ATHABASCA
OIL CORPORATION

Annual Information Form

FOR THE YEAR ENDED DECEMBER 31, 2019

March 4, 2020

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FORWARD-LOOKING STATEMENTS

This Annual Information Form contains forward-looking statements and information. The use of any of the words "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "predict", "pursue" and "potential" and similar expressions are intended to identify forward-looking statements. Since forward-looking statements address future events or conditions, they involve inherent risks and uncertainties. Actual results or events could differ materially from those anticipated in such statements. No assurance can be given that expectations will prove to be correct and forward-looking statements included in this Annual Information Form should not be unduly relied upon. These statements speak only as of the date of this Annual Information Form.

This Annual Information Form contains forward-looking statements that include, but are not limited to:

- the reserve and resource potential of Athabasca’s assets;
- our business strategy, objectives and opportunities;
- access to third-party infrastructure including pipeline and rail;
- our capital expenditure program and future capital requirements;
- our projections of commodity prices, costs and netbacks;
- anticipated future abandonment and reclamation costs;
- our expectations regarding raising capital;
- supply and demand fundamentals for oil, bitumen blend, natural gas and diluent;
- timing and size of Athabasca’s operations, development projects, optimizations and anticipated production levels;
- production and design capacity of Athabasca’s assets;
- our expectations of meeting our financing and other obligations;
- the estimated quantity and value of our reserves and contingent resources;
- our anticipated land expiries;
- drilling and completion plans;
- utilization of the Kaybob Carry Commitment;
- industry conditions;
- Athabasca’s treatment under regulatory and royalty regimes and tax laws; and
- the anticipated impact of the factors discussed under the heading “*Risk Factors*”.

The forward-looking statements are based on key expectations and assumptions that include, but are not limited to:

- general economic and financial market conditions;
- commodity prices, exchange rates and interest rates;
- future sources of funding for Athabasca’s capital programs and Athabasca’s ability to obtain financing on acceptable terms;
- the regulatory framework governing royalties, taxes, environmental protection and foreign investment;
- Athabasca’s ability to transport and market production;
- our future production levels;
- the success of our exploration and development activities;
- operating costs and capital expenditures;
- recoverability of Athabasca’s reserves and contingent resources;
- Athabasca’s future debt levels;
- compliance of counterparties in contractual arrangements with Athabasca;
- geological and engineering estimates in respect of Athabasca’s reserves and contingent resources; and
- the impact of competition on Athabasca.

Some of the risks that could affect our future results and cause results to differ materially from those expressed in the forward-looking statements include, but are not limited to:

- Weakness in the Oil and Gas Industry;

- Exploration, Development and Production Risks;
- Prices, Markets and Marketing;
- Market Conditions;
- Climate Change and Carbon Pricing Risk;
- Regulatory Environment and Changes in Applicable Law;
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- Competition;
- Chain of Title and Expiration of Licenses and Leases;
- Breaches of Confidentiality;
- New Industry Related Activities or New Geographical Areas; and
- Risks related to our Debt and Securities.

In each case as further described under the heading "*Risk Factors*".

Readers are cautioned that our list of risk factors should not be construed as exhaustive. In addition, statements relating to "reserves" and "resources" are deemed to be forward-looking information and statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated, and that the reserves and resources described can be profitably produced in the future.

Although management of the Company believes that the assumptions underlying and the expectations reflected in the forward-looking information are reasonable, significant risks and uncertainties are involved in such information. Management can give no assurances that its assumptions, estimates and expectations will prove to have been correct. Forward-looking information should not be read as guarantees of future performance or results and will not necessarily be accurate indications of whether such performance or results will be achieved. Many factors that are beyond Athabasca's control could cause actual results to differ materially from the results discussed in the forward-looking statements.

The forward-looking statements included in this Annual Information Form are expressly qualified by this cautionary statement and are made as of the date of this Annual Information Form. The Company does not undertake any obligation to publicly update or revise any forward-looking statements, except as required by applicable securities laws.

ABBREVIATIONS

In this Annual Information Form, the abbreviations set forth below have the following meanings:

bbl	barrel
bbl/d	barrels per day
BOE or boe	barrels of oil equivalent
Boe/d	barrels of oil equivalent per day
MMboe	million barrels of oil equivalent
Mbbl	thousand barrels
MMbbl	million barrels
Mcf	thousand cubic feet
Mcfe	thousand cubic feet equivalent
MMcf	million cubic feet
MMcf/d	million cubic feet per day
Bcf	billion cubic feet

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

CONVERSIONS AND CONVENTIONS

The following table sets forth certain standard conversions from Standard Imperial units to the International System of Units (or metric units).

To Convert From	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.315
Bbl	cubic metres	0.159
cubic metres	Bbl	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.500

OUR COMPANY

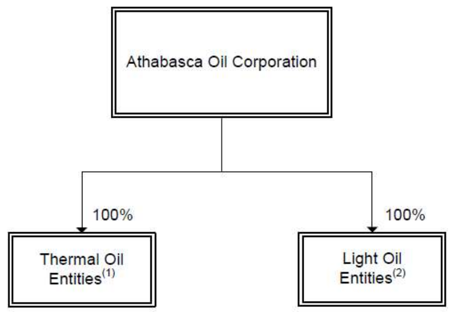
Name, Address and Incorporation

The Company was incorporated as "Athabasca Oil Sands Corp." under the ABCA on August 23, 2006 and we filed articles of amendment to remove our private company restrictions on September 1, 2006. On March 22, 2010, we filed articles of amendment to create first preferred shares, issuable in series, and second preferred shares, issuable in series. On May 10, 2012, we filed articles of amendment to change our name from "Athabasca Oil Sands Corp." to "Athabasca Oil Corporation".

Our head office is located at Suite 1200, 215 – 9th Avenue S.W., Calgary, Alberta T2P 1K3, and our registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta T2P 1G1.

Intercorporate Relationships

The following simplified organizational chart and related notes illustrate our intercorporate relationships and our material subsidiaries, as at December 31, 2019, including the percentage of votes attaching to the voting securities of the entities that are beneficially owned, controlled or directed (directly or indirectly) by us. Each of our subsidiaries is incorporated or formed under the laws of the Province of Alberta.



Notes:

(1) The "Thermal Oil Entities" are Alberta corporations and Alberta-formed partnerships that hold the Company's Thermal Oil assets and that are directly or indirectly wholly-owned by the Company: AOC Dover West Corp., AOC Grosmont Ltd., AOC Carbonates Ltd., AOC (ELE) Corp., AOC Birch Corp., AOC Dover West Partnership, AOC Grosmont Partnership, AOC Carbonates Partnership, AOC Hangingstone Partnership, AOC Birch Partnership, AOC Leismer Corner Partnership and 1686303 Alberta Ltd.

(2) The "Light Oil Entities" are Alberta corporations and Alberta-formed partnerships that hold the Company's Light Oil assets and that are directly or indirectly wholly-owned by the Company: AOC Light Oil Corp., AOC Kaybob Corp., AOC Simonette Corp., AOC Light Oil Partnership, AOC Kaybob Partnership and AOC Simonette Partnership.

Our Common Shares trade on the TSX under the trading symbol "ATH".

DEVELOPMENT OF OUR BUSINESS

Developments in 2019

During 2019, Western Canadian producers continued to face a challenging environment due to pipeline capacity constraints and dynamics in the global oil market which drove volatility in underlying commodity prices. The Alberta Government implemented mandatory industry production curtailments, commencing in January 2019, in an attempt to alleviate the high differential between Western Canadian Select Heavy ("WCS") and WTI pricing until additional pipeline egress is forthcoming. This action by the Alberta Government resulted in a significant improvement in Alberta inventory levels and a normalization in WCS heavy oil pricing in comparison to unprecedented levels reached in Q4 2018. The Alberta Government also announced a further initiative to provide curtailment relief by providing additional egress via crude-by-rail. The government crude by rail contracts were transferred to the private sector in early 2020. To address near-term market egress Athabasca has secured access to 130,000 bbl of leased storage capacity in Edmonton, Alberta and has also entered into 8,000 bbl/d of direct refinery sales through 2020 which mitigates apportionment risk on the Enbridge mainline. In the third quarter of 2019, the Company secured approximately 7,200 bbl/d of blended bitumen capacity on the TC Energy Keystone pipeline diversifying its end market access to the US Gulf Coast. Athabasca's long term market access initiatives include 25,000 bbl/d of capacity on the TC Energy Keystone XL pipeline and 20,000 bbl/d on the Trans Mountain Expansion Project which are expected to be in-service in late 2022. Based on the current market access constraints Athabasca's focus remains on sustaining corporate production through a minimal capital program aligned to corporate funds flow.

On January 15, 2019, we closed a transaction for the sale to Enbridge Pipelines of certain pipeline and storage infrastructure used to transport and store diluent and dilbit to and from our Leismer Project. For more details of this transaction see "*Development of our Business - Developments in 2018*".

Our Light Oil Division consists of two asset areas, Placid and Kaybob which we hold in a joint-venture with Murphy Oil Canada Ltd (See "*Description of Our Business-Light Oil Division*" and "*Glossary of Defined Terms*"). In the Placid area, we had previously drilled a multi-well Montney pad in the winter of 2018. An additional multi-well Montney pad was drilled in the fall of 2019, maintaining flexibility for completion and tie-in of all 10 wells, which is expected in the first half of 2020. In the Kaybob asset area, activity for 2019 was focused on delineating the volatile oil window at Kaybob East, Kaybob West and Two Creeks. The program included 18 drills, 14 completions and 10 tie-ins.

In our Thermal Oil Division, activity remains focused on maintaining base production, cost optimization projects and retaining flexibly for long term projects. At Leismer we completed a steam de-bottleneck project, expanded non-condensable gas co-injection on mature pads and commissioned the Pad 7 sustaining pad which included five well pairs. We have also implemented diluent optimization projects at both Leismer and Hangingstone aimed at reducing blending costs.

In 2019, we received two government grants to support funding of certain capital projects designed to reduce the emissions intensity of our assets and recognized $4.6 million related to these grants.

Developments in 2018

In 2018, Canadian producers were faced with unprecedented volatility in Canadian heavy oil differentials due to pipeline capacity constraints and refinery turnarounds in key consuming US regions, which impacted profitability and financial results. Given a particularly challenging differential pricing environment in Q4, Athabasca voluntarily curtailed approximately 8,000 bbl/d of dilbit production from its Thermal Oil assets in November and December. On December 2, 2018, the Government of Alberta followed suit and announced a provincial temporary curtailment of crude oil and bitumen production, which came into force on January 1, 2019.

Athabasca optimized netback performance in 2018 by mitigating pipeline apportionment through direct sales of dilbit to refineries and through access to leased storage in Edmonton, Alberta. Athabasca also increased its contracted capacity on the TransCanada Keystone XL Pipeline to 25,000 bbl/d. See *"Development of Our Business – Developments in 2017*."

In 2018, Athabasca had considerable activity in its Light Oil Division. In Greater Placid, Athabasca placed two multi-well Montney pads on production in March and October 2018. An additional multi-well Montney pad was spud in the summer and rig released in November 2018. In Greater Kaybob, 26 Duvernay wells were placed on production in the Murphy-operated area. Given the volatility in 2018, Athabasca and Murphy agreed to extend the Kaybob Carry Commitment, which now expires in 2020.

At our Leismer Project in our Thermal Oil Division, field activity in 2018 included the tie-in of four standing infill wells and the installation of a fifth steam generator that was previously held in inventory. The steam generator reduces downtime for planned maintenance and provides excess steam capacity for the start-up of future sustaining well pairs. In May, we also completed a scheduled facility turn-around. During the turn-around, we completed the Norlite diluent tie-in which is expected to lower fixed costs by ~$20 million annually, improving margins and further enhancing the Leismer Project's low cost operating structure. In November, Athabasca commenced operations on its next Leismer sustaining pad (Pad 7).

On December 10, 2018, Athabasca entered into an agreement with Enbridge Pipelines for the sale of pipelines and storage facilities which transport and store dilbit and diluent related to Athabasca's Leismer Project. Key elements of the transaction include: (i) $265 million cash consideration with an annual toll of ~$26 million; (ii) priority service on pipelines and tanks with excess volumes receiving a discounted toll; and (iii) enhanced credit terms with Enbridge across Athabasca's Thermal Oil Division. The sale closed on January 15, 2019.

During 2018, Athabasca took a number of steps to enhance liquidity to ensure financial resiliency. In the second quarter of 2018, Athabasca renewed its $120 million Amended Credit Facility. See "*Capital Structure – Revolving Senior Secured Credit Facility*". Early in the fourth quarter, the Company obtained the release of a $41.5 million letter of credit from the Trans Mountain Pipeline Expansion project and secured a $25 million unsecured letter of credit facility with a Canadian bank that is supported by a performance guarantee from Export Development Canada. See "*Capital Structure – LC Facilities*". In December we reduced our head office staff by approximately 25%.

Developments in 2017

In the first quarter of 2017, Athabasca completed a transformational acquisition of thermal oil assets from Statoil pursuant to an agreement reached in 2016. The assets included the producing Leismer Project, delineated Corner lease and regional pipeline and tank infrastructure. (This regional infrastructure was sold to Enbridge in 2019. See "*Development of Our Business – Developments in 2018*".) Consideration consisted of $431 million cash (after closing adjustments), 100 million common shares and at prices above US$65/bbl WTI (inflation adjusted), annual contingent value payments ending in 2020. The effective date of the acquisition was January 1, 2017.

On February 24, 2017, Athabasca granted a royalty to Burgess Energy Holdings L.L.C. ("**Burgess**") on the Leismer and Corner properties for $90 million of cash consideration (the "**Acquisition Royalty**"). The Acquisition Royalty is based on a linear scale (0 – 12%) with a WCS benchmark. The minimum 2% trigger is US$60/bbl WCS and the Acquisition Royalty is not expected to materially impact the economics of future expansion phases or development projects and there are no associated commitments for development.

On February 24, 2017, the Company completed a balance sheet refinancing transaction in which it issued senior secured second lien notes due February 24, 2022 (the "**2022 Notes**") in the amount of US$450 million. The 2022 Notes bear interest at a rate of 9.875% per year, payable semi-annually, and are not subject to maintenance or financial covenants. Athabasca used the net proceeds from the 2022 Notes to repurchase prior notes. See "*Capital Structure – 2022 Notes*". In conjunction with the 2022 Notes, the Company established a $120 million reserve-based Amended Credit Facility with seven major financial institutions. The Amended Credit Facility is subject to a semi-annual borrowing base review and is guaranteed on a senior secured first lien basis on substantially all of the Company's assets. See "*Capital Structure – Revolving Senior Secured Credit Facility*". The Company also amended and restated its LC Facility. See "*Capital Structure – LC Facilities*".

In March 2017, Athabasca contracted for firm service on the Trans Mountain Pipeline Expansion to deliver up to 20,000 bbl/d of the Company's blended bitumen from Edmonton, Alberta to Burnaby, B.C. In November 2017, Athabasca entered into a firm service transportation agreement for 9,000 bbl/d of diluent on the Norlite pipeline from Edmonton, Alberta for service to the Leismer Project, effective May 2018. And in December 2017, Athabasca entered into a dilbit transportation services agreement for 10,000 bbl/d on the TransCanada Keystone XL Pipeline for a 20-year term commencing when the pipeline goes into service, which is expected to be in 2021.

