systematic identification and assessment of risks that could materially impact the results of Husky.

Husky's GHG management framework includes a process for climate-related technology assessment, including new innovations that can reduce emissions intensity, and innovations that could disrupt Husky's business strategy. As new technologies are identified by subject matter experts across Husky, they are shared through Husky's Carbon Management Critical Competency Network ("**CMCC**") and as appropriate, are incorporated into regular updates to the Executive Health, Safety and Environment Committee and business unit leadership. Examples of risk from technological innovation that have been reviewed by the CMCC are the accelerating development of renewable energy infrastructure and electrification of the transportation sector. As part of its risk assessment process, Husky reviewed commonly accepted growth forecasts in these sectors to determine the impact to its short, medium and long-term strategy. Husky employs a Marginal Abatement Cost Curve tool as part of a process to review technologies that might qualify for external funding and enhance business cases for technology risk mitigation

Husky recognizes the recommendations of the Financial Stability Board's Task Force on Climate-related Financial Disclosures ("**TCFD**"). Husky voluntarily responds annually to the Climate Disclosure Project ("**CDP**") climate change questionnaire, which as of 2018 has fully adopted the TCFD recommendations.

Environmental Protection

General

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 multiple regulatory requirements cover matters such as: control of air emissions, management and recycling of wastewater, 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. Husky is actively engaged with federal, state, provincial, local agencies and through industry associations to develop sustainable regulations that allow for compliant operations and are also protective of the environment. In addition to existing requirements, Husky recognizes that there are emerging regulatory frameworks that have a potential financial impact on Husky's operations. As part of Husky's review of proposed regulations that may affect its business and operations, Husky may, from time to time, audit and prepare an internal analysis of the possible or expected impact of new regulations, which are subject to various uncertainties. See "Risk Factors" and "Industry Overview".

Husky minimizes impact on the landscape through consideration and application of the mitigation hierarchy, implementing avoidance and mitigation programs where appropriate. Monitoring the effectiveness of mitigation is to occur where mandated by regulatory requirements or stakeholder commitments and may occur when Husky recognizes the value, such as for complex projects or learning opportunities. Where monitoring indicates that corrective action is warranted, Husky's policy is to take an adaptive proactive management approach.

Water

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. Husky believes it is sufficiently prepared to comply with new water regulations. Husky has a corporate Water Standard that mandates Water Risk Assessments and Water Management Plans for its facilities, which include consideration of regulatory risks. The purpose of these Water Risk Assessments is to try to identify and mitigate these risks. Water Risk Assessments consider both known proposed water regulations and possible future regulations (not currently proposed).

Monitoring of surface water and ground water quality relating to hydraulic fracturing operations is not regulated in the jurisdictions in which Husky has these operations. Husky has proactively implemented a recommended practice for completing baseline quality and quantity tests for water wells located in proximity to its hydraulic fracturing operations.

As an active member of the In-situ Water Technology Development Centre, Husky is developing new technologies to recycle waste water, reduce water use and improve energy efficiency. Husky dedicates teams to solving water management challenges by leveraging expertise in hydrogeology, surface water aquatics, hydrology, water treatment and drilling waste management. Husky continues to pursue opportunities to conserve water, through alternative water sources and recycling of produced water. At the Tucker Thermal Project, produced water is recycled and make-up water is sourced from saline, non-potable groundwater. The Sunrise Energy Project recycles produced water and supplements this with process-affected water from a nearby oil sands operation after it has been treated, and lower quality non-saline groundwater that is in contact with bitumen to generate steam for oil recovery. The Lima Refinery has a waste water reuse program that substantially reduces annualy its water needs. As a specific action related to water supply risk in its operations, Husky is participating in a research project to understand potential climate impacts to industrial water supplies on the North Saskatchewan River. This multi-year study is a collaborative project with academia and another industry partner.

Migratory Birds and Species at Risk

Husky has improved the protection of migratory birds through development of a Standard for Pre-Construction Migratory Bird Incidental Take Mitigation, as well as the preparation of a Bird Deterrent Guidance document to assist environmental staff and operators in the awareness and selection of the most appropriate deterrent systems for each facility. For Atlantic operations, in accordance with Husky's permit from the *Canadian Wildlife Service* ("**CWS**"), Husky's Seabird Handling Procedure provides guidance to personnel on how to handle birds that arrive on an installation. Oiled birds are cleaned and rehabilitated at Husky's Seabird Recovery Centre in consultation with CWS. Husky has improved protection of species at risk and their habitats by conducting environmental surveys and wildlife sweeps when appropriate to identify sensitive habitats, individuals and wildlife features (dens, for example) to allow implementation of appropriate mitigation measures.

Ice Management

Husky has several policies in place to protect people, equipment and the environment in the event of extreme weather conditions and adverse ice conditions. Husky has developed Adverse Weather Guidelines for the *SeaRose* FPSO and is managing physical risk through engineering for 1:100-year weather events.

Husky's Atlantic operations have a robust ice management program, which uses a range of resources including an industry-shared ice surveillance aircraft, as well as synergistic relationships with government agencies including Environment and Climate Change Canada, the Coast Guard and Canadian Ice Service. Regular ice surveillance flights commenced in February 2020 and continue until the risk has abated. In addition, Atlantic operators employ a series of supply and support vessels to actively manage ice and icebergs. These vessels are equipped with a variety of ice management tools including towing ropes, towing nets and water cannons. Husky also maintains a series of ad-hoc relationships with contractors, allowing the quick mobilization of additional resources as required.

Husky regularly assesses all aspects of its ice management program in order to ensure that the program continues to evolve as more information about the characteristics of ice and icebergs in the Atlantic becomes available and as new technologies are developed. Husky continues to look at ways to improve its ability to predict and respond to sea ice and icebergs with ongoing research and development. Recent initiatives include the design and fabrication of modular, heavy weather nets with sensors and development of a Common Operating Picture on Husky's contracted geographic information systems software module including ice flight information, location, drift models, and pack ice drift model runs. Husky now has a dedicated ice management room onshore, which mirrors the offshore and allows for real-time monitoring of field operations. Additional research and development activity related to ice management is continuing.

Abandonment, Reclamation and Remediation

Ongoing remediation and reclamation work is occurring at approximately 3,100 well sites and facilities in Western Canada. During 2019, Husky spent approximately $276 million on asset retirement obligations ("**ARO**") in North America and Husky expects to spend approximately $112 million in 2020 on ARO and environmental site closure activities in North America, including abandonment, decommissioning, reclamation and remediation.

Husky has also pioneered a program-based approach to asset retirement whereby all retirement activities are undertaken as a single program, greatly increasing the efficiency and effectiveness of the work. The Alberta Energy Regulator ("**AER**") has embraced Husky's approach, now referred to as "Area-Based Closure", has used it as a template for all of industry to adopt where possible and has incorporated it into its closure regulations.

In Asia Pacific and in accordance with the provisions of the regulations of the People's Republic of China, Husky has deposited funds into separate accounts restricted to the funding of future ARO. As at December 31, 2019, Husky had deposited funds of $142 million, which were classified as non-current liabilities.

Husky 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 17 of Husky's audited consolidated financial statements for the year ended December 31, 2019.

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 Upgrader.

Husky has several inactive facilities ranging from former refineries to retail locations. Management and remediation plans are prepared for these sites based on current and future land use.

Industry Collaboration Initiatives

Husky participates in 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.

Directly and through joint venture partnerships, Husky is a member of several industry associations that collaborate to identify and implement best practices on environmental performance. The International Petroleum Industry Environmental Conservation Association ("**IPIECA**"), the global oil and gas industry association for environmental and social issues, produces guidelines that Husky uses to improve its operations and environmental practices, enhance its strategic planning and engage with regulators. Through Husky's membership in Canada's upstream industry association, the Canadian Association of Petroleum Producers ("**CAPP**"), and the downstream industry association, the American Fuel and Petrochemical Manufacturers ("**AFPM**"), which represents the U.S. refining and petrochemicals industry. Husky enhances its ability to identify and address potential policy and regulatory risks to its business and participates in advocacy related activity to reduce those risks. Husky participates on the CAPP Board of Governors, as well as various Executive Policy Groups and working level groups and committees that focus on areas of policy or regulation that have been identified as areas of interest or impact to Husky's business. Husky participates in technology research for energy efficiency and emissions reduction through membership and participation in the Petroleum Technology Alliance Canada ("**PTAC**") and the Clean Resource Innovation Network ("**CRIN**"). In 2020, Husky joined Canada's Oil Sand Innovation Alliance ("**COSIA**"), whose purpose is to accelerate the pace of improvement in environmental performance in Canada's Oil Sands through collaborative action and innovations.

Husky is participating in IPIECA's Water Task Force and Climate Change Working Group as well as other topic-focused groups. Husky 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.

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

Husky holds memberships with, or participates in, the following sustainability groups and industry associations: Alberta Industrial Fire and Emergency Management Association, Allen County Environmental Citizen's Advisory Committee, Allen County Local Emergency Planning Committee, AFPM, Calgary Region Airshed Zone, COSIA, CAPP, Canadian Brownfields Network, Canadian Land Reclamation Association, Canadian Society for Unconventional Resources, Canadian Standards Association, Canadian Technical Asphalt Association, CDP, Center for Chemical Process Safety, an American Institute of Chemical Engineers Technological Community, China Offshore Environmental Services, China Offshore Oil Operation Safety Office Under Ministry of Emergency Management of the People's Republic of China, China's Marine Safety Administration, CHWMEG Inc., CRIN, Clearwater Mutual Aid CO-OP, Conference Board of Canada - Council on Emergency Management, Douglas County Local Emergency Planning Committee, Eastern Canada Response Corporation, Edson Mutual Aid Committee, Emergency Response Assistance Canada, Energy Safety Canada, Environmental Services Association of Alberta, Environmental Studies Research Funds, Foothills Research Institute, Foothills Stream Crossing Partnership, Hardisty Mutual Aid Plan, Indonesian Petroleum Association, Industrial Power Consumers Association of Alberta, Industry Footprint Reduction Operations Group, International Marine Contractors Association, International Oil & Gas Producers Association, IPIECA, Lakeland Industry and Community Association, Land Spill Emergency Program, Lima Area Security and Emergency Response Task Force, Lloydminster Emergency Preparedness Stakeholder Group, Mackenzie Delta Spill Response Corporation, Ministry of Ecology and Environment of the People's Republic of China, Monitoring Avian Productivity and Survivorship, Mutual Aid Alberta, Natural Sciences and Engineering Research Council FlareNet Network, North Saskatchewan Watershed Alliance, Ohio Chemistry Technology Council, Ohio Manufacturer's Association, Oil Companies International Marine Forum North American Regional Marine Forum, Oil Sand Monitoring, Oil Spill Response Limited, One Ocean, Orphan Well Association, Ottawa River Coalition, Parkland Airshed Management Zone, Petroleum Research Newfoundland and Labrador, PTAC, Red Deer Air Quality Advisory Group, RM Wood Buffalo Mutual Aid Group, Saskatchewan Environmental Industry and Managers Association, Saskatchewan Industrial Energy Consumers Association, Saskatchewan Petroleum Industry Government Environmental Committee, Shawnee Industrial Neighbors Group, Strathcona District Mutual Assistance Emergency Response Assistance, Agreement, Superior Petroleum Partners, Transportation Community Awareness and Emergency Response, Well Abandonment and Integrity Society, Western Canada Marine Response Corporation, Western Canadian Spill Services, Western Lake Superior Port Area Committee, Western Yellowhead Air Management Zone, and Wood Buffalo Environmental Association.

RISK FACTORS

The following summarizes what the Company believes to be the most significant risks relating to its operations which should be considered when purchasing securities of the Company. The Company has developed an enterprise risk matrix to identify risks to its people, the environment, its assets and its reputation, and to systematically mitigate these risks to an acceptable level. The risk matrix and associated mitigation strategies are reviewed quarterly by senior management and the Audit Committee, and annually by the Board.

Operational and Safety Incidents

The Company's businesses are subject to inherent operational risks which have the potential to impact safety, the environment, its assets and its reputation. In general, the Company's operations are subject to operational risks, including, but not limited to: fires, loss of containment, blowouts, power outages, freeze-ups and other similar events; oil and natural gas leaks; encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; uncontrollable flows of oil, natural gas and well fluids; spills at truck terminals and hubs; spills associated with the loading and unloading of potentially harmful substances onto trucks; release of tailings or harmful substances into a water system; the breakdown or failure of equipment, pipelines and facilities, information systems and processes; the performance of equipment at levels below those originally intended (whether due to misuse, unexpected degradation or design, construction or manufacturing defects); releases or spills from shipping vessels; failure to maintain adequate supplies of spare parts; the compromise of information technology and control systems and related data; operator error; labour disputes; disputes with interconnected facilities and carriers; operational disruptions or apportionment on third-party systems or refineries, which may prevent the full utilization of the company's facilities and pipelines; epidemics or pandemics; and catastrophic events, including, but not limited to, war, extreme weather events, natural disasters, explosions, acts of sabotage and other similar events.

Failure to manage the hazards and associated risks effectively could result in potential fatalities, environmental impacts, interruptions to activities or use of assets, or loss of license to operate. The Company, in accordance with industry practice, maintains insurance coverage against losses from certain of these risks. Nonetheless, insurance proceeds may not be sufficient to cover all losses, and insurance coverage may not be available for all types of operational risks.

Commodity Price Volatility.

The Company's results of operations and financial condition are dependent on the prices received for its refined products, crude oil, NGL and conventional natural gas production. Lower prices for crude oil, NGL and conventional natural gas could adversely affect the value and quantity of the Company's oil and gas reserves. The Company's reserves include significant quantities of heavier grades of crude oil that often 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 various grades of crude oil may be constrained from time to time, creating the need for additional refining and transportation capacity. Wider price differentials between heavier and lighter grades of crude oil could have a material adverse effect on the Company's results of operations and financial condition, reduce the value and quantities of the Company's heavier crude oil reserves and delay or cancel projects that involve the development of heavier crude oil resources. There is no guarantee that pipeline development projects or other transportation alternatives will provide sufficient transportation capacity and access to refining capacity to accommodate expected increases in North American heavy crude oil and bitumen production.

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

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

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

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. Due to the integrated nature, the Company has a natural partial mitigation to the WCS differential risk. 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 quarterly basis.

Reservoir Performance Risk

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

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

Restricted Market Access and Pipeline Interruptions

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

Security and Terrorist Threats

Security threats and terrorist or activist activities may impact the Company's personnel, which could result in injury, death, extortion, hostage situations and/or kidnapping, including unlawful confinement. A security threat, terrorist attack or activist incident targeted at a facility, office or offshore vessel/installation owned or operated by the Company could result in the interruption or cessation of key elements of the Company's operations. Outcomes of such incidents could have a material adverse effect on the Company's results of operations, financial condition and business strategy. The risk to employees and board members due to social unrest in Hong Kong is being managed through reduced travel and increased awareness and monitoring of the situation. The potential for detention and/or incarceration of the Company's employees/contractors entering into or working in China has increased, and as a result, review and reconsideration for travel into China has become a business/corporate process.