Significant Acquisitions

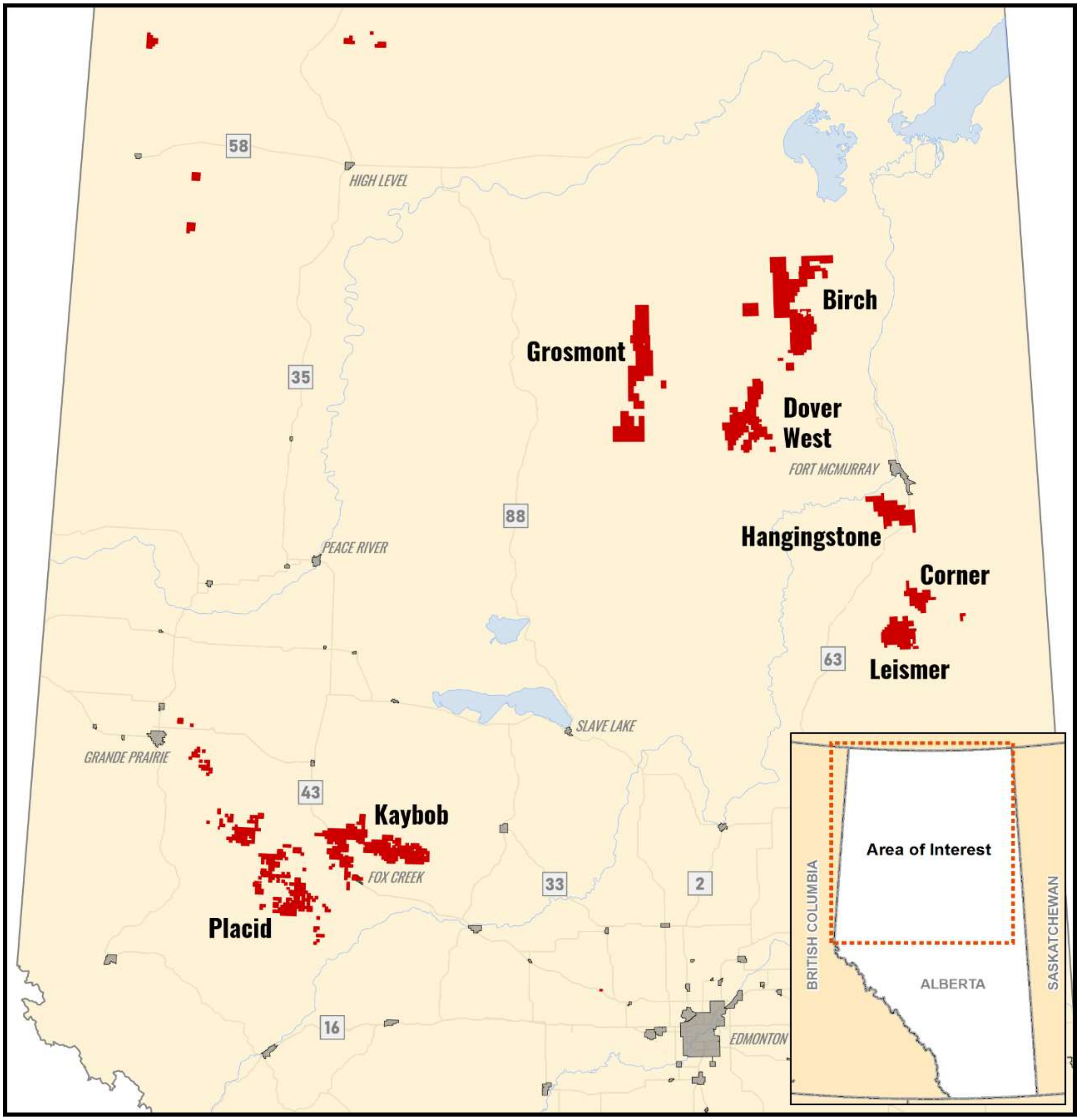
We have not completed any significant acquisitions during our most recently completed financial year for which disclosure is required under NI 51-102.

DESCRIPTION OF OUR BUSINESS

Our Development Strategy for Our Principal Properties

Athabasca is an intermediate liquids weighted producer with a position in three of Alberta's most active resource plays: the oil sands, Montney and Duvernay. We are organized into a Light Oil Division and a Thermal Oil Division. As at December 31, 2019, our principal properties in our Light Oil Division were in the Greater Placid area and in the Greater Kaybob area near the Town of Fox Creek in northwestern Alberta. Our Thermal Oil Division includes several major project areas in the Athabasca region of northeastern Alberta and, as at December 31, 2019, our producing properties included our Leismer and Hangingstone Projects.

The following map illustrates the locations of our principal assets as at December 31, 2019:



Athabasca's current business plan is to fund the development of our properties with cash flow from operations, the Kaybob Carry Commitment (which is expected to be fully utilized in Q1 of 2020), existing cash and cash-equivalents and available credit facilities. Any significant acceleration of our development activities or future expansion of our thermal oil projects will potentially require additional funding that could include debt, equity, joint ventures, asset sales or other external financing. The availability of any additional future funding will depend on, amongst other things, the commodity price environment, our operating performance, Athabasca's credit rating and the state of the equity and debt capital markets. See "*Risk Factors – Ability to Finance Capital Requirements*" for additional information.

Light Oil Division

Within its Light Oil Division, Athabasca produces light oil and liquids-rich natural gas from unconventional reservoirs. The Company's current focus in the Light Oil Division is targeting high margin and quick payout opportunities. The Company's principal development properties are located in the Greater Placid and Greater Kaybob areas. As discussed further below, Athabasca holds a 70% operated working interest in the Placid assets and a 30% non-operated interest in the Kaybob assets.

As of December 31, 2019, Athabasca held approximately 259,200 net acres of petroleum and natural gas rights in its Light Oil Division, which primarily includes rights in the Duvernay and Montney formations. Production from the Light Oil Division for the year ended December 31, 2019, averaged 10,138 boe/d (see "*Other Oil and Gas Information-Production History"* for production by product type).

Athabasca sells all of its oil and condensate produced from the Light Oil Division into the Pembina Pipeline system and receives Edmonton prices. Most of our natural gas is sent to Keyera Corp.'s Simonette Gas Plant where it is processed and sold into the TC Energy Pipeline and Alliance Pipeline systems. NGLs that are separated at this gas plant are transported through the Pembina Pipeline system and receive Edmonton prices. Athabasca's Kaybob assets are also connected to SemCAM's Kaybob amalgamated gas plant.

Placid Assets

Athabasca holds an operated 70% interest in the Placid assets, primarily targeting the development of the Montney formation. As of December 31, 2019, the Company held approximately 69,000 net acres in the Placid asset area.

McDaniel has assigned approximately 33 MMboe of Proved Reserves and 49 MMboe of Total Proved plus Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Placid asset area, as at December 31, 2019. See "*Statement of Reserves Data*".

During the year ended December 31, 2019, Athabasca spent approximately $30 million (net) in the Placid asset area on a program that consisted of: 4 (gross) wells drilled and initial preparations for completion operations on two multi-well pads (10 wells) scheduled to come on-stream in the first half of 2020.

Kaybob Assets

Athabasca holds a non-operated 30% interest in the Kaybob assets, primarily targeting the development of the Duvernay formation. Pursuant to the Kaybob Commitment Carry, Murphy agreed to fund 75% of the Company's 30% share of development capital up to a maximum of $219 million (approximately $1 billion gross). As at December 31, 2019, the remaining undiscounted capital-carry receivable was $22.7 million.

As of December 31, 2019, the Company held approximately 80,000 net acres in the Kaybob assets. McDaniel has assigned approximately 13 MMboe of Proved Reserves and 23 MMboe of Proved plus Probable Reserves on a Gross Reserves basis to Athabasca's interests in the Kaybob assets, as at December 31, 2019. See "*Statement of Reserves Data*".

The Company spent approximately $79 million ($21 million net of the capital-carry) on capital projects in the Kaybob assets during the year ended December 31, 2019. This capital program consisted of 18 (gross) wells drilled, 14 (gross) wells completed and 10 (gross) wells placed on production.

Thermal Oil Division

Athabasca's Thermal Oil Division consists of two operating oil sands SAGD projects and a large resource base of exploration areas in the Athabasca region of northeastern Alberta. The Thermal Oil Division provides Athabasca with a material low decline production base, capable of generating significant free cash flow for reinvestment across the business.

As of December 31, 2019, Athabasca's Thermal Oil Division held approximately 760,000 net acres of oil sands rights in the Athabasca region of northeastern Alberta. Sales from the Thermal Oil Division, for the year ended December 31, 2019, averaged 26,058 bbl/d of bitumen.

Activity remains focused on maintaining base production, cost optimization projects and retaining flexibility for long term projects.

Athabasca's Thermal Oil Division has marketing agreements on the Enbridge Waupisoo transportation pipeline which then accesses multiple sales points from Edmonton, Alberta. In the third quarter of 2019 we secured approximately 7,200 bbl/d of capacity on the existing TC Energy Keystone pipeline diversifying end market access to the US Gulf Coast. We have also secured 8,000 bbl/d of direct refinery sales for 2020 which mitigates apportionment risk on the

Enbridge Mainline. On a long-term basis, we have secured 20,000 bbl/d of blended bitumen capacity on the Trans Mountain Pipeline expansion and 25,000 bbl/d of blended bitumen capacity on the TC Energy Keystone XL Pipeline.

Leismer Corner Assets

On January 31, 2017, Athabasca acquired the Leismer assets, which include approximately 78,000 acres (net) of oil sands leases and a approximately 100% working interest in the operating Leismer Project. In the same transaction, we acquired approximately 44,000 net acres oil sands leases in the delineated Corner asset area. Collectively, we call these assets the Leismer Corner assets and they are located in northeastern Alberta ("**Leismer Corner Assets**").

McDaniel has assigned approximately 331 MMboe of Proved Reserves and 695 MMboe of Proved plus Probable Reserves on a Gross Reserves basis to the Leismer assets and 319 MMboe of risked (354 MMboe unrisked) Best Estimate Contingent Resources on a Company Interest basis to the Leismer assets as at December 31, 2019. See "*Appendix A – Supplemental Disclosure - Contingent Resource Estimates*".

The Leismer Project is a SAGD project that was commissioned in 2010 with December 2019 production of 20,075 bbl/d and regulatory approval to expand the capacity to 40,000 bbl/d. The Leismer Project averaged 17,565 bbl/d of bitumen production in 2019 with volumes impacted by mandated government curtailments early in the year and facility maintenance during the second quarter.

The Leismer Project has additional planned SAGD phases including a Leismer Project 2 phase with regulatory approvals and capacity to add 15,000 bbl/d and a further planned expansion phase, Leismer Project 3, with the ability to add another 40,000 bbl/d, which would take the Leismer assets to total planned capacity of approximately 80,000 bbl/d. For further details relating to Leismer expansions, please see "*Appendix "A" - Supplemental Disclosure - Contingent Resource Estimates*".

Future SAGD development for the delineated Corner assets includes two phases to take the assets up to 90,000 bbl/d of capacity. Development of the Corner assets is contingent upon various factors. For further detail relating to potential future development plans for the Corner assets please see "*Appendix A – Supplemental Disclosure - Contingent Resource Estimates*".

McDaniel has assigned approximately 353 MMboe of Proved plus Probable Reserves on a Gross Reserves basis to the Corner assets and 416 MMboe of risked (520 MMboe unrisked) Best Estimate Contingent Resources on a Company Interest basis to the Corner assets as at December 31, 2019. See "*Appendix A – Supplemental Disclosure - Contingent Resource Estimates*".

Hangingstone Assets

The Hangingstone assets are located approximately 20 kilometres southwest of the city of Fort McMurray in northeastern Alberta and include a concentrated, contiguous land base of approximately 86,000 net acres. Athabasca owns a 100% working interest. The reservoir suitable for in-situ recovery is the McMurray formation. The Hangingstone Project achieved first production in July 2015.

McDaniel has assigned approximately 80 MMboe of Proved Reserves and 177 MMboe of Proved plus Probable Reserves on a Gross Reserves basis to the Hangingstone assets as at December 31, 2019. See "*Statement of Reserves Data* ".

The Hangingstone Project has a facility capacity of 12,000 bbl/d and the Hangingstone assets have expansion capability of up to 80,000 bbl/d. The Hangingstone Project averaged 8,493 bbl/d and 9,024 bbl/d of bitumen production in 2019 and Q4 2019 respectively. Near-term activity is focused on cost optimization. Minimal development and maintenance capital will be required in the near-term to maintain a flat production profile.

Thermal Oil Exploration Areas

Athabasca's other thermal oil exploration areas are described below. Given current industry conditions, we have reduced activity in these areas and do not have immediate development plans or current capital allocated to them. For further details about these asset areas please see "*Appendix A – Supplemental Disclosure - Contingent Resource Estimates*".

Dover West Assets

McDaniel has assigned approximately 1,346 MMboe of risked (2,244 MMboe unrisked) Best Estimate Contingent Resources to the Dover West assets as at December 31, 2019. Athabasca has a 100% working interest in its Dover West assets which are located 90 kilometers north of Fort McMurray. The Dover West assets are geologically unique in that they contain three primary bitumen reservoirs. The bitumen reservoirs booked in the contingent resource includes the McMurray Formation and the Wabiskaw member of the Clearwater Formation (the Dover West Sands); Athabasca see further resource potential in the Leduc and Cooking Lake formations of the Devonian Woodbend Group (the Dover West Carbonates) which are not booked. As of December 31, 2019, the Dover West assets were comprised of a large contiguous land base of approximately 155,000 net acres.

Birch Assets

The Company holds a 100% working interest in the Birch assets. The Birch assets are located within the Athabasca oil sands fairway of northeastern Alberta, approximately 95 kilometres northwest of the city of Fort McMurray and are comprised of an extensive contiguous land base of approximately 286,000 net acres.

Grosmont Assets

Athabasca holds a 50% operated working interest in the Grosmont assets, which are located within the Athabasca oil sands fairway of northeastern Alberta. The Grosmont assets include approximately 110,000 net acres and are prospective for development in carbonate reservoirs.

Competition

Our industry is competitive in all its phases. We compete with numerous other participants in the acquisition, exploration and development of our assets and in the marketing of oil and natural gas. Our competitors include resource companies that may have greater financial resources, staff and facilities than us. We believe that our competitive position is, on the whole, equivalent to that of other producers of similar size and at a similar stage of development.

Environmental, Health and Safety Policies

We are committed to environmental protection and health and safety by integrating the essential principles and practices through our management systems and occupational health and safety programs. We strive to conduct our activities in a way that safeguards our employees, contractors, the environment and the public. Preserving air quality, biodiversity and water quality are considerations we address in all phases of our projects including planning, construction, operations and reclamation. We work with regulators, industry peers, multi-stakeholder organizations and communities to share information and continuously improve our environmental performance.

We develop emergency response teams and preparedness plans in conjunction with local authorities, emergency services and the communities in which we operate in order to effectively respond to an environmental, health or safety incident should it arise. We conduct audits of operations to confirm compliance with internal standards and to identify opportunities to improve our practices where needed. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist in achieving the objectives of our policies and programs.

To learn more about our health, safety & environment policies, please see our website at https://www.atha.com/responsibility.html.

Seasonal Factors

The exploration for and development of reserves is dependent on access to areas where operations are to be conducted. Seasonal weather variations, including freeze-up and break-up as well as forest fires affect access in certain circumstances. Unexpected adverse weather conditions can have negative impact on operations and costs.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected during the remainder of 2020 by the renegotiation or termination of contracts.

Personnel

As at December 31, 2019, Athabasca had 173 employees (comprised of 82 head office and 91 field employees).

STATEMENT OF RESERVES DATA

Independent Report

Athabasca is required to report its reserves and to provide other oil and gas information in accordance with NI 51-101—*Standards of Disclosure for Oil and Gas Activities*. We engaged McDaniel to independently assess and evaluate Athabasca's bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves as at December 31, 2019. McDaniel carried out its evaluation in accordance with standards established in NI 51-101. Those standards require that the bitumen, light crude oil and medium crude oil, shale oil, conventional natural gas, shale gas and NGL reserves be prepared in accordance with the COGE Handbook. The reserves estimates set out below reflect the Company's working interests (as at December 31, 2019) in the Leismer, Hangingstone and Corner assets and its interests in the Light Oil assets.

The effective date of the information provided below is December 31, 2019 and the preparation date of the McDaniel Report is March 3, 2020. The Independent Evaluator's responsibility is to express opinions on the bitumen, light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves including the associated estimated net present values. The preparation and disclosure of the reported reserves estimates is the responsibility of Athabasca's management.

McDaniel's Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor is set forth in Appendix "C" to this Annual Information Form. Athabasca's Report of Management and Directors on Oil and Gas Disclosure in the form of NI 51-101F3 is set forth in Appendix "B" to this Annual Information Form. The reserves estimates presented in the Independent Report are based upon the definitions and guidelines contained in the COGE Handbook. A summary of those definitions is set forth below.

Information relating to Athabasca's reserves constitutes forward-looking information, which is subject to certain risks and uncertainties. See "*Forward-Looking Statements*" for additional information.

Reserves Classifications

Reserves Categories

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on:

- analysis of drilling, geological, geophysical, and engineering data;
- the use of established technology; and
- specified economic conditions, which are generally accepted as being reasonable and shall be disclosed.

Reserves are classified according to the degree of certainty associated with the estimates:

- "**Proved Reserves**" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves.

- "**Probable Reserves**" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved Reserves plus Probable Reserves.

Development and Production Status

Each of the Proved and Probable Reserves categories may be further divided into "developed" and "undeveloped" categories:

- "**developed reserves**" are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing:
    - "**developed producing reserves**" are those reserves that are expected to be recovered from wells at the time of the estimate. These reserves may be currently producing or, if shut in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.
    - "**developed non-producing reserves**" are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
- "**undeveloped reserves**" are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (Proved Reserves or Probable Reserves) to which they are assigned.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to "individual reserves entities" (which refers to the lowest level at which reserves calculations are performed) and to "reported reserves" (which refers to the highest-level sum of individual entity estimates for which reserves estimates are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves; and
- at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved Reserves plus Probable Reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates are prepared using deterministic methods that do not provide a mathematically derived quantitative measure or probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods. Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

Reserves Estimates

Set out below is a summary of Athabasca's reserves, as well as the estimated value of future net revenue of Athabasca from the reserves, as at December 31, 2019, evaluated in the McDaniel Report. The pricing used in the forecast price evaluations for all assets is set forth below under "*McDaniel Price Forecast*".

As at December 31, 2019, Athabasca's bitumen reserves were contained in its Leismer, Hangingstone and Corner assets. Proved Reserves were assigned by McDaniel to the Hangingstone and Leismer Projects, and Probable Reserves were assigned by McDaniel to the Hangingstone and Leismer Projects as well as expansion phases that include Leismer Project 2 and the Corner Projects. Athabasca's light crude oil and medium crude oil, tight oil, conventional natural gas, shale gas and NGL reserves are all associated with Athabasca's Light Oil assets. Both Proved Reserves and Probable Reserves have been assigned by McDaniel to Athabasca's Light Oil assets.

All evaluations of future net revenue are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in the following tables do not represent the fair market value of Athabasca's reserves. There is no assurance that the forecast price assumptions that have been estimated by McDaniel will be realized and variances could be material. Other assumptions have been made by McDaniel and qualifications relating to costs and other matters are included in the McDaniel Report. The recovery and reserves estimates of Athabasca's properties described herein are estimates only. The actual reserves of Athabasca's properties may be greater or less than those calculated.

Summary of Reserves Data – Forecast Prices and Costs as of December 31, 2019[(1)(2)(8)]

Reserve Category	Bitumen Gross (Mbbl)	Bitumen Net (Mbbl)	Tight Oil & Light/Medium Crude Oil Gross (Mbbl)	Tight Oil & Light/Medium Crude Oil Net (Mbbl)	Conventional Natural Gas Gross (MMcf)	Conventional Natural Gas Net (MMcf)
PROVED RESERVES						
Developed Producing	68,160	64,393	2,971	2,628	809	768
Developed Non-Producing	0	0	0	0	0	0
Undeveloped	342,053	267,182	4,751	4,088	0	0
TOTAL PROVED RESERVES	410,212	331,575	7,722	6,716	809	768
TOTAL PROBABLE RESERVES	814,745	593,404	7,201	5,748	83	78
TOTAL PROVED PLUS PROBABLE RESERVES	1,224,958	924,979	14,923	12,464	892	847

Reserve Category	Shale Gas Gross (MMcf)	Shale Gas Net (MMcf)	Natural Gas Liquids Gross (Mbbl)	Natural Gas Liquids Net (Mbbl)	Oil Equivalent Gross (Mboe)	Oil Equivalent Net (Mboe)
PROVED RESERVES						
Developed Producing	38,495	36,531	3,224	2,653	80,905	75,891
Developed Non-Producing	2,826	2,683	402	362	873	809
Undeveloped	92,607	87,434	11,779	10,209	374,017	296,051
TOTAL PROVED RESERVES	133,927	126,648	15,404	13,223	455,795	372,751
TOTAL PROBABLE RESERVES	70,599	65,933	7,919	6,218	841,646	616,372
TOTAL PROVED PLUS PROBABLE RESERVES	204,527	192,581	23,324	19,442	1,297,441	989,123

For notes please see the notes following the "*Reconciliation of Reserves by Principal Product Type*" table

Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2019[(1)(2)(3)(4)]

Reserve Category	Before Income Tax Discounted at (%/year)					After Income Tax Discounted at (%/year)					Net Unit Value Before Income Tax at 10% Discount/Year	
	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	0% (MM$)	5% (MM$)	10% (MM$)	15% (MM$)	20% (MM$)	$/boe	$/Mcfe
PROVED RESERVES												
Developed Producing	$1,346	$1,265	$1,115	$988	$886	$1,346	$1,265	$1,115	$988	$886	$14.70	$2.45
Developed Non-Producing	$20	$17	$15	$14	$13	$20	$17	$15	$14	$13	$19.17	$3.19
Undeveloped	$7,024	$3,208	$1,730	$1,048	$682	$5,720	$2,678	$1,481	$917	$607	$5.85	$0.97
TOTAL PROVED RESERVES	$8,390	$4,491	$2,861	$2,050	$1,581	$7,086	$3,961	$2,612	$1,919	$1,506	$7.68	$1.28
TOTAL PROBABLE RESERVES	$18,241	$5,380	$2,095	$943	$447	$13,948	$4,023	$1,515	$643	$273	$3.40	$0.57
TOTAL PROVED PLUS PROBABLE RESERVES	$26,630	$9,871	$4,956	$2,993	$2,027	$21,034	$7,985	$4,127	$2,562	$1,779	$5.01	$0.84

For notes please see the notes following the "*Reconciliation of Reserves by Principal Product Type*" table

Future Net Revenue (Undiscounted) – Forecast Prices and Cost as of December 31, 2019[(1)(2)(3)(4)]

Reserve Category	Revenue ($MM)	Royalties ($MM)	Operating Costs ($MM)	Development Costs ($MM)	Abandonment and Reclamation Costs ($MM)	Future Net Revenue Before Future Income Tax Expense ($MM)	Future Income Tax Expense ($MM)	Future Net Revenue After Future Income Tax Expense ($MM)
PROVED RESERVES	$27,194	$5,551	$7,873	$4,772	$607	$8,390	$1,304	$7,086
PROBABLE RESERVES	$66,180	$18,510	$15,734	$13,224	$472	$18,241	$4,293	$13,948
PROVED PLUS PROBABLE	$93,374	$24,061	$23,608	$17,996	$1,079	$26,630	$5,597	$21,034

For notes please see the notes following the "*Reconciliation of Reserves by Principal Product Type*" table

Future Net Revenue by Product Type – Forecast Prices and Costs as of December 31, 2019(1)(2)(3)(5)(6)

Reserve Category	Production Group	Future Net Revenue Before Income Taxes (Discounted at 10%/Yr and net vol.)		
	($M)	$MM	$/bbl	$/Mcfe
PROVED RESERVES	Bitumen	$2,486	$7.50	$1.25
	Tight Oil	$165	$25.24	$4.21
	Conventional Natural Gas	$1	$6.99	$1.16
	Shale Gas	$209	$11.89	$1.98
	TOTAL	**$2,861**	**$7.68**	**$1.28**
PROVED PLUS PROBABLE	Bitumen	$4,352	$4.70	$0.78
	Tight Oil	$250	$20.38	$3.40
	Conventional Natural Gas	$1	$7.10	$1.18
	Shale Gas	$354	$13.60	$2.27
	TOTAL	**$4,956**	**$5.01**	**$0.84**

For notes please see the notes following the "*Reconciliation of Reserves by Principal Product Type*" table

Reconciliation of Reserves by Principal Product Type – Forecast Prices and Costs as of December 31, 2019)(1)(2)(3)(5)(7)(8)(9)

The following table sets forth a reconciliation of the changes of Athabasca's reserves estimates, before royalties, of bitumen, tight oil, light/medium crude oil, conventional natural gas, shale gas and NGL as at December 31, 2019, compared to such reserves as at December 31, 2018, based on the forecast price and cost assumptions that are described in Note 1 below.

	Bitumen			Tight Oil & Light/Medium Crude Oil		
Factors	**Gross Proved Reserves (MMbbl)**	**Gross Probable Reserves (MMbbl)**	**Gross Proved + Probable Reserves (MMbbl)**	**Gross Proved Reserves (MMbbl)**	**Gross Probable Reserves (MMbbl)**	**Gross Proved + Probable Reserves (MMbbl)**
December 31, 2018	403.8	800.9	1,204.7	7.7	5.9	13.6
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	0.0	5.5	5.5	0.5	0.7	1.2
Technical Revisions	15.8	8.4	24.2	0.5	0.5	1.0
Acquisition	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	0.0	0.0	0.0
Production	-9.4	0.0	-9.4	-0.9	0.0	-0.9
December 31, 2019	**410.2**	**814.7**	**1,225.0**	**7.7**	**7.2**	**14.9**

	Conventional Natural Gas			Shale Gas		
Factors	**Gross Proved Reserves (Bcf)**	**Gross Probable Reserves (Bcf)**	**Gross Proved + Probable Reserves (Bcf)**	**Gross Proved Reserves (Bcf)**	**Gross Probable Reserves (Bcf)**	**Gross Proved + Probable Reserves (Bcf)**
December 31, 2018	2.2	0.4	2.6	144.9	68.7	213.6
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	0.0	0.0	0.0	0.6	18.4	18.9
Technical Revisions	-1.2	-0.3	-1.5	-0.5	-16.4	-17.0
Acquisition	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	0.0	0.0	0.0	-0.8	0.0	-0.8
Production	-0.1	0.0	-0.1	-10.2	0.0	-10.2
December 31, 2019	**0.8**	**0.1**	**0.9**	**133.9**	**70.6**	**204.5**

	Natural Gas Liquids			Oil Equivalent		
Factors	**Gross Proved Reserves (MMbbl)**	**Gross Probable Reserves (MMbbl)**	**Gross Proved + Probable Reserves (MMbbl)**	**Gross Proved Reserves (MMbbl)**	**Gross Probable Reserves (MMbbl)**	**Gross Proved + Probable Reserves (MMbbl)**
December 31, 2018	17.2	7.3	24.5	453.1	825.7	1,278.9
Discoveries	0.0	0.0	0.0	0.0	0.0	0.0
Extensions and Improved Recovery	0.0	2.3	2.3	0.6	6.1	12.2
Technical Revisions	-0.7	-1.7	-2.4	15.3	9.8	19.7
Acquisition	0.0	0.0	0.0	0.0	0.0	0.0
Dispositions	0.0	0.0	0.0	0.0	0.0	0.0
Economic Factors	-0.1	0.0	-0.1	-0.2	0.0	-0.3
Production	-1.0	0.0	-1.0	-13.0	0.0	-13.0
December 31, 2019	**15.4**	**7.9**	**23.3**	**455.8**	**841.6**	**1,297.4**

Notes:

(1) Based on the Independent Report. Future net revenue estimates were calculated by McDaniel using the pricing assumptions set forth below under "*McDaniel Price Forecast*" to ensure for consistency and in accordance with the COGE Handbook.

(2) Totals may not add due to rounding.

(3) All evaluations of future net revenue are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. For further detail on what is and isn't included in abandonment and reclamation costs, please see the "*Abandonment and Reclamation Obligations for Properties with Reserves*".

(4) The estimated tax burden included in the after-tax net present values of the Company's oil and gas properties is reflected at the corporate consolidation level and does not consider tax planning or provide an estimate of the tax burden at the business entity level which may be significantly different.

(5) Including by-products but excluding solution gas.

(6) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups. Unit values are based on Company Net Reserves.

(7) Infill drilling is included in the Extensions and Improved Recovery Category.

(8) Light/Medium Crude Oil has been combined with Tight Oil for reporting purposes. Tight Oil accounts for greater than 99% of the reported volumes in this category as of December 31st, 2019.

(9) Positive technical revisions for bitumen reserves were driven by the technical interpretation of Leismer Pad 7 observations wells (OBIP mapping) and the Leismer Pad 7 SAGD wells (5) coupled with field wide improvements in recovery factors. Negative technical revisions for shale gas were primarily driven by a revised field development design in the Placid Montney play. Average horizontal well lengths were decreased from 2,600 m to 2,400 m resulting in lower per well type curve recoveries.

McDaniel Price Forecast

The price forecast that formed the basis for McDaniel's revenue projections and net present value estimates is based on a price deck that averages the McDaniel, GLJ and Sproule January 1, 2020 price forecasts. A summary of the forecast is set forth below.