The Company does not own proved or probable reserves in or near areas of armed conflict. According to the Uppsala Conflict Data Program, armed conflict is defined as "contested incompatibility that concerns government and/or territory over which the use of armed force between the military forces of two parties, of which at least one is the government of a state, has resulted in at least 25 battle-related deaths each year."

International Operations

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

Major Project Execution

The Company manages a variety of oil and gas projects ranging from Upstream to Downstream assets across its global portfolio. The wide range of risks associated with project development and execution, as well as the commissioning and integration of new facilities with existing assets, can impact the economic viability of the Company's projects. Project risks may result in extended stakeholder consultation, additional environmental assessments and public hearings which may delay necessary environmental and regulatory approvals. Project risks may also manifest through schedule delays, cost overruns and commodity price drops. Some risks can impact the Company's safety and environmental records thereby negatively affecting the Company's reputation and social license to operate.

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

Partner Misalignment

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

Reserves Data, Future Net Revenue and Resource Estimates

The reserves data contained or referenced in this AIF represent estimates only. The accurate assessment of oil and gas reserves is critical to the continuous and effective management of the Company's Upstream assets. Reserves estimates support various investment decisions about the development and management of oil and gas properties. In general, estimates of economically recoverable crude oil and conventional natural gas reserves and the future net cash flow therefrom are based upon a number of variable factors and assumptions, such as product prices, future operating and capital costs, historical production from the properties and the effects of regulation by government agencies, including with respect to royalty payments, all of which may vary considerably from actual results. The Company uses all available information at the effective date of the evaluation and internal qualified reserves evaluators to prepare the reserves estimates. As required by NI 51-101, the Company obtains the opinion of an independent reserves auditor on the Company's reserves. The audit covers more than 75% of the future net revenue discounted at 10% attributable to proved plus probable reserves with the remainder reviewed by the independent qualified reserves auditor. However, given the best technical information and evaluation techniques, all such estimates are still to some degree uncertain. All reserves estimates involve a degree of ambiguity and, at times, rely on indirect measurement techniques to estimate the size and recoverability of the resource. While new technologies have increased the accuracy of these techniques, there remains the potential for human or systemic error in recording and reporting the magnitude of the Company's oil and gas reserves. Estimates of the economically recoverable oil and gas reserves attributable to any particular property or group of properties, and estimates of future net revenues expected therefrom, may differ substantially from actual results even though the total company reserves are shown to be reliable through the historical total company technical reserves revisions. The Company has a diverse portfolio of assets by product type, reservoir type and location which is a factor in mitigating specific property risks. Inaccurate appraisal of large project reservoirs could result in missed production, revenue and earnings targets and could have a material adverse effect on the Company's reputation, investor confidence and ability to deliver on its growth business strategy.

Government Regulation

Given the scope and complexity of the Company's operations, the Company is subject to regulations and interventions by governments at the federal, provincial, state and municipal levels in the countries in which it conducts its operations, development or exploratory activities. As these governments continually balance competing demands from different interest groups and stakeholders, the Company recognizes that the magnitude of regulatory risks has the potential to change over time. Changes in government policy, legislation or regulations 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, production restrictions, 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 Risks

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

The Company anticipates that further changes in environmental legislation could occur, which may result in stricter standards and enforcement, larger fines and liabilities, the introduction of emissions limits, increased compliance costs and approval delays for critical licences and permits. Public interest in ESG issues has also increased significantly in recent years, as evidenced by the large number of signatories to the United Nations Principles for Responsible Investment.

It is not possible to accurately forecast the amount of additional investment in new or existing facilities required in the future for environmental protection or to address all new regulatory compliance requirements, such as reporting. See "Industry Overview - Environmental Regulations" and "Environmental, Social and Governance Considerations - Environmental Protection".

Climate Change Risks

Regulatory

Climate change regulations may become more onerous over time as governments implement policies to further reduce GHG emissions. As these regulations continue to evolve, they could have a material adverse effect on the Company's competitiveness, financial condition and results of operations through increased capital and operating costs and change in demand for refined products such as transportation fuels. Costs associated with levy payments for emerging climate change regulations may be significant.

In December 2018, the Government of Canada published the Regulatory Design Paper on the CFS that focuses on the liquid fuel stream regulations. A Proposed Regulatory Approach for the CFS was published in June 2019 and proposed regulations are expected to be published in Canada Gazette, Part I for early 2020. The final regulations for liquid fuels are planned for early 2021, with the regulations expected to come into force in 2022. Due to the uncertainty of the gaseous and solid fuel regulations, the full impact of the CFS is still unknown.

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

The Company complies with the RFS program in the U.S. by blending renewable fuels manufactured by third parties and by purchasing RINs on the open market. 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 have been volatile. 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 compliance costs on to its customers and if the Company pays significantly higher prices for RINs or blendstocks to comply with the RFS mandated standards.

Climatic Conditions

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

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

Transition

In addition to emissions regulations and the physical risks of climate change, climate-related transition risks could have a material adverse effect on the Company's business, financial condition and results of operations, and could adversely impact the Company's reputation. For example, increased public opposition to companies in the oil sands industry could lead to constrained access to insurance, liquidity and capital and changes in demand for the Company's products, which may impact revenue. Any increases in GHG emissions by the Company could lead to additional taxes and levies, which would increase the costs associated with certain projects. The potential need to develop new technologies to reduce the intensity of GHG emissions could require significant capital investment. Further, the Company may become subject to climate change litigation initiated by third parties. The Company's management monitors these risks and reports to the Board through management's Enterprise Risk Management framework.

Overall, the Company is not able to estimate at this time the degree to which climate change related regulatory, climatic conditions, and transition risks could impact the Company's financial and operating results.

Foreign Currency

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

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

Interest Rate

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

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

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

Debt Covenants

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

Competition

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

Credit Rating Risk

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

General Economic Conditions

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

Cost or Availability of Oil and Gas Field Equipment

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

Financial Controls

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

Cybersecurity Threats

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

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

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

Skilled Workforce Attraction and Retention

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

Aviation Incidents

The Company's Offshore operations in Canada and China rely on regular travel by helicopter. A helicopter incident resulting in loss of life, facility shutdown or regulatory action could have a material adverse effect on the operations of the Company. This risk is managed through an aviation management process. Aviation Safety Reviews are conducted by third party specialist contractors to verify that helicopter service providers meet the Company's and industry standards with respect to aviation safety. The reviews include evaluation of aircraft type, effectiveness of the safety and maintenance management systems and competency and training programs for critical roles in the operation of helicopters. Helicopters chartered to support Husky Offshore operations must be fit for service and as such are fitted with multiple redundant systems to address a wide range of potential in-flight emergencies. Additional measures specific to the Company's challenging operating environments are specified in the Company's design requirements including anti-icing and floatation systems effective for the maximum allowable sea height operating limits. Pilots are trained to address potential emergency situations through regular real-time and simulator training aligned with industry best practice.