Year	Inflation	Exchange Rate	WTI Crude Oil	Edmonton Light Crude Oil	Western Canadian Select Crude Oil	US Henry Hub Gas	AECO Spot Gas	Pentanes Edmonton	Butane Edmonton	Propane Edmonton
	%	US$/C$	US$/bbl	C$/bbl	C$/bbl	US$/MMBtu	C$/MMBtu	C$/bbl	C$/bbl	C$/bbl
2020	0	0.76	$61.00	$72.64	$57.57	$2.62	$2.04	$76.83	$42.10	$26.36
2021	1.7	0.77	$63.75	$76.06	$62.35	$2.87	$2.32	$79.82	$47.03	$29.80
2022	2	0.79	$66.18	$78.35	$64.33	$3.06	$2.62	$82.30	$50.66	$32.94
2023	2	0.79	$67.91	$80.71	$66.23	$3.17	$2.71	$84.72	$52.21	$34.00
2024	2	0.79	$69.48	$82.64	$67.97	$3.24	$2.81	$86.71	$53.48	$34.88
2025	2	0.79	$71.07	$84.60	$69.72	$3.32	$2.89	$88.73	$54.77	$35.78
2026	2	0.79	$72.68	$86.57	$71.49	$3.39	$2.96	$90.77	$56.07	$36.69
2027	2	0.79	$74.24	$88.49	$73.20	$3.45	$3.03	$92.76	$57.32	$37.57
2028	2	0.79	$75.73	$90.31	$74.80	$3.53	$3.09	$94.65	$58.50	$38.41
2029	2	0.79	$77.24	$92.17	$76.43	$3.60	$3.16	$96.57	$59.71	$39.26
2030	2	0.79	$78.79	$94.01	$77.96	$3.67	$3.23	$98.50	$60.90	$40.04
2031	2	0.79	$80.36	$95.89	$79.52	$3.74	$3.29	$100.47	$62.12	$40.85
2032	2	0.79	$81.97	$97.81	$81.11	$3.82	$3.36	$102.48	$63.36	$41.66
2033	2	0.79	$83.61	$99.76	$82.73	$3.89	$3.43	$104.53	$64.63	$42.50
2034	2	0.79	$85.28	$101.76	$84.39	$3.97	$3.49	$106.62	$65.92	$43.35
Thereafte	2	flat	~2%/year	~2%/year	~2%/year	~2%/year	~2%/year	~2%/year	~2%/year	~2%/year

The weighted average realized sales prices for Athabasca for the year ended December 31, 2019 were $45.29/bbl for bitumen, $67.21/bbl for tight oil, $1.67/Mcf for conventional natural gas, $30.28/bbl for NGL, and $2.55/Mcf for shale gas.

Undeveloped Reserves

The proved undeveloped bitumen reserves attributed to the Leismer Project and the Hangingstone Project will transition to proved developed reserves with the drilling and start-up of sustaining wells. The probable undeveloped bitumen reserves attributed to the Hangingstone Project will transition to proved developed reserves with the drilling and start-up of additional sustaining wells. The probable undeveloped bitumen reserves attributed to Leismer Project 2 and the Corner Project will transition to proved developed reserves with the sanctioning, construction and commissioning of the Leismer Project 2 and the Corner Project, respectively.

Once proved and/or probable undeveloped reserves are identified in respect of Athabasca's Light Oil assets, they are generally scheduled into Athabasca's development plans. Athabasca plans to develop the proved and probable undeveloped reserves that have been attributed to its light oil assets within the next nine years. Development plans have been designed to be funded within cash flow in the current commodity price environment. Athabasca's undeveloped bitumen reserves, which are considered to be longer term opportunities, are expected to be developed over the next several decades. For additional information regarding projects that have undeveloped bitumen reserves, see "*Description of Our Business – Our Development Strategy for Our Principal Properties - Thermal Oil Division*".

A number of factors that could result in delayed or cancelled development plans are as follows:

- changing economic conditions (e.g. due to pricing, operating and capital expenditure fluctuations);
- transportation and marketing issues (e.g. availability of diluent, access to market for production due to pipeline delays or unavailability of rail transportation);
- changing technical conditions (e.g. production anomalies, such as water breakthrough or accelerated depletion);
- multi-zone developments (e.g. prospective formation completion may be delayed until the initial completion is no longer economic);
- availability and allocation of capital based on other opportunities available to Athabasca in any given year;
- a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization;
- surface access issues (e.g. landowner issues, weather conditions and receipt of required regulatory approvals); and
- changes in the legal & regulatory framework applicable to the assets (e.g., rendering it uneconomic, difficult or impossible to proceed with development).

The following table set out the volumes of proved undeveloped reserves and probable undeveloped reserves that were attributed for each of Athabasca's product types for each of Athabasca's most recent three financial years using forecast prices and costs:

Proved Undeveloped Reserves(1)(2(3)

	Bitumen (MMbbl)		Conventional Natural Gas (Bcf)		Natural Gas Liquids (MMbbl)	
Year	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**
2017	286.6	330.6	0.0	0.0	14.6	16.5
2018	0.0	341.3	0.0	0.0	0.7	12.7
2019	0.0	342.1	0.0	0.0	0.0	11.8

	Tight Oil & Light/Medium Crude Oil (MMbbl)		Shale Gas (Bcf)		Oil Equivalent (MMbbl)	
Year	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**
2017	5.4	4.8	133.4	138.9	328.8	375.0
2018	0.0	4.5	4.9	98.5	1.5	374.9
2019	0.0	4.8	0.0	92.6	0.0	374.0

Probable Undeveloped Reserves(1)(2)(3)

	Bitumen (MMbbl)		Conventional Natural Gas (Bcf)		Natural Gas Liquids (MMbbl)	
Year	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**
2017	683.9	763.9	0.0	0.0	3.0	7.0
2018	0.0	792.2	0.0	0.0	2.8	6.4
2019	5.5	804.5	0.0	0.0	2.3	7.3

	Tight Oil & Light/Medium Crude Oil (MMbbl)		Shale Gas (Bcf)		Oil Equivalent (MMbbl)	
Year	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**	**First Attributed**	**Total at Year-End**
2017	4.3	4.1	36.6	58.6	697.4	784.8
2018	1.3	5.0	22.7	58.6	7.9	813.4
2019	0.6	6.4	18.2	62.2	11.4	828.6

Notes:

(1) "First Attributed" refers to the initial allocation of an undeveloped volume of reserves by the Company for the corresponding financial year.

(2) Based on the Independent Report.

(3) Light/Medium Crude Oil has been combined with Tight Oil for reporting purposes. Tight Oil accounts for greater than 99% of the reported volumes in this category as of December 31st, 2019.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions and other factors and assumptions that may affect the reserves estimates and the present worth of the future net revenue therefrom. See "*Risk Factors – Reserves*".

As circumstances change and additional data becomes available, reserve estimates may also change. Estimates made are reviewed and revised, either upward or downward, as warranted by new information. Revisions may be required as a result of a number of factors that are beyond Athabasca's control, including, among others, product pricing, economic conditions, access to markets, changes to royalty and tax regimes, governmental restrictions, changing operating and capital costs, surface access issues, the receipt of regulatory approvals, availability of services and processing facilities and technical issues affecting well performance. Although every reasonable effort is made to ensure that reserves estimates are accurate, reserve estimation is an inferential science and revisions to reserve estimates based upon the foregoing factors may be either positive or negative.

Abandonment and Reclamation Obligations for Properties with Reserves

In connection with Athabasca's operations, Athabasca will incur abandonment and reclamation costs for surface leases, wells and associated pads with proved and probable reserves, interconnecting flowlines, trunk lines, central processing facilities and all related infrastructure facilities and pipelines. Athabasca budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its property, plant and equipment. Athabasca's overall abandonment and reclamation costs include all costs associated with the process of restoring a property that has been disturbed by oil and gas activities to the standard imposed by the applicable government or regulatory authorities. These costs were estimated using amongst other things, Athabasca's experience conducting abandonment and reclamation programs, previous actual costs incurred and published industry information. Athabasca reviews suspended or standing wells for reactivation, recompletion or sale and conducts systematic abandonment programs for those wells that do not meet its criteria. A portion of Athabasca's liability issues are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of Athabasca's liability reduction programs take into account seasonal access, high priority and stakeholder issues, requirements of applicable laws and opportunities for multi-location programs to reduce costs. There are no unusually significant abandonment and reclamation costs associated with our properties with attributed reserves. See "*Other Oil and Gas Information – Properties With No Attributed Reserves*" for a discussion of certain abandonment and reclamation liabilities associated with properties with no attributed reserves.

The future net revenues disclosed in this Annual Information Form are based on the McDaniel Report and contain an allowance for abandonment and reclamation costs for wells and facilities with reserves associated with the Light Oil, Leismer, Hangingstone and Corner assets; however, such amount did not include an allowance for Athabasca's inactive assets that are geographically disconnected from the active properties where reserves have been assigned. The future net revenue disclosures contained in the Independent Report also includes reclamation and abandonment costs associated with future development wells and facilities which were not included in the Company's consolidated financial statements. The McDaniel Report deducted an aggregate of $1.1 billion (undiscounted) and $87 million (10% discount) for abandonment and reclamation costs of wells and facilities with proved and probable reserves.

As at December 31, 2019, the Company maintained a Liability Management Rating ("**LMR**") from the AER of 15.39 compared to the industry average of 4.87. A high rating indicates a low abandonment and reclamation burden relative to a company's assets. A company's LMR is determined by dividing that company's total deemed assets by its total deemed liabilities specified by AER Directives 006, 024 and 075.

***Future Development Costs*[1]**

The following table sets forth the undiscounted development costs deducted in the estimation of future net revenue attributable to each of the following reserves categories contained in the Independent Report.

Year	Total Proved Reserves Future Development Costs (MM$)	Total Proved Plus Probable Reserves Future Development Costs (MM$)
2020	$289	$183
2021	$125	$226
2022	$190	$340
2023	$231	$574
2024	$182	$738
Total for all remaining years	**$3,755**	**$15,934**
Total Undiscounted	**$4,772**	**$17,996**

Note:
(1) Totals may not add due to rounding.

In 2020, it is anticipated that Athabasca's capital and operating activities, based on current business plans will be funded through cash flow from operating activities, the remainder of the Kaybob Carry Commitment, existing cash and cash equivalents and available credit facilities. Beyond 2020, depending on our level of capital spend and the commodity price environment, Athabasca may require additional funding which could include debt, equity, joint ventures, asset sales or other external financing. The availability of any additional future funding will depend on, among other things, the current commodity price environment, operating performance, the Company's credit rating at the time and the current state of the equity and debt capital markets. See "*Risk Factors – Ability to Finance Capital Requirements*" for additional information.

OTHER OIL AND GAS INFORMATION

Oil & Gas Properties

As at December 31, 2019, Athabasca held approximately 1,116,228 net acres of mineral resource leases, licenses and permits, including over 760,000 net acres of oil sands leases and permits in the Athabasca region of northeastern Alberta and 259,200 net acres of petroleum and natural gas leases in northwestern Alberta.

Oil sands leases in the Athabasca oil sands area carry a primary term of 15 years and petroleum and natural gas leases carry a primary term of 5 years, after which time the leases can be continued if certain evaluation activity and/or production levels are satisfied. Oil sands permits have a primary term of 5 years and petroleum and natural gas licenses have a primary term of 4 years in northern Alberta. Depending on the level of activity and/or production, both oil sands permits and petroleum and natural gas licenses can be converted into leases at the end of their terms. A vast majority of Athabasca's oil sands reserves and resources are held under oil sands leases and those lands held under oil sands permits have met all requirements to convert to leases at the end of their initial terms.

See "*Description of Our Business – Thermal Oil Division*" and "*Description of Our Business – Light Oil Division*". Athabasca's oil sands leases and permits are large and generally contiguous, which management expects will allow for scale efficiency and simpler development planning.

As at December 31, 2019, Athabasca had an interest in approximately 270 Gross Wells (166 Net Wells), as set forth below, all of which are located in Alberta:

	Producing		**Non-Producing**[3]		**Total**	
	Gross Wells[1]	**Net Wells**[2]	**Gross Wells**[1]	**Net Wells**[2]	**Gross Wells**[1]	**Net Wells**[2]
Bitumen	76	76	0	0	76	76
Crude Oil Wells	20	5.9	35	11.3	55	17.2
Natural Gas Wells	101	47.2	38	25.8	139	73
TOTAL	197	129.1	73	37.1	270	166.2

Notes:

(1) **Gross Wells**" means the total number of producing or non-producing bitumen, oil or gas wells in which Athabasca had an interest as of December 31, 2019.

(2) "**Net Wells**" means the aggregate number of producing or non-producing bitumen, oil or gas wells obtained by multiplying each Gross Well by Athabasca's percentage working interest therein.

(3) "**Non-Producing**" wells include stratigraphic test wells, wells awaiting completion as at December 31, 2019, and wells that are capable of production but were not producing as at December 31, 2019, due to facility limitations or were waiting to be tied-in. All non-producing wells considered to be capable of producing are located near existing transportation infrastructure. Athabasca has not included the following type of wells in its Non-Producing well count above: wells in the Liege area that are suspended or permanently shut-in either due to a lack of existing functional proximate transportation infrastructure or a permanent shut-in order issued by the AER, its heater assembly facility, water source, steam injection, disposal wells or wells that have been abandoned.

Properties With No Attributed Reserves(1)(2)

The following table is a summary of properties in which Athabasca has an interest to which no reserves have been attributed, and also the number of net acres for which Athabasca's rights to explore, develop or exploit may, absent further action, expire within one year, as at December 31, 2019:

	Gross Acres(1)(2)	Net Acres(1)(2)	Net Acres Expiring Within One Year(1)(2)
Alberta	1,208,517	1,018,306	46,120
Total	1,208,517	1,018,306	46,120

Notes:

(1) "**Gross**" means the total area of properties in which Athabasca has a working interest. "**Net**" means the total area in which Athabasca has an interest multiplied by the working interest owned by Athabasca.

(2) Excludes certain non-oil sands acreage held by Athabasca in formations under and adjacent to the same surface area as Athabasca's oil sands leases. Athabasca measures its land acreage based on the leases, licenses and permits granted by the Crown, as specified within the applicable legal documentation.

Significant Factors and Uncertainties Relevant to Properties with No Attributed Reserves

We continually review the economic viability of our undeveloped properties using industry-standard economic evaluation techniques and pricing and economic assumptions. Each year as part of this process, some properties may be selected for further development activities while others may be held in abeyance, sold or relinquished back to the mineral rights owner. There is no guarantee that commercial reserves will be discovered or developed on these properties.

Liege Area Abandonment and Reclamation Obligations

In November 2010, Athabasca acquired 259 shut-in gas wells from Perpetual Energy Inc. in the Liege area, which were located in proximity to its oil sands assets including oil sands assets that were part of the Dover assets. These wells were the subject of a permanent gas over bitumen shut-in order issued by the ERCB (now AER) pursuant to shut-in orders *ERCB 2011-035* and *ERCB 2011-002.* Sixty-one of these wells are now operated by other companies. Athabasca has assumed the responsibility for its proportionate share of any abandonment and reclamation associated with the remaining 198 wells. Other items also acquired as part of the transaction and for which Athabasca is now responsible for the associated environmental liability include gas plants, gathering pipelines, several compressor stations, boosters, camps, airstrips and storage areas. Athabasca has budgeted approximately $59.7 million (undiscounted) or $46.3 million (10% discount) for the abandonment and reclamation of the remaining assets in the Liege area.