HUSKY EMPLOYEES

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

	As at December 31,		
	2019	2018	2017
Number of permanent employees	**4,802**	5,157	5,152

DIVIDENDS

Dividend Amounts

The following table shows the aggregate amount of the dividends declared payable per share in respect of its last three financial 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:

	2019	2018	2017
Dividends per Common Share	**$ 0.50**	$ 0.45	$ 0.08
Dividends per Series 1 Preferred Share	**$ 0.60**	$ 0.60	$ 0.60
Dividends per Series 2 Preferred Share	**$ 0.85**	$ 0.74	$ 0.57
Dividends per Series 3 Preferred Share	**$ 1.13**	$ 1.13	$ 1.13
Dividends per Series 5 Preferred Share	**$ 1.13**	$ 1.13	$ 1.13
Dividends per Series 7 Preferred Share	**$ 1.15**	$ 1.15	$ 1.15

Dividend Policy and Restrictions

The declaration and payment of dividends are at the discretion of the Board, 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

On February 28, 2018, the Board reinstated the quarterly common share cash dividend of $0.075 per share. On July 26, 2018, the Board increased the quarterly common share cash dividend to $0.125 per share.

The Board has the ability to declare 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.

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

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% annually for the initial period ending March 31, 2016, as and when declared by the Board. Thereafter, the dividend rate will be reset every five years at a rate equal to the five-year Government of Canada bond yield plus 1.73%. 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% 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 on March 31 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% as and when declared by the Board. Effective March 31, 2016, Husky had 1,564,068 Series 2 Shares issued and outstanding. Holders of the Series 2 Shares have the right, at their option, to convert their shares into Series 1 Preferred Shares, subject to certain conditions, on March 31, 2021, and on March 31every 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% 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%. Holders of Series 3 Shares had the right, at their option, to convert their shares into Series 4 Preferred Shares, subject to certain conditions, on December 31, 2019. In the fourth quarter of 2019, Husky announced it did not intend to exercise its right to redeem the Series 3 Preferred Shares on December 31, 2019. As a result, the holders of the Series 3 Preferred Shares had the right to choose to retain any or all of their Series 3 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 3 Preferred Shares into Series 4 Preferred Shares, and receive a floating rate quarterly dividend. Holders of the Series 3 Preferred Shares who retained their shares will receive the new fixed rate quarterly dividend applicable to the Series 3 Preferred Shares of 4.689% for the five-year period commencing December 31, 2019 to, but excluding, December 31, 2024. Effective December 31, 2019, Husky had 10,000,000 Series 3 Preferred Shares issued and outstanding and no Series 4 Preferred Shares were issued due to conditions for the conversion into Series 4 Preferred Shares not being satisfied. Holders of the Series 3 Preferred Shares will have the opportunity to convert their shares again on December 31, 2024, and on December 31 every five years thereafter as long as the shares remain outstanding.

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% annually for the initial period ending March 31, 2020 as declared by the Board. 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%. 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%.

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% annually for the initial period ending June 30, 2020 as declared by the Board. 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%. 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%.

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 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 declares a dividend on the common shares payable in whole or in part as a stock dividend, unless otherwise determined by the Board in respect of a particular dividend, the value of the common shares for purposes of each stock dividend declared by the Board 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.

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 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 is entitled to vote, except in accordance with the provisions of the *Business Corporations Act* (Alberta).

Husky may, at its option, redeem all or any number of the then outstanding Series 1 Preferred Shares, subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 2 Preferred Shares, subject to certain conditions, on March 31, 2021 and on March 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 3 Preferred Shares, subject to certain conditions, on December 31, 2024 and on December 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 5 Preferred Shares, subject to certain conditions, on March 31, 2020 and on March 31 every five years thereafter. Husky may, at its option, redeem all or any number of the then outstanding Series 7 Preferred Shares, subject to certain conditions, on June 30, 2020 and on June 30 every five years thereafter.

Liquidity Summary

Overview

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

	Standard and Poor's Rating Services ("S&P")	Moody's Investor Service ("Moody's")	Dominion Bond Rating Services Limited ("DBRS")
Outlook/Trend	Stable	Stable	Stable
Senior Unsecured Debt	BBB	Baa2	A(low)
Series 1 Preferred Shares	P-3(high)		Pfd-2(low)
Series 2 Preferred Shares	P-3(high)		Pfd-2(low)
Series 3 Preferred Shares	P-3(high)		Pfd-2(low)
Series 5 Preferred Shares	P-3(high)		Pfd-2(low)
Series 7 Preferred Shares	P-3(high)		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 S&P, Moody's and DBRS. 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 (S&P) long-term credit ratings are on a rating scale that ranges from AAA (highest) to D (lowest). A rating of BBB by S&P is within the fourth highest of 10 categories and indicates that the obligation exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The addition of a plus (+) or minus (-) designation after a rating indicates the relative standing within the major rating categories.

S&P 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 S&P's ratings scale for long-term credit ratings. According to S&P's ratings system, a P-3 (high) rating on the Canadian preferred share rating scale is equivalent to a BB+ rating on the long-term credit rating scale. A rating of BB by S&P is within the fifth highest of 10 categories and indicates that the obligation is less vulnerable to nonpayment than other speculative issues. However, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions that could lead to the obligor's inadequate capacity to meet its financial commitments on the issue.

Dominion Bond Rating Service

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

DBRS 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. DBRS preferred share ratings range from Pdf-1 (highest) to D (lowest). According to the DBRS' 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.

DBRS 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 quality. A rating of R-1 (low) by DBRS 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 March 31, 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, 2019:

	High	Low	Volume (000's)
January	18.05	13.48	56,599
February	16.02	14.50	32,088
March	14.98	13.24	51,931
April	14.90	13.21	34,792
May	14.62	12.31	32,484
June	13.03	12.18	55,149
July	12.77	9.78	39,416
August	10.18	8.48	43,124
September	10.21	8.61	51,942
October	9.69	8.56	40,615
November	10.56	9.25	67,520
December	10.79	9.26	48,754

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, 2019:

	High	Low	Volume (000's)
January	14.15	13.01	96
February	14.46	13.05	153
March	13.77	12.49	107
April	13.25	12.40	48
May	13.00	12.00	164
June	13.30	12.01	384
July	13.26	12.01	275
August	12.60	10.13	95
September	11.99	10.93	113
October	11.32	10.46	120
November	11.99	10.73	222
December	12.45	10.48	558

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, 2019:

	High	Low	Volume (000's)
January	14.99	13.74	16
February	14.63	13.93	7
March	14.20	13.00	18
April	13.50	13.10	5
May	13.96	13.00	20
June	13.01	12.37	8
July	13.24	12.85	10
August	13.00	11.24	29
September	11.93	11.20	26
October	11.50	10.98	97
November	12.00	11.02	45
December	12.40	10.90	50

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, 2019:

	High	Low	Volume *(000's)*
January	20.39	18.76	75
February	20.47	18.05	174
March	19.60	18.07	145
April	18.99	18.40	128
May	18.97	17.50	216
June	18.67	17.80	164
July	19.22	18.15	146
August	18.20	15.45	154
September	17.15	16.00	470
October	16.57	15.70	301
November	17.35	16.08	260
December	17.47	16.10	253

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, 2019:

	High	Low	Volume *(000's)*
January	21.50	19.38	129
February	21.65	19.06	188
March	20.41	19.30	164
April	20.75	19.50	99
May	20.88	18.99	137
June	20.20	18.81	147
July	20.46	19.35	96
August	19.21	16.30	111
September	18.52	16.79	246
October	18.17	16.92	118
November	18.60	17.30	162
December	19.00	17.06	294

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, 2019:

	High	Low	Volume *(000's)*
January	21.21	19.75	159
February	21.70	19.30	56
March	20.00	19.25	180
April	20.47	19.40	325
May	20.40	18.90	62
June	19.96	18.50	94
July	20.13	19.08	97
August	19.32	15.85	196
September	18.24	17.00	134
October	17.70	16.90	64
November	18.87	17.17	69
December	19.00	16.90	96

DIRECTORS AND OFFICERS

Directors

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

Name & Residence	Office or Position	Principal Occupation During Past Five Years
Li, Victor T. K. Hong Kong Special Administrative Region	Co-Chair of the Board Director since August 2000	Mr. Li is the Chairman and Group Co-Managing Director of CK Hutchison Holdings Limited. He is also the Chairman and Managing Director of CK Asset Holdings Limited. He is also the Chairman and Executive Director of CK 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 and Li Ka Shing (Global) Foundation (formerly known as Li Ka Shing (Overseas) Foundation), Member Deputy Chairman of 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 Chief Executive's Council of Advisers on Innovation and Strategic Development of the Hong Kong Specia 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 of the Board and Chair of the Compensation Committee	Mr. Fok is an Executive Director and Group Co-Managing Director of CK Hutchison Holdings Limited.
	Director since August 2000	Mr. Fok is Chairman and a Director of Hutchison Telecommunications Hong Kong Holdings Limited, Hutchison Telecommunications (Australia) Limited, Hutchison Port Holdings Management Pte. Limited as the trustee-manager of Hutchison Port Holdings Trust, Power Assets Holdings Limited, HK Electric Investments Manager Limited as the trustee-manager of HK Electric Investments, and HK Electric Investments Limited. Mr. Fok is Deputy Chairman and an Executive Director of CK Infrastructure Holdings Limited. 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. Hong Kong Special Administrative Region	Member of the Audit Committee and the Corporate Governance Committee	Mr. Bradley is a Director of Broadlea Group Ltd., Senior Consultant, NEX Group plc (formerly known as ICAP (Asia Pacific) Ltd.).
	Director 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 holds an Institute of Corporate Directors designation (ICD.D).
Ghosh, Asim London, United Kingdom	Member of the Health, Safety and Environment Committee	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.
	Director since May 2009	Mr. Ghosh was the Managing Director and Chief Executive Officer of Vodafone Essar Limited (a telecommunications company) from August 1998 until March 2009. From 1991 to 1998 he held senior executive positions and then the position of Chief Executive Officer of the A S Watson Industries subsidiary (a manufacturer of consumer goods) of Hutchison Whampoa Limited. Prior thereto from 1989, Mr. Ghosh was the Chief Executive Officer of the Pepsi Foods (Frito Lay) start up in India. Mr. Ghosh began his career with Proctor & Gamble in Canada in 1971 and subsequently worked with Rothmans International in what was then its Carling O'Keefe subsidiary from 1980 to 1988, his last position being Senior Vice President of the brewery operations. Mr. Ghosh was Chairman of the Cellular Operators Association of India and of the National Telecom Committee of the Confederation of Indian Industries. He was an independent Director of Kotak Bank, a listed Indian Bank until 2016, and was on the Board of Directors of Vodafone Essar Limited until February 2010. 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 Member of the Audit Committee and the Compensation Committee	Mr. Glynn is a Director and Chair of Public Sector Pension Investment Board (PSP Investments), and a Director of Sun Life Financial Inc. and Sun Life Assurance Company of Canada.
	Director 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 in 1974 and a Master's degree in Business Administration from the University of British Columbia in 1976.

Koh, Poh Chan Hong Kong Special Administrative Region	Director since August 2000	Ms. Koh is Finance Director of Harbour Plaza Hotel Management (International) Ltd. (a hotel management company) and also a Member of the Executive Committee of CK Asset Holdings Limited. Ms. Koh is qualified as a Fellow Member (FCA) of the Institute of Chartered Accountants in England and Wales and is an Associate of the Canadian Institute of Chartered Accountants (CPA, CA) and the Chartered Institute of Taxation in the U.K. (CTA). Ms. Koh graduated from the London School of Accountancy in 1971 and was admitted to the Institute of Chartered Accountants in England and Wales in 1973, to the Chartered Institute of Taxation in the UK in 1976 as well as the Institute of Chartered Accountants of Ontario, Canada in 1980.
Kwok, Eva L. British Columbia, Canada	Member of the Compensation Committee and the Corporate Governance Committee	Mrs. Kwok is Chairman, a Director and Chief Executive Officer of Amara Holdings Inc. (a private investment holding company). Mrs. Kwok is also a Director of CK Life Sciences Int'l., (Holdings) Inc. and CK Infrastucture Holdings Limited. Mrs. Kwok is also a Director of the Li Ka Shing (Canada) Foundation.
	Director since August 2000	Mrs. Kwok was a Director of Shoppers Drug Mart Corporation from 2004 to 2006 and of the Bank of Montreal Group of Companies from 1999 until March 2009. Mrs. Kwok obtained a Master's degree in Science from the University of London in 1967.
Kwok, Stanley T. L. British Columbia, Canada	Member of the Health, Safety and Environment Committee	Mr. Kwok is a Director and President of Amara Holdings Inc. He is an independent Non-Executive Director of CK Hutchison Holdings Limited.
	Director since August 2000	Mr. Kwok is a Director of Element Lifestyle Retirement Inc. He retired as a Director of the CTBC Bank of Canada in July, 2018. 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 was born and educated in Hong Kong. He graduated with a Bachelor of Arts (Honours) degree from The University of Hong Kong in 1973, having majored in economics and history. After graduation, he filled various senior positions at local and overseas banks, financial institutions and major companies, including Chase Manhattan Bank, Royal Bank of Canada Dominion Securities, JP Morgan Chase, Kumagai Gumi (HK) Limited and Pacific Century Cyberworks Limited.
	Director since July 2010	In 2002, he joined the Hong Kong SAR Government as Secretary for Financial Services and the Treasury, and assumed the post of Secretary for Commerce and Economic Development in 2007. He resigned in July 2008 due to medical reasons. In October 2008, he was appointed Honorary Professor of the School of Economics and Finance at The University of Hong Kong. Professor Ma was appointed Member of the International Advisory Council of the China Investment Corporation in July 2009. In December 2011, he was appointed Honorary President of Hong Kong Special Schools Council. In January 2013, he was appointed Member of the Global Advisory Council of the Bank of America. In August of that year, he was appointed Honorary Professor of the Faculty of Business Administration at The Chinese University of Hong Kong. In October 2014, he was conferred Honorary Doctor of Social Sciences by Lingnan University, and in October 2016 he received the same honour from City University of Hong Kong. In April 2017, he was appointed as the Council Chairman of The Education University of Hong Kong in 2017. In March 2018, he was appointed as a Member of the Chief Executive's Council of Advisers on Innovation and Strategic Development. He is currently an Independent Non-Executive Director of the FWD Group and a Director of New Frontier Corporation.

Magnus, George C. Hong Kong Special Administrative Region	Member of the Audit Committee Director since July 2010	Mr. Magnus is a Non-Executive Director of CK Hutchison Holdings Limited and CK Infrastructure Holdings Limited, 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. 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 Holdings Limited from 2005 to 2012 and then an independent Non-Executive Director until January 2014. Mr. Magnus obtained a Bachelor of Arts degree in 1959. He obtained a Master's degree in Economics from King's College, Cambridge University in 1963.
McGee, Neil D. Luxembourg	Member of the Health, Safety and Environment Committee Director since November 2012	Mr. McGee is the Managing Director of Hutchison Whampoa Europe Investments S.à r.l. He is an Executive Director of Power Assets Holdings Limited. Prior to his joining Hutchison Whampoa Europe Investments S.à r.l., he served as Group Finance Director of Power Assets Holdings Limited from 2006 to 2012, Chief Financial Officer of Husky Oil Limited from 1998 to 2000 and Chief Financial Officer of Husky Energy Inc. from 2000 to 2005. Prior to joining Husky Oil Limited in 1998, Mr. McGee held various financial, legal and corporate secretarial positions with the CK Hutchison Holdings Group. Mr. McGee holds a Bachelor of Arts degree and a Bachelor of Laws degree from the Australian National University.
Peabody, Robert J. Alberta, Canada	President & Chief Executive Officer Director since December 2016	Mr. Peabody became a member of the Board of Directors and President and Chief Executive Officer of Husky on December 5, 2016. Mr. Peabody was appointed Chief Operating Officer in 2006 and was responsible for leading Husky's Upstream and Downstream segments, including Western Canada Conventional and Unconventional, Heavy Oil, Oil Sands, Atlantic Region and Exploration, as well as Refining and Upgrading operations. He was also responsible for the Safety, Engineering, Project Management and Procurement functions. Prior to joining Husky, he led four major businesses for BP plc in Europe and the United States. Mr. Peabody holds a Bachelor of Science degree in Mechanical Engineering from the University of British Columbia and a Master of Science degree in Management (Sloan Fellow) from Stanford University. Mr. Peabody is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA) and Vice-Chairman of the Foothills Hospital Development Council.

Russel, Colin S. Gloucestershire, United Kingdom	Chair of the Health, Safety and Environment Committee and member of the Audit Committee Director since February 2008	Mr. Russel is the founder and a Director of Emerging Markets Advisory Services Ltd. (a business advisory company). Mr. Russel is a Director of CK Infrastructure Holdings Limited, CK Life Sciences Int'l., (Holdings) Inc. and ARA Asset Management Pte. Ltd. Mr. Russel was the Canadian Ambassador to Venezuela; Consul General for Canada in Hong Kong; Director for China of the Department of Foreign Affairs, Ottawa; Director for East Asian Trade in Ottawa; Senior Trade Commissioner for Canada in Hong Kong; Director for Japan Trade in Ottawa and was in the Trade Commissioner Service for Canada in Spain, Hong Kong, Morocco, the Philippines, London and India. Previously Mr. Russel was an international project manager with RCA Ltd., Canada and development engineer with AEI Ltd., UK. Mr. Russel received a degree in Electrical Engineering in 1962 and a Master's degree in Business Administration in 1971, both from McGill University, Canada.
Shaw, Wayne E. Ontario, Canada	Member of the Audit Committee and the Corporate Governance Committee, and the Health, Safety and Environment Committee	Mr. Shaw is the President of G.E. Shaw Investments Limited. Prior to his retirement in April 2013, he was a Senior Partner with Stikeman Elliott LLP,Barristers and Solicitors. Mr. Shaw is also a Director of the Li Ka Shing (Canada) Foundation.
	Director 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 of the Board and Chair of the Audit Committee Director since August 2000	Mr. Shurniak was an independent Non-Executive Director of Hutchison Whampoa Limited until June 2015, when he became an independent Non-Executive Director of CK Hutchison Holdings Limited. From May 2005 to June 2011 he was a Director and Chairman of Northern Gas Networks Limited (a private distributor of natural gas in Northern England). Mr. Shurniak also held the following positions until his return to Canada in 2005: Director and Chairman of ETSA Utilities (a utility company) since 2000, Powercor Australia Limited (a utility company) since 2000, CitiPower Pty Ltd. (a utility company) since 2002, and a Director of Envestra Limited (a natural gas distributor) since 2000, CrossCity Motorways Pty Ltd. (an infrastructure and transportation company) since 2002 and Lane Cove Tunnel Company Pty Ltd. (an infrastructure and transportation company) since 2004. Mr. Shurniak has broad banking experience and he holds Honorary Doctor of Laws degrees from the University of Saskatchewan, the University of Western Ontario and the University of Regina. He was a recipient of the Saskatchewan Centennial Medal from the Lieutenant Governor of Saskatchewan in 2005 and the Saskatchewan Order of Merit by the Government of the Province of Saskatchewan in 2009. He was awarded the Queen Elizabeth II Diamond Jubilee Medal by the Lieutenant Governor of Saskatchewan in 2012, and the Meritorious Service Medal by the Governor General of Canada in 2016.

Sixt, Frank J. Hong Kong Special Administrative Region	Member of the Compensation Committee Director since August 2000	Mr. Sixt is an Executive Director, Group Finance Director and Deputy Managing Director of CK Hutchison Holdings Limited. Mr. Sixt is also the Non-Executive Chairman of TOM Group Limited, an Executive Director of CK Infrastructure Holdings Limited, a Director of Hutchison Telecommunications (Australia) Limited (HTAL) and an Alternate Director to a Director of HTAL, HK Electric Investments Manager Limited as the trustee-manager of HK Electric Investments and HK Electric Investments Limited. Mr. Sixt is also a Director of the Li Ka Shing (Canada) Foundation. Mr. Sixt obtained a Master's degree in Arts from McGill University, Canada in 1978 and a Bachelor's degree in Civil Law from Université de Montréal in 1978. He is a member of the Bar and of the Law Society of the Provinces of Quebec and Ontario, Canada.

Officers

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

Name and Residence	Office or Position	Principal Occupation During Past Five Years
Li, Victor T. K. Hong Kong Special Administrative Region	Co-Chair of the Board	Group Co-Managing Director and Deputy Chairman of CK Hutchison Holdings Limited; Managing Director and Deputy Chairman of CK Asset Holdings Limited (formerly known as Cheung Kong Property Holdings Limited); Chairman and Executive Director of CK Infrastructure Holdings Limited (formerly known as Cheung Kong Infrastructure Holdings Limited) and CK Life Sciences Int'l., (Holdings) Inc.; a Non-Executive Director of Power Assets Holdings Limited and HK Electric Investments Manager Limited which is the trustee-manager of HK Electric Investments; and a Non-Executive Director and the Deputy Chairman of HK Electric Investments Limited.
Fok, Canning K. N. Hong Kong Special Administrative Region	Co-Chair of the Board	Executive Director and Group Co-Managing Director of CK Hutchison Holdings Limited; 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; and Deputy Chairman and an Executive Director of CK Infrastructure Holdings Limited (formerly known as Cheung Kong Infrastructure Holdings Limited).
Shurniak, William Saskatchewan, Canada	Deputy Chair of the Board	Deputy Chair of the Board since August 2000.
Peabody, Robert J. Alberta, Canada	President & Chief Executive Officer	President & Chief Executive Officer of Husky since December 2016. Chief Operating Officer of Husky from April 2006 to December 2016.
Hart, Jeffrey R. Alberta, Canada	Chief Financial Officer	Chief Financial Officer of Husky since November 2018. Acting Chief Financial Officer of Husky from April 2018 to November 2018. Vice President, Controller of Husky from February 2015 to April 2018.
Symonds, Robert W. P. Alberta, Canada	Chief Operating Officer	Chief Operating Officer of Husky since March 2017. Senior Vice President, Western Canada Production of Husky Oil Operations Limited from April 2012 to March 2017.
Girgulis, James D. Alberta, Canada	Senior Vice President, General Counsel & Secretary	Senior Vice President, General Counsel & Secretary since April 2012. Vice President, Legal & Corporate Secretary of Husky from August 2000 to April 2012.