Costs Incurred During the Year Ended December 31, 2019(1)

Division	Proved Property Acquisition Costs MM($)	Unproved Property Acquisition Costs MM($)	Exploration Costs MM($)	Development Costs MM($)
Light Oil	-	7.0	-	102.7
Thermal Oil	-	-	2.6	89.0
Total	-	7.0	2.6	191.7

Note:

(1) The Light Oil Development Costs amount referred to is gross, the net amount incurred by the Company during 2019 was $43.9 MM after adjusting for the Kaybob Carry Commitment

Exploration and Development Activities[(1)]

The following table summarizes the gross and net exploratory and development wells that were completed by the Company during the year ended December 31, 2019:

	Exploratory		Development		Total	
	Gross	Net	Gross	Net	Gross	Net
Oil wells	2	0.6	5	1.5	7	2.1
Bitumen wells	0	0	1	1	1	1
Gas wells	0	0	14	5.7	14	5.7
Service wells	0	0	10	9.2	10	9.2
Stratigraphic test wells	0	0	0	0	0	0
Dry holes	0	0	0	0	0	0
Total	**2**	**0.6**	**30**	**17.3**	**32**	**17.9**

Note:

(1) Wells are considered to be completed as at the rig-release date for such well. The above well-count also includes any wells that the Company is in a penalty position in relation to.

For a description of the Company's current and likely exploration and development activities see "*Description of Our Business*".

Production Estimates[(1)]

The following table sets out the volumes of Athabasca's working interest production estimated by McDaniel for the year ending December 31, 2020, which is reflected in the estimates of future net revenue disclosed in the tables contained under the headings "*Summary of Net Present Values of Future Net Revenue – Forecast Prices and Costs as of December 31, 2019*", "*Future Net Revenue (Undiscounted) – Forecast Prices and Costs as of December 31, 2019*" and " *Future Net Revenue by Product Type – Forecast Prices and Costs as of December 31, 2019*".

Reserve Category	Bitumen Gross bbl/d	Tight Oil & Light/Medium Crude Oil bbl/d	Conventional Natural Gas mcf/d	Shale Gas mcf/d	Natural Gas Liquids bbl/d	Oil boe/d
GROSS PROVED RESERVES						
Leismer	20,494	0	0	0	0	20,494
Hangingstone	8,128	0	0	0	0	8,128
Greater Placid	0	0	0	22,219	3,054	6,757
Greater Kaybob	0	2,445	0	8,150	228	4,032
TOTAL	**28,622**	**2,445**	**0**	**30,369**	**3,282**	**39,411**
GROSS PROBABLE RESERVES						
Leismer	1,546	0	0	0	0	1,546
Hangingstone	0	0	0	0	0	0
Greater Placid	0	0	0	2,084	348	695
Greater Kaybob	0	54	0	318	9	116
TOTAL	**1,546**	**54**	**0**	**2,402**	**357**	**2,358**

Note:

(1) Totals may not add due to rounding.

Each of the Leismer and Hangingstone assets are estimated to account for greater than 20% of Athabasca's 2020 production volumes. As is shown above, estimated 2020 production volumes for the Leismer assets are 20,494 bbl/d on a Gross Proved Reserves basis and 22,040 bbl/d on a Gross Proved plus Probable Reserves basis and estimated production volumes for the Hangingstone assets are 8,128 bbl/d on a Gross Proved Reserves basis and 8,128 bbl/d on a Gross Proved plus Probable Reserves basis.

Production History [1][2][3][4]

The following table sets forth on a quarterly basis for the year ended December 31, 2019, certain information in respect of production, product prices received, royalties paid, production costs and the resulting netbacks.

	Quarter Ended 2019				Year Ended
	Mar. 31	**June 30**	**Sept. 30**	**Dec. 31**	**Dec. 31, 2019**
Average Daily Production[1]					
Bitumen (bbl/d)	27,494	23,748	25,234	27,761	26,058
Tight Oil (bbl/d)	5,191	4,336	4,719	3,793	4,507
Conventional Natural Gas (Mcf/d)	245	235	234	232	237
NGLs (bbl/d)	1,092	873	811	899	918
Shale Gas (Mcf/d)	32,331	29,770	26,725	23,463	28,044
Total (Boe/d)	39,206	33,958	35,257	36,403	36,196
Average Prices Received[2]					
Bitumen ($/bbl)	42.56	55.58	45.97	38.09	45.29
Tight Oil ($/bbl)	64.15	72.07	65.94	67.38	67.21
Conventional Natural Gas ($/Mcf)	2.66	1.34	0.67	2.00	1.67
NGLs ($/bbl)	39.20	30.09	22.15	27.21	30.28
Shale Gas ($/Mcf)	3.40	2.20	1.69	2.82	2.55
Total ($/boe)	42.25	50.69	43.63	38.61	43.70
Royalties Paid					
Bitumen ($/bbl)	(0.82)	(1.99)	(1.17)	(1.08)	(1.24)
Tight Oil ($/bbl)	(3.42)	(3.27)	(2.82)	(2.85)	(3.11)
Conventional Natural Gas ($/Mcf)	0.17	1.30	0.26	0.15	0.47
NGLs ($/bbl)	(3.32)	(3.05)	(1.99)	(2.79)	(2.83)
Shale Gas ($/Mcf)	0.01	0.33	0.20	(0.02)	0.13
Total ($/boe)	(1.12)	(1.58)	(1.11)	(1.21)	(1.24)
Production Costs[3][4]					
Bitumen ($/bbl)	(23.24)	(26.62)	(23.71)	(24.57)	(24.46)
Tight Oil ($/bbl)	(7.60)	(9.36)	(10.48)	(16.48)	(10.68)
Conventional Natural Gas ($/Mcf)	(1.17)	(1.21)	(1.43)	(2.21)	(1.48)
NGLs ($/bbl)	(8.80)	(8.78)	(10.59)	(14.20)	(10.39)
Shale Gas ($/Mcf)	(2.12)	(2.28)	(2.61)	(3.41)	(2.56)
Total ($/boe)	(19.26)	(21.95)	(20.74)	(22.89)	(21.13)
Netback Received[1]					
Bitumen ($/bbl)	18.50	26.97	21.09	12.44	19.59
Tight Oil ($/bbl)	53.13	59.44	52.64	48.05	53.42
Conventional Natural Gas ($/Mcf)	1.66	1.43	(0.50)	(0.06)	0.66
NGLs ($/bbl)	27.08	18.26	9.57	10.22	17.06
Shale Gas ($/Mcf)	1.29	0.25	(0.72)	(0.61)	0.12
Realized commodity risk management	(5.10)	(4.97)	(2.68)	(0.67)	(3.38)
Total ($/boe)	16.77	22.19	19.10	13.84	17.95

Notes:

(1) Production and netback figures have been presented by accounting month. The netback figures on a per barrel basis have been calculated on sales volumes.

(2) Average realized price received for bitumen has been presented net of the cost of the blended diluent sold.

(3) For wells producing multiple products, production costs have been allocated based on barrels of oil equivalent.

(4) Netbacks are calculated by subtracting royalties and operating and transportation costs from revenues.

The following table sets forth the average daily production from each of the Company's producing fields for the year ended December 31, 2019:

	Bitumen (bbl/d)	**Tight Oil (bbl/d)**	**Conventional Natural Gas (Mcf/d)**	**NGLs (bbl/d)**	**Shale Gas (Mcf/d)**	**Oil Equivalent (boe/d)**
Leismer area	17,565	-	-	-	-	17,565
Hangingstone area	8,493	-	-	-	-	8,493
Greater Kaybob area	-	2,498	-	415	9,271	4,458
Greater Placid area & Other	-	2,009	237	503	18,773	5,680
Total	26,058	4,507	237	918	28,044	36,196

Forward Contracts

From time to time, we enter into financial derivatives to manage our exposure to fluctuations in commodity prices, foreign exchange and interest rates. A description of such instruments is provided in Note 8 of the Company's Annual Consolidated Financial Statements and accompanying Management's Discussion and Analysis for the year ended December 31, 2019 and which can be found on SEDAR at www.sedar.com.

Tax Horizon

For the fiscal year ended December 31, 2019, the Company paid no income tax. The Company does not expect to pay Canadian income taxes during the next five years. This estimate could be affected by, among other factors, income tax reassessments, a significant change in commodity prices or capital activity or the Company's other business activities such as any joint venture arrangements, acquisitions or asset sales. Changes in these factors from estimates used by the Company could result in the Company paying income taxes earlier or later than expected. For additional information concerning the Company's tax horizon see "*Risk Factors – Income Tax"*.

Environmental Considerations

The environmental issues and stakeholder concerns to be managed by Athabasca in developing its assets are similar to those currently being managed by other oil and gas companies, and by communities, and encompass the health of local and regional residents and employees, surface disturbance, effects on traditional land use and historical resources, local and regional air quality, GHG emissions, water quality, monitoring seismic activity levels, health of the aquatic ecosystem in rivers and cumulative effects on wildlife populations and aquatic resources. Athabasca has committed to both site-specific and regional monitoring programs to track the effects of its projects and the cumulative effects of regional development on environmental components and ecosystems.

Athabasca is committed to operating its projects to achieve compliance with applicable statutes, regulations, codes, regulatory approvals and, to the extent practicable, government guidelines. Where the applicable laws are not clear or do not address all environmental concerns, management intends to apply appropriate internal standards and guidelines to address such concerns. In addition to complying with applicable statutes, regulations, codes and regulatory approvals and exercising due diligence, Athabasca strives to continuously improve its operations to address environmental concerns.

DIVIDENDS

Athabasca has not declared or paid any cash dividends on its Common Shares in any of the three most recently completed financial years. We do not currently anticipate paying any cash dividends on our Common Shares but will review that policy from time to time as circumstances warrant. Athabasca currently intends to retain future earnings, if any, for future operations, expansion and possible debt repayment or share repurchases. Any decision to declare and pay dividends in the future will be made at the discretion of the Board and will depend on, among other things, results of operations, current and anticipated cash requirements, financial condition, solvency tests imposed by corporate law, contractual restrictions and financing agreement covenants, including those contained in the 2022 Note Indenture and Amended Credit Facility and other factors that the Board may deem relevant.

Under the terms of the Amended Credit Facility, Athabasca and certain of its subsidiaries are prohibited from making certain distributions, including the payment of dividends. Under the terms of the 2022 Note Indenture, Athabasca and certain of its subsidiaries are prohibited from making certain restricted payments, including the payment of dividends, unless at the time of and immediately after giving effect to such a proposed restricted payment, certain financial tests are met, and no default or event of default under the 2022 Note Indenture has occurred and is continuing.

CAPITAL STRUCTURE

General

Athabasca's authorized share capital consists of an unlimited number of Common Shares without nominal or par value, an unlimited number of first preferred shares, issuable in series, and an unlimited number of second preferred shares, issuable in series, each of which are described below. The Company has also issued the 2022 Notes and has the ability to utilize the Amended Credit Facility and LC Facility that are described below.

As at December 31, 2019, 523,452,277 Common Shares were issued and outstanding and no first preferred shares or second preferred shares were issued and outstanding. In addition, 8,432,067 Stock Options and 15,112,757 RSUs, 5,134,200 Performance Awards and 3,577,464 DSUs were issued and outstanding on December 31, 2019.

Common Shares

Each Common Share entitles the holder thereof to: vote at any meeting of Shareholders of the Company; receive any dividend on the Common Shares declared by the Company; and receive the remaining property of the Company upon dissolution.

Preferred Shares

Subject to the filing of articles of amendment in accordance with the ABCA, the Board may at any time and from time to time issue first or second preferred shares in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the Board. Subject to the filing of articles of amendment in accordance with the ABCA, the Board may from time to time fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of first or second preferred shares including, without limiting the generality of the foregoing: the amount, if any, specified as being payable preferentially to such series on a Distribution (as defined below); the extent, if any, of further participation on a Distribution; voting rights, if any; and dividend rights (including whether such dividends are preferential, cumulative or non-cumulative), if any.

In the event of the voluntary or involuntary liquidation, dissolution or winding up of the Company, or any other distribution of its assets among its Shareholders for the purpose of winding up its affairs (such event referred to herein as a "**Distribution**"), holders of each series of first preferred shares shall be entitled, in priority to holders of Common Shares, second preferred shares and any other shares of the Company ranking junior to the first preferred shares from time to time with respect to payment on a Distribution, to be paid rateably with holders of each other series of first preferred shares the amount, if any, specified as being payable preferentially to the holders of such series on a Distribution.

The 2022 Note Indenture and Amended Credit Facility contain certain restrictions around restricted payments and the issuance of disqualified stock which may limit the Company’s ability to issue first or second preferred shares.

Shareholder Rights Plan

Athabasca’s Shareholder Rights Plan was originally approved by Shareholders at a special meeting held on April 21, 2012. It has been subsequently amended and restated including most recently at the annual general and special meeting that was held on April 6, 2018 (the "**Amended Rights Plan**"). The Shareholders also approved extending the term of the Amended Rights Plan until the 2021 annual general meeting.

The objectives of the Amended Rights Plan are to: (a) ensure, to the extent possible, that all holders of the Common Shares and the Board have adequate time to consider and evaluate any unsolicited take-over bids for the Common Shares; (b) provide the Board with adequate time to identify, solicit, develop and negotiate value-enhancing alternatives, as considered appropriate, to any unsolicited take-over bid; (c) encourage the fair treatment of Athabasca’s shareholders in connection with any unsolicited take-over bid; and (d) generally assist the Board in enhancing shareholder value. The Amended Rights Plan is similar to plans adopted by other Canadian companies.

The Amended Rights Plan encourages a potential acquirer who makes a take-over bid to proceed either by way of a permitted bid, which generally requires a take-over bid to satisfy certain minimum standards designed to promote fairness, or with the concurrence of the Board. If a take-over bid fails to meet these minimum standards, the Amended Rights Plan provides that holders of Common Shares, other than the acquirer, will be able to purchase additional Common Shares at a significant discount to market, thus exposing the acquirer to substantial dilution of its holdings.

A copy of the Amended Rights Plan is available on the Company’s SEDAR profile at *www.sedar.com*.

2022 Notes

On February 24, 2017, Athabasca completed a balance sheet refinancing transaction pursuant to which Athabasca issued 2022 Notes in the amount of US$450 million. The 2022 Notes are due February 24, 2022 and bear interest at a rate of 9.875% per year, payable semi-annually, and are not subject to maintenance or financial covenants. The 2022 Notes are guaranteed on a senior secured basis by Athabasca's material subsidiaries. The 2022 Notes and the guarantees are secured by second-priority security interests (subject to certain liens that are permitted pursuant to the terms of the 2022 Note Indenture) on substantially all of the assets of the Company and the guarantors, with the exception of certain assets that are excluded pursuant to the terms of the 2022 Note Indenture. The 2022 Notes are also subject to the terms of a collateral agent and intercreditor agreement among Athabasca, the guarantors, Bank of New York Mellon and BNY Trust Company of Canada as indenture co-trustees and Computershare Trust Company of Canada dated February 24, 2017 (the "**Collateral Agent Agreement**").

Subject to certain exceptions and qualifications which are set forth in the 2022 Note Indenture, the 2022 Notes limit the ability of the Company and certain of its subsidiaries that are considered to be restricted subsidiaries pursuant to the 2022 Note Indenture to, among other things: make restricted payments; incur additional indebtedness; issue disqualified stock; create or permit liens to exist; create or permit to exist restrictions on the ability of the restricted subsidiaries to make payments and distributions; make certain dispositions and transfers of assets; engage in amalgamations, mergers or consolidations; and engage in certain transactions with affiliates. The 2022 Notes also contain maximum hedging restrictions.

Athabasca may redeem the 2022 Notes at the following specified redemption prices:

- February 24, 2020 to February 23, 2021 - 102.5% of principal
- February 24, 2021 to maturity - 100% of principal

A copy of the 2022 Note Indenture is available on the Company's SEDAR profile at *www.sedar.com*.

Revolving Senior Secured Credit Facility

Concurrent with the issuance of the 2022 Notes, Athabasca entered into an amended and restated $120.0 million reserve-based credit facility (the "**Amended Credit Facility**") with a syndicate of financial institutions to replace Athabasca's previous credit facility. The Amended Credit Facility, which was reaffirmed by the lenders in the fourth quarter of 2019, is a 364-day committed facility available on a revolving basis until May 31, 2020, at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the Amended Credit Facility will be cancelled and any amounts outstanding would be repayable at the end of the non-revolving term, being May 31, 2021. The Amended Credit Facility is subject to a semi-annual borrowing base renewal, occurring in approximately May and November each year. The borrowing base is determined based on the lenders' evaluation of Athabasca's petroleum and natural gas reserves and their commodity price outlook at the time of each renewal, which could result in an increase or a reduction to the Amended Credit Facility.

As at December 31, 2019, amounts borrowed under the Amended Credit Facility bear interest at a floating rate based on the applicable Canadian prime rate, U.S. base rate, LIBOR or bankers' acceptance rate, plus a margin of 2.5% to 3.5% depending on the type of borrowing and Athabasca's indebtedness to EBITDA ratio. Athabasca incurs an issuance fee for letters of credit of 3.5% and incurs a standby fee on the undrawn portion of the Amended Credit Facility of 0.8%.

The Amended Credit Facility does not have any financial covenants and is subject to customary borrowing base provisions. The Amended Credit Facility contains customary negative covenants including those that limit Athabasca's ability to among other things: incur additional indebtedness, create or permit liens to exist and make certain restricted payments, dispositions and transfers of assets and also contains certain maximum hedging requirements. The Amended Credit Facility contains customary positive covenants including, but not limited to, delivery of financial and other information to the lenders, maintenance of existence, payment of taxes and other claims, maintenance of properties and insurance, access to books and records by the lenders, compliance with applicable laws and regulations, including environmental laws, and further assurances and provision of additional collateral and guarantees. The Amended Credit Facility is guaranteed on a senior secured first lien basis and is subject to the terms of the Collateral Agent Agreement.

LC Facilities

On June 17, 2016, Athabasca entered into a demand credit facility (the "**LC Facility**") which provides for the issuance of letters of credit in a principal amount of up to $110.0 million. Effective on that date all letters of credit then issued and outstanding under Athabasca's previous credit facility were deemed to be outstanding under the LC Facility.

Athabasca incurs a fee of 0.25% per annum for letters of credit issued under the LC Facility, subject to a minimum fee of $350. Under the terms of the LC Facility, Athabasca is required to contribute cash to a cash-collateral account equivalent to 101% of the value of all letters of credit issued under the facility.

Athabasca maintains a $30.0 million unsecured letter of credit facility with a Canadian bank which is supported by a performance guarantee from Export Development Canada. The facility is for issuing letters of credit to counterparties and is available on a demand basis. Letters of credit issued under this facility incur an issuance and performance guarantee fee of 2.50%.

CREDIT RATINGS

The following information relating to Athabasca's credit ratings is provided as it relates to Athabasca's financing costs, liquidity and cost of operations. Specifically, credit ratings impact Athabasca's ability to obtain short-term and long-term financing and the cost of such financings. Changes in Athabasca's current credit ratings by its agency, particularly downgrades below the current ratings or negative changes in the ratings outlooks, could adversely affect our cost of borrowing and/or access to sources of liquidity and capital. In addition, changes in credit ratings may affect Athabasca's ability to enter into hedging transactions or other ordinary course contracts on acceptable terms. We are currently rated by S&P.

The following table outlines our credit ratings as of December 31, 2019:

	S&P Ratings Services
Corporate Credit Rating	CCC+
2022 Notes	B
Outlook/Trend	Stable

S&P provide credit ratings of debt securities for commercial entities. A credit rating generally provides an indication of the risk that the borrower will not fulfill its full obligations in a timely manner with respect to both interest and principal commitments. S&P's credit ratings are on a long-term debt rating scale that ranges from AAA to D, which represents the range from highest to lowest quality of such securities rated. The ratings from AA to CCC may be modified by the addition of a plus (+) or a minus (-) sign to show relative standing within the major rating categories. In addition, S&P may add a rating outlook of "positive", "negative" or "stable" which assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years).

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities. Credit ratings are not recommendations to purchase, hold or sell securities and do not address the market price or suitability of a specific security for a particular investor. There is no assurance that any rating will remain in effect for any given period of time or that any rating will not be revised or withdrawn entirely by a rating agency in the future if, in its judgment, circumstances so warrant. A rating can be revised, suspended or withdrawn at any time by the rating agency.

Athabasca paid a fee for service to S&P to provide ratings in respect of the 2022 Notes. Otherwise, no service fees other than annual maintenance fees in respect of the existing credit ratings were paid by the Company to S&P during the preceding two years.

MARKET FOR SECURITIES

Trading Price and Volume

The Common Shares have been listed and posted for trading on the TSX under the symbol "ATH" since April 8, 2010. The following table sets forth the price range and trading volume for the Common Shares on the TSX as reported by the TSX during 2019.

	Price Range		
	High $/share	Low $/share	Volume
December	$0.63	$0.35	55,737,109
November	$0.47	$0.33	44,571,201
October	$0.64	$0.41	28,408,253
September	$0.81	$0.54	37,659,133
August	$0.71	$0.56	25,435,048
July	$0.75	$0.63	19,150,053
June	$0.81	$0.70	26,498,913
May	$1.01	$0.80	46,406,830
April	$1.14	$0.83	71,196,118
March	$0.95	$0.83	45,432,503
February	$0.99	$0.90	23,616,419
January	$1.08	$0.94	52,826,293

Prior Sales

The following is a description of securities of the Company that were issued in the financial year ended December 31, 2019 that are not listed or quoted on a marketplace:

- the Company granted an aggregate of 9,898,000 RSUs to acquire an aggregate of 9,898,000 Common Shares, each with no exercise price;
- the Company granted an aggregate of 1,397,300 Stock Options to acquire an aggregate of 1,397,300 Common Shares, each with an exercise price of $0.85;
- the Company granted an aggregate of 2,800,426 Performance Awards to acquire an aggregate of 2,800,426 Common Shares, each with no exercise price; and
- the Company granted an aggregate of 1,233,975 DSUs.

ESCROWED COMMON SHARES AND COMMON SHARES SUBJECT TO A CONTRACTUAL RESTRICTION ON TRANSFER

As at December 31, 2019, to the best of our knowledge, any Common Shares held in trust are immaterial, representing less than 0.01% of Athabasca's issued and outstanding Common Shares.

DIRECTORS AND OFFICERS

As at the date of filing of this Annual Information Form(5), the names, municipality of residence, positions held with the Company, and principal occupation during the past five years of each of the directors and executive officers of the Company are set out below.

Name and Residence	Position	Principal Occupation During Previous Five Years
Ronald J. Eckhardt(3) Alberta, Canada	Chairman(1) and Director	Mr. Eckhardt is an independent businessman with over forty years of diverse experience in the oil and gas industry including as Executive Vice President, North American Operations of Talisman Energy Inc. Mr. Eckhardt presently also serves on the board of directors and is the Chair of the reserves committee of NuVista Energy Ltd.
Bryan Begley(3)(4) Texas, U.S.A.	Director(1)	Mr. Begley is currently a Managing Director and Partner at 1901 Partners, a private equity firm formed in 2014 to make private investments in the energy sector. Mr. Begley served as a Managing Director of ZBI Ventures, LLC from 2007 to 2014, another private equity firm focused on the energy sector. He began his career as an engineer with Phillips Petroleum Company and was a Partner at McKinsey & Co. in the Houston and Dallas offices where he advised clients across the global energy sector.

Name and Residence	Position	Principal Occupation During Previous Five Years
Anne Downey[3] Alberta, Canada	Director[1]	Ms. Downey brings 40 years of upstream oil and gas experience including as the Vice President Operations at Statoil Canada responsible for oil sands asset development, operations and technology strategy and implementation until 2017. Ms. Downey is an Industry Member appointee to the Alberta Government's Oil Sands Advisory Group and previously held roles at Gulf Canada and Petro-Canada.
Thomas Ebbern[2][4] Alberta, Canada	Director[1]	Mr. Ebbern currently serves as a Strategic Advisor to North West Refining and prior to that was its Chief Financial Officer from 2012 to June, 2019 . Mr. Ebbern also serves as a director on the boards of Hightowers Petroleum Co. and CSV Midstream Solutions. Mr. Ebbern previously served on the board of Talisman Energy Inc.
Carlos Fierro[2][4] Washington D.C., U.S.A.	Director[1]	Since May 2016, Mr. Fierro has served as a senior advisor to Guggenheim Securities, the investment banking arm of Guggenheim Partners. Mr. Fierro also serves on the board of directors and audit and conflicts committee of Shell Midstream Partners, GP LLC. Mr. Fierro was previously Managing Director and Global Head of the Natural Resources Group for Barclays PLC.; the Global Head of the National Resources Group of Lehman Brothers; and a transactional lawyer with Baker Botts LLP.
Marshall McRae[2] Alberta, Canada	Director[1]	Mr. McRae has been an independent financial and management consultant since August 2009. Mr. McRae serves as a director and the Chair of the audit committee of Gibson Energy Inc. Previously, Mr. McRae served as a director of Black Diamond Group Limited and lead director and chair of the audit committee of Source Energy Services Ltd
Robert Broen Alberta, Canada	Director[1], President & Chief Executive Officer	Mr. Broen has been a director and President and Chief Executive Officer of the Company since April 2015. He previously held the roles of Chief Operating Officer of Athabasca and Senior Vice-President, North American Shale at Talisman Energy Inc. and the President and a director of Talisman Energy USA Inc.
Matthew Taylor Alberta, Canada	Chief Financial Officer	Mr. Taylor has been Chief Financial Officer of the Company since November 6, 2019. In the previous five years, he held the position of Vice President, Capital Markets and Communications of the Company. He was the Director of Energy Equity Research at National Bank from July 2010 to April 2014 and held positions in equity research and investment banking at GMP Securities and CIBC World Markets.
Karla Ingoldsby Alberta, Canada	Vice President, Thermal Oil	Ms. Ingoldsby has been Vice President, Thermal Oil of the Company since January 2018. In the previous five years, Ms. Ingoldsby held progressively more senior roles at the Company including Director Thermal Production, Director New Ventures & Land and Director of Thermal Geosciences, Reservoir & Development. She previously held roles at Shell Canada and Royal Dutch Shell Plc.

Name and Residence	Position	Principal Occupation During Previous Five Years
Michael Wojcichowsky Alberta, Canada	Vice President, Light Oil	Mr. Wojcichowsky has been Vice President, Light Oil of the Company since January 2020. In the previous five years, Mr. Wojcichowsky held progressively more senior roles at the Company including Director, Light Oil and will continue to have the additional responsibility for Facilities Engineering and Construction team that spans both Thermal and Light Oil. Mr. Wojcichowsky previously held various senior roles at Talisman Energy Inc.

Notes:

(1) The Company's directors hold office for a term expiring at the conclusion of the next annual meeting of Shareholders of the Company, or until their successors are elected or appointed pursuant to the ABCA and are eligible for re-election. The Company's officers are appointed by and serve at the discretion of the Board.

(2) Member of the Audit Committee. Mr. McRae is the Chair of the Audit Committee.

(3) Member of the Reserves Committee. Ms. Downey is the Chair of the Reserves Committee.

(4) Member of the Compensation and Governance Committee. Mr. Begley is the Chair of the Compensation and Governance Committee.

(5) The information set forth above is current as at the date of the filing of this Annual Information Form (March 4, 2020).

As at December 31, 2019, the directors and executive officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, an aggregate of 3,763,361 Common Shares, representing 0.7% of the issued and outstanding Common Shares (not including any Common Shares issuable pursuant to the exercise of the issued and outstanding Stock Options, RSUs, Performance Awards or DSUs).

Corporate Cease Trade Orders, Bankruptcies, Penalties or Sanctions

To the knowledge of the Company, no current director or executive officer of Athabasca has, within the last ten years prior to the date of this document, been a director, chief executive officer or chief financial officer of any issuer (including the Company) that: (a) while the person was acting in the capacity as director, chief executive officer or chief financial officer, was the subject of a cease trade or similar order or an order that denied the company access to any exemption under securities legislation, that was in effect for a period of more than thirty (30) consecutive days; or (b) was subject to an order that resulted, after the director or executive officer ceased to be a director, chief executive officer or chief financial officer of an issuer, in the issuer being the subject of a cease trade or similar order or an order that denied the relevant issuer access to any exemption under securities legislation, for a period of more than thirty (30) consecutive days, which resulted from an event that occurred while that person was acting as a director, chief executive officer or chief financial officer of the issuer.

To the knowledge of the Company, except as discussed below, no current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, been a director or executive officer of any company (including the Company) 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 for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Mr. Ebbern resigned as a director of Live Out There Inc. on November 6, 2017. Following Mr. Ebbern's resignation, Live Out There Inc. consented to the court appointment of a receiver and manager of its assets, undertakings and properties. The receivership order was granted on November 9, 2017.

No current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has, within the last ten years prior to the date of this document, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or security-holder.

To the knowledge of the Company, no current director or executive officer or security-holder holding a sufficient number of securities of the Company to affect materially the control of the Company has been subject to: (a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (b) 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.

Conflicts of Interest

Certain of Athabasca's directors and officers are engaged in, and may continue to be engaged in, other activities in the oil and natural gas industry from time to time. As a result of these and other activities, certain directors and officers of the Company may become subject to conflicts of interest from time to time. The ABCA provides that in the event that an officer or director is a party to, or is a director or an officer of, or has a material interest in any person who is a party to, a material contract or material transaction or proposed material contract or proposed material transaction, such officer or director shall disclose the nature and extent of his or her interest and shall refrain from voting to approve such contract or transaction, unless otherwise provided under the ABCA. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of the ABCA.

As of the date hereof, we are not aware of any existing or potential material conflicts of interest between Athabasca or a subsidiary of Athabasca and any our directors or officers.