As at February 15, 2020, the directors and executive officers of Husky, as a group, beneficially owned or controlled or directed, directly or indirectly, 944,844.08 common shares of Husky, representing less than 1% of the issued and outstanding common shares.

Conflicts of Interest

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

Corporate Cease Trade Orders or Bankruptcies

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

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

Individual Penalties, Sanctions or Bankruptcies

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

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

AUDIT COMMITTEE

Composition

The members of Husky's Audit Committee (the "**Committee**") are William Shurniak (Chair), Stephen E. Bradley, Martin J.G. Glynn, Frederick S. H. Ma, George C. Magnus, Colin S. Russel and Wayne E. Shaw. Each of the members of the Committee is independent in that each member does not have a direct or indirect material relationship with the Company. Multilateral Instrument 52-110 *Audit Committees* provides that a material relationship is a relationship which could, in the view of the Board, 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., and Senior Consultant NEX Group plc (formerly known as ICAP (Asia Pacific) Ltd.).

Martin J. G. Glynn - Mr. Glynn is the Chairman and a Director of the Public Sector Pension Investment Board and a Director of Sun Life FInancial Inc. and Sun Life Assurance Company of Canada. Mr. Glynn was a Director from 2000 to 2006 and President and Chief Executive Officer of HSBC Bank USA N.A. from 2003 until his retirement in 2006. Mr. Glynn was a Director of HSBC Bank Canada from 1999 to 2006 and President and Chief Executive Officer from 1999 to 2003.

Frederick S. H. Ma - Professor Ma has held senior management positions in international financial institutions and Hong Kong publicly listed companies. He has also 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 CK Infrastructure Holdings Limited, and an independent Non-Executive Director of HK Electric Investments Manager Limited.

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

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

The Committee Mandate is attached hereto as Appendix A.

External Auditor Service Fees

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

($ thousands)	**2019**	2018
Audit Fees	**4,133**	3,612
Audit-related Fees	**235**	249
Tax Fees	**283**	226
	4,651	4,087

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 2019.

LEGAL PROCEEDINGS

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

None of the Company's directors, executive officers or persons or companies that beneficially own or control or direct, directly or indirectly or a combination of both, more than 10% 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, reviewed and opined upon as at December 31, 2019 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 1% of the Company's securities of any class.

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

ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration, principal shareholders of Husky's common shares and a description of options to purchase common shares is contained in Husky's Management Information Circular prepared in connection with the annual meeting of shareholders held on April 26, 2019.

Additional financial information is provided in Husky's audited consolidated financial statements and management's discussion and analysis ("**MD&A**") for the financial year ended December 31, 2019.

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

READER ADVISORIES

Forward-looking Statements

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

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

- with respect to the business, operations and results of the Company generally: the Company's general strategic plans and growth strategies; expected effects of abandonment and reclamation costs, development costs and operating costs on anticipated development or production activities on properties with attributed reserves and 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, 2019; the Company's 2020 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 thermal developments in the Integrated Corridor: estimated production and expected timing of first production from the Spruce Lake Central, Spruce Lake North, Spruce Lake East, Edam Central and Dee Valley 2 projects; plans to drill two new sustainment pads, and timing for a major plant turnaround, at the Tucker Thermal Project; and timing for a turnaround on Plant 1B at the Sunrise Energy Project;

- with respect to the Company's Western Canada operations in the Integrated Corridor: strategic and drilling plans; and timing to complete the sale of certain assets in the Hussar area;

- with respect to the Company's infrastructure and marketing business in the Integrated Corridor: growth projects for HMLP; and the expansion of the Hardisty terminal;

- with respect to the Company's Canadian refined products business in the Integrated Corridor, the potential sale of the Canadian Retail and Commercial Fuels Network;

- with respect to the Company's U.S. refining and marketing business in the Integrated Corridor: the expected timing of ramp-up to full rates at the Lima Refinery; the expected timeframe, and investment, for the rebuild of the Superior Refinery and the timing that operations will resume; and anticipation that a substantial portion of the investment to rebuild the Superior Refinery will be recovered from property damages insurance and that lost income through April 2020 will be compensated by business interruption insurance;

- with respect to the Company's Offshore business in Asia Pacific: the expected timing of construction of, and first gas production from, Liuhua 29-1; target production from Liuhua 29-1 when fully ramped up; drilling plans for Block 15/33; the expected timing of drilling five MDA field production wells and two MBH field production wells, and the expected timing of first gas production and sales therefrom; timing for the development of a floating production unit at MDA and MBH; and the expected timing of development and tie-in of the additional MDK shallow water field; and

- with respect to the Company's Offshore business in Atlantic, development and construction plans, expected timing of first oil and expected volume and timing of peak production, at the West White Rose Project.

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

Although the Company believes that the expectations reflected by the forward-looking statements presented in this AIF are reasonable, the Company's forward-looking statements have been based on assumptions and factors concerning future events that may prove to be inaccurate. Those assumptions and factors are based on information currently available to the Company about itself and the businesses in which it operates. Information used in developing forward-looking statements has been acquired from various sources, including third party consultants, suppliers and regulators, among others. The material factors and assumptions used to develop the forward-looking statements include, but are not limited to:

- with respect to the business, operations and results of the Company generally: the absence of significant adverse changes to commodity prices, interest rates, applicable royalty rates and tax laws, and foreign exchange rates; the absence of significant adverse changes to energy markets, competitive conditions, the supply and demand for crude oil, natural gas, NGL and refined petroleum products, or the political, economic and social stability of the jurisdictions in which the Company operates; continuing availability of economical capital resources, labour and services; demand for products and cost of operations; the absence of significant adverse legislative and regulatory changes, in particular changes to the legislation and regulation governing fiscal regimes and environmental issues; and stability of general domestic and global economic, market and business conditions;

- with respect to the Company's Offshore business in Asia Pacific and Atlantic and upstream operations in the Integrated Corridor (including the infrastructure and marketing and Canadian refined products businesses): the accuracy of future production rates and reserve estimates; the securing of sales agreements to underpin the commercial development and regulatory approvals for the development of the Company's properties; the absence of significant delays in the procurement, development, construction or commissioning of the Company's projects, for which the Company or a third party is the designated operator, that may result from the inability of suppliers to meet their commitments, lack of regulatory or third-party approvals or other governmental actions, harsh weather or other calamitous event; the absence of significant disruption of operations such as may result from harsh weather, natural disaster, accident, civil unrest or other calamitous event; the absence of significant unexpected technological or commercial difficulties that adversely affect exploration, development, production, processing or transportation; the sufficiency of budgeted capital expenditures in carrying out planned activities; and the absence of significant increases in the cost of major growth projects; and

- with respect to the Company's downstream operations in the Integrated Corridor: the absence of significant delays in the development, construction or commissioning of the Company's projects that may result from the inability of suppliers to meet their commitments, lack of regulatory or third-party approvals or other governmental actions, harsh weather or other calamitous event; the absence of significant disruption of operations such as may result from harsh weather, natural disaster, accident, civil unrest or other calamitous event; the absence of significant unexpected technological or commercial difficulties that adversely affect processing or transportation; the sufficiency of budgeted capital expenditures in carrying out planned activities; and the absence of significant increase in the cost of major growth projects.

Because actual results or outcomes could differ materially from those expressed in any forward-looking statements, investors should not place undue reliance on any such forward-looking statements. By their nature, forward-looking statements involve numerous assumptions, inherent risks and uncertainties, both general and specific, which contribute to the possibility that the predicted outcomes will not occur. Some of these risks, uncertainties and other factors are similar to those faced by other oil and gas companies and some are unique to Husky. The risks, uncertainties and other factors, many of which are beyond Husky's control, that could cause actual results to differ (potentially significantly) from those expressed in the forward-looking statements include, but are not limited to:

- with respect to the business, operations and results of the Company generally: those risks, uncertainties and other factors described under "Risk Factors" in this AIF and throughout the Company's MD&A for the year ended December 31, 2019; 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 gas and liquids sales agreements which are denominated in Chinese Yuan; the ability to replace reserves of oil and gas, whether sourced from exploration, improved recovery or acquisitions; potential actions of governments, regulatory authorities and other stakeholders that may impose operating costs or restrictions in the jurisdictions where the Company has operations; changes to royalty regimes; changes to government fiscal, monetary and other financial policies; changes in workforce demographics; and the cost and availability of capital, including access to capital markets at acceptable rates;

- with respect to the Company's Offshore business in Asia Pacific and Atlantic and upstream operations in the Integrated Corridor (including the infrastructure and marketing and Canadian refined products businesses): 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 operations in the Integrated Corridor: 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, 2019, which is 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.

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

Non-GAAP Measures

This AIF contains the term "operating netback", which is a common non-GAAP metric used in the oil and gas industry and is not used to enhance the Company's reported financial performance or position. Management believes this measure assists management and investors to evaluate the specific operating performance by product at the oil and gas lease level. Operating netback is calculated as gross revenue less royalties, production and operating and transportation costs on a per unit basis.

This AIF contains the term "funds from operations", which is a non-GAAP measure that does not have a standardized meaning prescribed by IFRS and therefore is unlikely to be comparable to similar measures presented by other issues. It is common in the reports of other companies but may differ by definition and application. Funds from operations should not be considered an alternative to, or more meaningful than, "cash flow - operating activities" as determined in accordance with IFRS, as an indicator of financial performance. Funds from operations equals cash flow - operating activities excluding change in non-cash working capital. Management believes that impacts of non-cash working capital items on cash flow - operating activities may reduce comparability between periods, accordingly, funds from operations is presented in the Company's financial reports to assist management and investors in analyzing operating performance of the Company in the stated period compared to prior periods.

Disclosure of Oil and Gas Information

Unless otherwise indicated: (i) reserves estimates have been prepared by internal qualified reserves evaluators in accordance with the Canadian Oil and Gas Evaluation Handbook, has been audited and reviewed by Sproule, an independent qualified reserves auditor, have an effective date of December 31, 2019 and represent the Company's working interest share (ii) projected and historical production volumes quoted are gross, which represents the total or the Company's working interest, as applicable share before deduction of royalties (iii) all Husky working interest production volumes quoted are before deduction of royalties; and (iv) historical production volumes provided are for the year ended December 31, 2019.

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

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

This document includes an estimate of net pay thickness at White Rose A-78, which estimate may be considered to be anticipated results under NI 51-101. The estimate was prepared internally. The risks and uncertainties associated with recovery of resources from A-78 include, but are not limited to: that Husky may encounter unexpected drilling results; the occurrence of unexpected events in the exploration for, and the operation and development of, oil and gas; delays in anticipated timing of drilling and completion of wells; geological, technical, drilling and processing problems; and other difficulties in producing petroleum reserves.

Note to U.S. Readers

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

All currency is expressed in Canadian dollars unless otherwise directed.

Appendix A

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 Independent Qualified Reserves Auditor

To the board of directors of Husky Energy Inc. (the "Company"):

(1) We have audited or reviewed the Company's reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.

(2) The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our audit and review.

(3) We carried out our audit and review 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).

(4) Those standards require that we plan and perform an audit and review to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An audit and review 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%, included in the reserves data of the Company audited and reviewed for the year ended December 31, 2019, and identifies the respective portions thereof that we have audited and reviewed and reported on to the Company's management and board of directors.

Independent Qualified Reserves Evaluator or Auditor	Effective Date	Location of Reserves (Country)	Net Present Value of Future Net Revenue (Before Income Taxes, 10% Discount Rate)			
			Audited (MM$)	Evaluated (MM$)	Reviewed (MM$)	Total (MM$)[2]
Sproule Associates Limited	December 31, 2019	Canada	15,796.4	Nil	(59.8)[1]	15,736.7
		China	4,334.8	Nil	—	4,334.8
		Indonesia	779.2	Nil	—	779.2
			20,910.4	**Nil**	**(59.8)[1]**	**20,850.6**

[1] Negative NPV10 results from inclusion of Canadian Abandonment and Reclamation costs for all existing assets
[2] Numbers may not add due to rounding

(6) In our opinion, the reserves data audited by us have, in all material respects, been determined and are in accordance with the COGE Handbook, consistently applied. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

(7) We have no responsibility to update our report 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.

Sproule Associates Limited
Calgary, Alberta
January 31, 2020

/s/ Art McMullen, P.Eng.
Art McMullen, P.Eng.
Senior Manager, Engineering and Regional Director, Asia Pacific

/s/ Alec Kovaltchouk, P.Geo.
Alec Kovaltchouk, P.Geo.
VP, Geoscience

/s/ Charles Wong
Charles Wong, P.Eng.
Petroleum Engineer

/s/ Cameron P. Six, P.Eng.
Cameron P. Six, P.Eng.
President and Chief Executive Officer

Husky Energy Inc.

Report of Management and Directors on Oil and Gas Disclosure

Management of Husky Energy Inc. (the "Company") 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.

An independent qualified reserves auditor has audited and reviewed the Company's reserves data. The report of the independent qualified reserves auditor will be filed with securities regulatory authorities concurrently with this report.

The Audit Committee of the board of directors of the Company has:

a. reviewed the Company's procedures for providing information to the independent qualified reserves auditor;

b. met with the independent qualified reserves auditor to determine whether any restrictions affected the ability of the independent qualified reserves auditor to report without reservation; and

c. reviewed the reserves data with management and the independent qualified reserves auditor.

The Audit Committee of the board of directors has reviewed the Company'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 of the independent qualified reserves auditor on the reserves data; and

c. the content and filing of this report.

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 26, 2020

Robert J. Peabody
President & Chief Executive Officer

/s/ Robert W. P. Symonds — February 26, 2020

Robert W. P. Symonds
Chief Operating Officer

/s/ William Shurniak — February 26, 2020

William Shurniak
Director

/s/ Stephen E. Bradley — February 26, 2020

Stephen E. Bradley
Director

Husky Energy Inc.

Independent Qualified Reserves Auditor Audit Opinion

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

Attention: Mr. Richard Leslie, Director, Reserves

Re: Audit of Husky Energy Inc.'s 2019 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, 2019. 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 (section 5.3.3 of the Third Edition). 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.

For the 2019 year-end audit Sproule also reviewed the internal Husky reserve evaluation for all of the intermediate and minor properties that were not audited. Thus, for the 2019 year-end Sproule has either audited or reviewed every Husky property that was assigned reserves.

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, 2019		
	Working Interest Before Royalty Company Share of Remaining Reserves (mmboe)	Company Share of Net Present Value Before Income Tax (MM$) @ 10%
Total Proved	1,431	12,292
Total Proved Plus Probable	2,105	20,851

Sincerely,

Sproule Associates Limited

/s/ Cameron P. Six, P. Eng.
Cameron P. Six, P. Eng.
President and Chief Executive Officer
Calgary, Alberta
January 31, 2020