LEGAL PROCEEDINGS

There are no legal proceedings involving claims for damages for which the potential exposure is more than 10% of our current assets to which we are or was a party, or in respect of which any of our property is or was the subject of, during the most recently completed financial year, nor are there any such material legal proceedings that the Company knows to be contemplated.

During the year ended December 31, 2019, there were: (a) no penalties or sanctions imposed against us by a court relating to securities legislation or by a securities regulatory authority; (b) no other penalties or sanctions imposed by a court or regulatory body against us that we believe would likely be considered important to a reasonable investor in making an investment decision; and (c) no settlement agreements entered into by us with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed below, or as may be disclosed elsewhere in this Annual Information Form, none of our directors, officers or principal shareholders, and no associate or affiliate of any of them, has or has had any material interest in any transaction or any proposed transaction which has materially affected or is reasonably expected to materially affect us or any of our affiliates.

A portion of the consideration for the Leismer Corner Assets was comprised of 100 million Common Shares issued to Statoil. As at December 31, 2019, Statoil held approximately 19.1% of the issued and outstanding Common Shares. See "*Development of Our Business – Developments in 2017*".

TRANSFER AGENTS AND REGISTRARS

Computershare Trust Company of Canada at its office in Calgary, is the transfer agent and registrar for the Common Shares.

MATERIAL CONTRACTS

As at December 31, 2019, the following were the only material contracts, other than those contracts entered into in the ordinary course of business, which the Company or any of its subsidiaries has entered into within the most recently completed financial year, or before the most recently completed financial year and which were still in effect as of December 31, 2019:

- the Purchase and Sale Agreement with Enbridge referred to under the heading "*Development of Our Business – Developments in 2018*";
- the Rights Plan referred to under the heading "*Capital Structure – Shareholder Rights Plan*";
- the Placid JDA (entered into May 13, 2016). See definition of "*Placid JDA*";

- the Kaybob JDA (entered into May 13, 2016). See definition of "*Kaybob JDA*";
- the Acquisition Royalty. See "*Development of Our Business – Developments in 2017*";
- the Royalty. See definition of "*Royalty*";
- the 2022 Note Indenture. See "*Capital Structure – 2022 Notes*";
- the Amended Credit Facility. See "*Capital Structure - Revolving Senior Secured Credit Facility*"; and
- the LC Facility. See "*Capital Structure - LC Facilities*".

Copies of these material contracts are available for review on the Company's SEDAR profile at www.sedar.com.

INTEREST OF EXPERTS

Names of Experts

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a report, valuation, statement or opinion described or included in a filing, or referred to in a filing, made under NI 51-102 by the Company during, or relating to the Company's most recently completed financial year other than McDaniel, our independent engineering evaluator, and Ernst & Young LLP, our independent auditor.

Interests of Experts

We used Ernst & Young LLP for external audit services for the fiscal year ended December 31, 2019. Ernst & Young LLP are our auditors and have confirmed that they are independent with respect to us within the meaning of the relevant rules and related interpretations prescribed by the relevant professional bodies in Canada and any applicable legislation or regulations.

Reserve estimates by McDaniel are included in this Annual Information Form. None of the designated professionals of McDaniel have any registered or beneficial interests, direct or indirect, in any of our securities or other property or of our associates or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of us or of any of our associates or affiliates.

AUDIT COMMITTEE

Audit Committee Mandate and Terms of Reference for Chair

The Board's written mandate for the Audit Committee, which sets out the Audit Committee's responsibilities, is attached to this Annual Information Form as Appendix "D".

Composition of the Audit Committee and Relevant Education and Experience

The members of our Audit Committee are Marshall McRae (chair), Carlos Fierro and Thomas Ebbern. Each of the members of the Audit Committee are "independent" and "financially literate" within the meaning of NI 52-110.

Mr. McRae has been an independent financial and management consultant since August 2009. Mr. McRae has over 30 years of experience in senior operating and financial management positions with a number of publicly traded and private companies, including CCS Inc., Versacold Corporation and Mark's Work Wearhouse Limited. Mr. McRae is a director and the Chair of the audit committee of Gibson Energy Inc. and previously was a director of Black Diamond Group Limited and was also previously the lead director and chair of the audit committee of Source Energy Services Ltd. Mr. McRae obtained a Bachelor of Commerce degree, with Distinction, from the University of Calgary in 1979, and a Chartered Accountant designation from the Institute of Chartered Accountants of Alberta in 1981.

Since May 2016, Mr. Fierro has served as a senior advisor to Guggenheim Securities, the investment banking arm of Guggenheim Partners. Mr. Fierro serves on the board of directors, audit and conflicts committee of Shell Midstream

Partners. Mr. Fierro was previously Managing Director and Global Head of the Natural Resources Group for Barclays PLC and Global Head of the National Resources Group at Lehman Brothers. Before joining Lehman Brothers, Mr. Fierro was a transactional lawyer with Baker Botts LLP., where he practiced corporate, M&A and securities law. Mr. Fierro obtained a Bachelor of Arts degree from the University of Notre Dame in 1983 and a Juris Doctor from Harvard University in 1986.

Mr. Ebbern has been with North West Refinancing since 2012, initially serving as Chief Financial Officer until June 2019 and now as Strategic Advisor. Mr. Ebbern currently serves as a director on the boards of Hightowers Petroleum Co. and CSV Midstream Solutions and has previously served as a director on the boards of both Nexen Inc. and Talisman Energy Inc. He obtained a Bachelor of Science in Engineering from Queens University in 1982 and Masters of Business Administration from the Ivey Business School at Western University in 1989.

Audit Committee Oversight

At no time since the commencement of Athabasca's most recently completed financial year has a recommendation of the Audit Committee to nominate or compensate an external auditor not been adopted by the Board.

Pre-Approval Policies and Procedures for the Engagement of Non-Audit Services

The Audit Committee must pre-approve and disclose, as required, the retention of the external auditor for non-audit services to be provided to the Company or any of its subsidiaries that is permitted under applicable law. In the discretion of the Audit Committee, it may annually delegate to one or more of its independent members or to management the authority to grant pre-approvals for the provision of non-audit services; subject to, in the case of any such delegation to management, the subsequent ratification by the Audit Committee.

Auditors' Fees (1)(2)(3)(4)

The following table summarizes the fees paid by the Company to its auditors, Ernst & Young LLP, for external audit and other services in the last two fiscal years.

Nature of Services	Fees Paid to Auditor in Year Ended December 31, 2019 ($)	Fees Paid to Auditor in Year Ended December 31, 2018 ($)
Audit Fees(1)	417,300	342,500
Audit-Related Fees(2)	106,500	17,000
Tax Fees(3)	57,155	79,987
All Other Fees(4)	0	57,862
Total	580,955	497,349

Notes:

(1) "**Audit Fees**" means billings for professional services rendered by the issuer's external auditor for the audit and review of the issuer's financial statements or services that are normally provided by the external auditor in connection with statutory and regulatory filings or engagements.

(2) "**Audit-Related Fees**" means billings for assurance and related services that are reasonably related to the performance of the audit or review of the issuer's financial statements, but not reported as audit fees.

(3) "**Tax Fees**" means billings for professional services for tax compliance, tax advice, and tax planning.

(4) "**All Other Fees**" means fees not meeting the fee classifications above. The amounts shown in All Other Fees for the year ended December 31, 2018 primarily relate to administrative surcharges and other outlays charged by Ernst & Young LLP.

INDUSTRY CONDITIONS

Companies carrying on business in the crude oil and natural gas sector in Canada are subject to extensive controls and regulations imposed through legislation of the federal government and the provincial governments in the jurisdictions where the companies have assets or operations. While such regulations do not affect our operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although laws and regulations are a matter of public record, we are unable to predict what additional laws, regulations or amendments governments may enact in the future.

We hold interests in oil and gas properties along with related assets in Alberta. Our assets and operations are regulated by administrative agencies deriving authority from underlying legislation enacted by the applicable level of government. Regulated aspects of our upstream crude oil and natural gas business include all manner of activities associated with the exploration for and production of crude oil and natural gas, including, among other matters: (i) permits for the drilling of wells; (ii) technical drilling and well requirements; (iii) permitted locations and access of operation sites; (iv) operating standards regarding conservation of produced substances and avoidance of waste, such as restricting flaring and venting; (v) minimizing environmental impacts; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct crude oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in western Canada.

Pricing and Marketing

Crude Oil

Producers of crude oil and crude bitumen are entitled to negotiate sales contracts directly with purchasers. As a result, macroeconomic and microeconomic market forces determine the price of oil. Worldwide supply and demand factors are the primary determinant of oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on oil quality, prices of competing fuels, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Natural Gas

Negotiations between buyers and sellers determines the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms. Spot and future prices can also be influenced by supply and demand fundamentals on various trading platforms.

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms.

Exports from Canada

On August 28, 2019, Bill C-69 came into force, replacing, among other things, the *National Energy Board Act* (the "**NEB Act**") with the *Canadian Energy Regulator Act* (Canada) (the "**CERA**"), and replacing the National Energy Board (the "**NEB**") with the Canadian Energy Regulator ("**CER**"). The CER has assumed the NEB's responsibilities broadly, including with respect to the export of crude oil, natural gas and NGLs from Canada. The legislative regime relating to exports of crude oil, natural gas and NGL from Canada has not changed substantively under the new regime.

Exports of crude oil, natural gas and NGLs from Canada are subject to the CERA and remain subject to the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). While the Part VI Regulation was enacted under the NEB Act, it will remain in effect until 2022, or until new regulations are made under the CERA. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. For natural gas, the maximum duration of an export licence is 40 years; for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. To obtain a crude oil export licence, a mandatory public hearing with the CER is required; however, there is no public hearing requirement for the export of natural gas and NGLs. Instead, the CER will continue to apply the NEB's written process that includes a public comment period for impacted persons. Following the comment period, the CER completes its assessment of the application and either approves or denies the application. The CER can approve an application if it is satisfied that proposed export volumes are not greater than Canada's reasonably foreseeable needs, and if the proposed exporter is in compliance with the CERA and all associated regulations and orders made under the CERA. Following the CER's approval of an export licence, the federal Minister of Natural Resources is mandated to give his or her final approval. While the Part VI Regulation remains in effect, approval of the cabinet of the Canadian federal government ("**Cabinet**") is also required. The discretion of the Minister of Natural Resources and Cabinet will be framed by the Minister of Natural Resources' mandate to implement the CERA safely and efficiently, as well as the purpose of the CERA, to effect "oil and natural gas exploration and exploitation in a manner that is safe and secure and that protects people, property and the environment".

The CER also has jurisdiction to issue orders that provide a short-term alternative to export licences. Orders may be issued more expediently, since they do not require a public hearing or approval from the Minister of Natural Resources or Cabinet. Orders are issued pursuant to the Part VI Regulation for up to one or two years depending on the substance, with the exception of natural gas (other than NGLs) for which an order may be issued for up to twenty years for quantities not exceeding 30,000 m^3 per day.

As to price, exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. The Company does not directly enter into contracts to export its production outside of Canada.

As discussed in more detail below, one major constraint to the export of crude oil, natural gas and NGLs outside of Canada is the deficit of overall pipeline and other transportation capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation projects are underway, many contemplated projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Major pipeline and other transportation infrastructure projects typically require a significant length of time to complete once all regulatory and other hurdles have been cleared. In addition, production of crude oil, natural gas and NGLs in Canada is expected to continue to increase, which may further exacerbate the transportation capacity deficit.

Transportation Constraints and Market Access

Pipelines

Producers negotiate with pipeline operators (or other transport providers) to transport their products to market on a firm or interruptible basis. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers that can be reached in a cost-effective manner and the price received. Due to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced low commodity pricing relative to other markets in the last several years.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require a regulatory review and approval by Cabinet. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. The federal government amended the federal approval process with the CER, which aims to create efficiencies in the project approval process while upholding stringent environmental and regulatory standards. However, as the CER has not yet undertaken a major project approval, it is unclear how the new regulator operates compared to the NEB and whether it will result in a more efficient approval process. Lack of regulatory certainty is likely to influence investment decisions for major projects. Even when projects are approved on a federal level, such projects often face further delays due to interference by provincial and municipal governments. Additional delays causing further uncertainty result from legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples, and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines require approvals of several levels of government in the United States.

In the face of such regulatory uncertainty, the Canadian crude oil and natural gas industry has experienced significant difficulty expanding the existing network of transportation infrastructure for crude oil, natural gas and NGLs, including pipelines, rail, trucks and marine transport. Improved access to global markets through the Midwest United States and export shipping terminals on the west coast of Canada could help to alleviate downward pressure on commodity prices. Several proposals have been announced to increase pipeline capacity from Western Canada to Eastern Canada, the United States, and other international markets via export terminals. While certain projects are proceeding, the regulatory approval process and other factors related to transportation and export infrastructure have led to the delay, suspension or cancellation of a number of pipeline projects.

With respect to the current state of the transportation and exportation of crude oil from Western Canada to domestic and international markets, the Enbridge Line 3 Replacement from Hardisty, Alberta, to Superior, Wisconsin, formerly expected to be in-service in late 2019, continues to experience permitting difficulties in the United States and is now expected to be in-service in the latter half of 2020. The Canadian portion of the replaced pipeline began commercial operation on December 1, 2019.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of sustained political opposition in British Columbia, the federal government purchased the Trans Mountain Pipeline from Kinder Morgan Cochin ULC in August 2018. However, the Trans Mountain Pipeline expansion experienced a setback when, in August 2018, the Federal Court of Appeal identified deficiencies in the NEB's environmental assessment and the Government's Indigenous consultations. The Court quashed the accompanying certificate of public convenience and necessity and directed Cabinet to correct these deficiencies. On June 18, 2019, Cabinet re-approved the Trans Mountain Pipeline expansion and directed the NEB to issue a certificate of public convenience and necessity for the project. Ongoing opposition by Indigenous groups continues to affect the progress of the Trans Mountain Pipeline. Along with its approval of the expansion, the federal government also announced the launch of the first step of a multi-step process of engagement with Indigenous groups for potential Indigenous economic participation in the pipeline. Following a public comment period initiated after the approval, the NEB ruled that NEB decisions and orders issued prior to the Federal Court of Appeal decision quashing the original Certificate of Public Convenience and Necessity will remain valid unless the CER (having replaced the NEB) decides that relevant circumstances have materially changed, such that there is a doubt as to the correctness of a particular decision or order. Construction commenced on the Trans Mountain Pipeline in late 2019 and is proceeding concurrently alongside CER hearings with landowners and affected communities to determine the final route for the Trans Mountain Pipeline.

In December 2019, the Federal Court of Appeal heard a judicial review application brought by six Indigenous applicants challenging the adequacy of the federal government's further consultation on the Trans Mountain Pipeline expansion. Two First Nations subsequently withdrew from the litigation after reaching a deal with Trans Mountain. On February 4, 2020, the Federal Court of Appeal dismissed the remaining four appellants' application for judicial review, upholding Cabinet's second approval of the Trans Mountain Pipeline expansion from June 2019.

In addition, on April 25, 2018, the British Columbia Government submitted a reference question to the British Columbia Court of Appeal, seeking to determine whether it has the constitutional jurisdiction to amend the *Environmental Management Act* (the "**BC EMA**") to impose a permitting requirement on carriers of heavy crude within British Columbia. The British Columbia Court of Appeal answered the reference question unanimously in the negative, and on January 16, 2020, the Supreme Court of Canada heard the Attorney General of British Columbia's appeal. The Supreme Court of Canada unanimously dismissed the appeal and adopted the reasons of the British Columbia Court of Appeal. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – British Columbia*".

While it was expected that construction on the Keystone XL Pipeline, owned by the Canadian company TC Energy Corporation ("**TC Energy**") would commence in the first half of 2019, pre-construction work was halted in late 2018 when a United States Federal Court judge determined the underlying environmental review was inadequate. The United States Department of State issued its final Supplemental Environmental Impact Statement in late 2019, and in January 2020, the United States Government announced its approval of a right-of-way that would allow the Keystone XL Pipeline to cross 74 kilometers of federal land. TC Energy announced in January 2020 that it plans to begin mobilizing heavy equipment for pre-construction work in February 2020, and that work on pipeline segments in Montana and South Dakota will begin in August 2020. Nevertheless, the Keystone XL pipeline remains subject to legal and regulatory barriers. In December 2019, a federal judge in Montana rejected the United States Government's request to dismiss a lawsuit by Native American tribes attempting to block required pipeline permits. The tribes claim that a permit issued in March 2019 would allow the pipeline to disturb cultural sites and water supplies in violation of tribal laws and treaties. Furthermore, the 1.9-kilometer long segment of the pipeline that will cross the Canada-United States Border remains dependant on the receipt of a grant of right-of-way and temporary use permit from the United States Bureau of Land Management and other related federal land authorizations.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act*, which imposes a ban on tanker traffic transporting certain crude oil and NGLs products in excess of 12,500 metric tones to or from British Columbia's north coast. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Federal*".

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/day of crude oil out of the province to help alleviate the high price differential plaguing Canadian oil prices. The Alberta Petroleum Marketing Commission would purchase crude oil from producers and market it, using the expanded rail capacity to transport the marketed oil to purchasers. However, in the spring of 2019, the Government of Alberta indicated that the rail program will be cancelled by assigning the transportation contracts to industry proponents and in February 2020, the Government of Alberta announced that it is finalizing the sale of the contracts.

Natural Gas

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which in the last several years has generally been depressed (at times producers have received negative pricing for their natural gas production).

Required repairs or upgrades to existing pipeline systems have also led to further reduced capacity and apportionment of firm access, which in Western Canada may be further exacerbated by natural gas storage limitations. However, in September 2019, the CER approved a policy change by TC Energy on its NOVA Gas Transmission Ltd. pipeline network (which carries much of Alberta's gas production) to give priority to deliveries into storage. The change has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system. January 2020 has seen the narrowest price differential between Canadian and United States natural gas benchmarks since early 2019.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, with 24 export licences issued since 2011, government decision-making, regulatory uncertainty, opposition from environmental and Indigenous groups, and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the proponents of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project. Pre-construction activities began in November 2018, with a planned completion target of 2025. In December 2019, the CER approved a 40-year export licence for the Kitimat LNG project, a proposed joint venture between Chevron Canada Limited and Woodside Energy International (Canada Limited), a subsidiary of Australian Energy Ltd. This licence remains subject to Cabinet approval, and Chevron Canada Limited has indicated that it is interested in selling its 50 percent interest in Kitimat LNG. The Woodfibre LNG Project is a small-scale LNG processing and export facility near Squamish, British Columbia. The BC Oil and Gas Commission approved a project permit for Woodfibre LNG, a subsidiary of Singapore-based Pacific Oil and Gas Ltd. in July 2019. Pre-construction agreements for Woodfibre LNG are in the process of being finalized. A project by GNL Québec Inc. is working through the federal impact assessment process for the construction and operation of a LNG facility and export terminal located on Saguenay Fjord, an inlet which feeds into the St. Lawrence River. The Goldboro LNG project, located in Nova Scotia, proposed by Pieridae Energy Ltd., would see LNG exported from Canada to European markets. Pieridae has agreements with Shell, upstream, and with Uniper, a German utility, downstream. The federal government has issued Goldboro LNG a 20-year export licence, and Pieridae Energy Ltd. has forecast a positive final investment decision for 2020. The Cedar LNG Project near Kitimat by Cedar LNG Export Development Ltd. is currently in the environmental assessment stage, with British Columbia's Environmental Assessment Office conducting the environmental assessment on behalf of the Impact Assessment Agency of Canada ("**IA Agency**").

Enbridge Open Season

In early August 2019, Enbridge initiated an open season for the Enbridge mainline system, which has historically operated as a common carrier pipeline system, wherein producers could nominate volumes to ship through the pipeline. The changes that Enbridge intends to implement in the open season include the transition of the mainline system from a common carrier to a primarily contract carrier pipeline, wherein producers will have to commit to reserved space in the pipeline for a fixed term, with only 10% of available capacity reserved for nominations. As a result, shippers seeking firm capacity on the Enbridge system would no longer be able to rely on the nomination process and would have to enter long-term contracts for service.

Several shippers challenged Enbridge's open season and, in particular, Enbridge's ability to engage in an open season without prior regulatory approval. Following an expedited hearing process, the CER decided to shut down the open season, citing concerns about fairness and uncertainty regarding the ultimate terms and conditions of service.

On December 19, 2019, Enbridge applied to the CER for a hearing for the right to hold an open season. The CER is expected to establish a timeline for the process in early 2020. Interveners will have the opportunity to make written submissions, and then an oral hearing will take place later in the year. A final decision from the CER is expected in early 2021.

Curtailment

On December 2, 2018, the Government of Alberta announced that, commencing January 1, 2019, it would mandate a short-term reduction in provincial crude oil and crude bitumen production. As contemplated in the *Curtailment Rules*, as amended effective October 1, 2019, the Government of Alberta, on a monthly basis, subjects crude oil producers producing more than 20,000 bbl/d to curtailment orders that limit their production according to a pre-determined formula that allocates production limits proportionately amongst all operators subject to curtailment orders.

Where an operator to whom a curtailment order applies is a joint venture or partnership, the partners or joint ventures may enter into an agreement respecting the allocation of the combined production among themselves to comply with the curtailment order.

Curtailment first took effect on January 1, 2019, limiting province-wide production of crude oil and crude bitumen to 3.56 million bbls/d. The curtailment rate dropped gradually over the course of 2019 as a result of decreasing price differentials and volumes of crude oil and crude bitumen in storage. Allowable production for December 2019, January 2020 and February 2020 is set at 3.81 million bbl/d.

The Government of Alberta introduced certain policy changes to the curtailment program in late 2019, including giving the Minister of Energy the power to set revised production limits for a producer following a merger or acquisition, and creating an exemption for newly drilled conventional oil wells. Furthermore, the Government of Alberta created a special production allowance, effective October 28, 2019, that allows crude oil production in excess of a curtailment order, provided that the extra production is shipped out of Alberta by rail.

Curtailment volumes affect sixteen of over 300 producers in Alberta, including Athabasca. The *Curtailment Rules* are set to be repealed by December 31, 2020.

NAFTA, USMCA and Other Trade Agreements

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. The three NAFTA signatories have been working towards replacing NAFTA. On November 30, 2018, Canada, Mexico, and the United States signed a new trade agreement, widely referred to as the United States Mexico Canada Agreement (the "**USMCA**"), sometimes referred to as the Canada United States Mexico Agreement, or "**CUSMA**". Legislative bodies in the three signatory countries must ratify the USMCA before it comes into force. Mexico's senate ratified the USMCA in June 2019. In late December 2019, the United States' House of Representatives approved the USMCA, and the USMCA received approval from the United States Senate on January 16, 2020. On January 29, 2020, the Government of Canada tabled Bill C-4 to ratify the USMCA. According to Bill C-4, the USMCA will come into force two months after the House of Commons and the Senate pass Bill C-4. Until then, NAFTA remains the North American trade agreement currently in force. As the United States remains Canada's primary trading partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada the implementation of the final version ratified version of the USMCA could have an impact on Western Canada's crude oil and natural gas industry at large, including the Company's business.

Under the terms of NAFTA's Article 605, a proportionality clause prevents Canada from implementing policies that limit exports to the United States and Mexico, relative to the total supply produced in Canada. Canada remains free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of goods of Canada as compared to the proportion prevailing in the most recent 36 month period; (ii) impose an export price higher than the domestic price (subject to an exception with respect to certain measures which only restrict the volume of exports); and (iii) disrupt normal channels of supply. Further, all three signatory countries are prohibited from imposing a minimum or maximum price requirement on exports (where any other form of quantitative restriction is prohibited) and imports (except as permitted in the enforcement of countervailing and anti-dumping orders and undertakings). NAFTA also requires energy regulators to ensure the orderly and equitable implementation of any regulatory changes and to ensure that the application of such changes will cause minimal disruption to contractual arrangements and avoid undue interference with pricing, marketing and distribution arrangements.

The Government of Alberta's curtailment program complies with NAFTA's Article 605, under which Canada must make available a consistent proportion of the crude oil and bitumen produced to the other NAFTA signatories. As a result of the proportionality rule, reducing Canadian supply reduced the required offering under NAFTA, with the result that the amount of crude oil and bitumen that Canada is required to offer, while Canadian crude oil prices are depressed, may be reduced. It is possible that the USMCA will come into force before the Government of Alberta's curtailment order is set to be repealed by the end of 2020.

The USMCA does not contain the proportionality rules of NAFTA's Article 605. The elimination of the proportionality clause removes a barrier in Canada's transition to a more diversified export portfolio. While diversification depends on the construction of infrastructure allowing more Canadian production to reach Eastern Canada, Asia, and Europe, the USMCA may allow for greater export diversification than currently exists under NAFTA.

Other Trade Agreements

Canada has also pursued a number of other international free trade agreements with other countries around the world. As a result, a number of free trade or similar agreements are in force between Canada and certain other countries while in other circumstances Canada has been unsuccessful in its efforts. Canada and the European Union recently agreed to the Comprehensive Economic and Trade Agreement ("**CETA**"), which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Although CETA remains subject to ratification by 14 of the 28 national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In light of the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada are expected to work towards a new trade agreement through the 11-month implementation period, during which the United Kingdom will transition out of the European Union. As such, CETA will remain in place until December 31, 2020.

Canada and ten other countries have agreed on the text of the Comprehensive and Progressive Agreement for Trans-Pacific Partnership ("**CPTPP**"), which is intended to allow for preferential market access among the countries that are parties to the CPTPP. The CPTPP is in force among the first seven countries to ratify the agreement – Canada, Australia, Japan, Mexico, New Zealand, Vietnam, and Singapore.

While it is uncertain what effect CETA, CPTPP, or any other trade agreements will have on the crude oil and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

Land Tenure

The respective provincial governments (i.e. the Crown) predominantly own the mineral rights to crude oil and natural gas located in western Canada, with the exception of Manitoba (which only owns 20% of the mineral rights). Provincial governments grant rights to explore for and produce crude oil and natural gas pursuant to leases, licences and permits for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments. The provincial governments in western Canada's provinces conduct regular land sales where crude oil and natural gas companies bid for leases to explore for and produce crude oil and natural gas pursuant to mineral rights owned by the respective provincial governments. Oil and natural gas leases generally have a fixed term; however, a lease may generally be continued after the initial term where certain minimum thresholds of production have been reached, all lease rental payments have been paid on time and other conditions are satisfied.

To develop crude oil and natural gas resources, it is necessary for the mineral estate owner to have access to the surface lands as well. Each province has developed its own process for obtaining surface access to conduct operations that operators must follow throughout the lifespan of a well, including notification requirements and providing compensation for affected persons for lost land use and surface damage.

Each of the provinces of western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a lease or licence. Additionally, the provinces of Alberta and British Columbia have shallow rights reversion for shallow, non-productive geological formations for new leases and licences.

In addition to Crown ownership of the rights to crude oil and natural gas, private ownership of crude oil and natural gas (i.e. freehold mineral lands) also exists in western Canada. In the provinces of Alberta, British Columbia, Saskatchewan and Manitoba approximately 19%, 6%, 20% and 80%, respectively, of the mineral rights are owned by private freehold owners. Rights to explore for and produce such crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and crude oil and natural gas explorers and producers.

An additional category of mineral rights ownership includes ownership by the Canadian federal government of some legacy mineral lands and within Indigenous reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada ("**IOGC**"), which is a federal government agency, manages subsurface and surface leases, in consultation with the applicable Indigenous peoples, for exploration and production of crude oil and natural gas on Indigenous reservations.

Until recently, oil and natural gas activities conducted on Indian reserve lands were governed by the *Indian Oil and Gas Act* (the "**IOGA**") and the *Indian Oil and Gas Regulations, 1995* (the "**1995 Regulations**"). In 2009, Parliament passed *An Act to Amend the Indian Oil and Gas Act*, amending and modernizing the IOGA (the "**Modernized IOGA**"), however the amendments were delayed until the federal government was able to complete stakeholder consultations and update the accompanying Regulations (the "**2019 Regulations**"). The Modernized IOGA and the 2019 Regulations came into force on August 1, 2019. At a high level, the Modernized IOGA and the 2019 Regulations govern both surface and subsurface IOGC Leases, establishing the terms and conditions with which an IOGC leaseholder must comply. The two enactments also establish a substitution system whereby provincial oil and natural gas/environmental regulatory authorities act on behalf of the federal government to ensure greater symmetry between federal and provincial regulatory standards. The Company does not have operations on Indian reserve lands.

Royalties and Incentives

General

Each province has legislation and regulations that govern royalties, production rates and other matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGLs production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes and royalties. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable typically depends in part on prescribed reference prices, well productivity, geographic location, field discovery date, method of recovery and the type or quality of the petroleum substance produced.

Occasionally the governments of western Canada's provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. In addition, such programs may be introduced to encourage producers to undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGLs.

In addition, the federal government may from time to time provide incentives to the oil and natural gas industry. In November of 2018, the federal government announced its plans to implement an accelerated investment incentive, aimed to provide oil and natural gas businesses with eligible Canadian development expenses ("**CDE**")[1] and Canadian

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[1] Drilling and completion costs are generally included in CDE and deductible at a rate of 30% per year, on a declining balance basis.

oil and gas property expenses ("**COGPE**")[2] with a first year deduction of one and a half times the deduction that is otherwise available for CDE. The definitions of "accelerated CDE" and "accelerated COGPE", as amended in November 2018, allow oil and natural gas businesses to claim an additional 15% deduction for new CDE, and an additional 5% deduction for new COGPE for taxation years that end before 2024 if such CDE or COGPE was incurred after November 20, 2018. The acceleration is reduced to 7.5% for new CDE and 2.5% for new COGPE for taxation years that begin after 2023 and end before 2028. Successored expenses, and costs in respect of Canadian resource properties not acquired at arms' length, will not qualify for treatment as accelerated CDE or accelerated COGPE.

The federal government also announced in late 2018 that it would make $1.6 billion available to the oil and natural gas industry in light of worsening commodity price differentials. The aid package has been administered through federal agencies including the Business Development Bank of Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada. Export Development Canada has lent or guaranteed $629 million among 37 companies, of $1 billion available to oil and natural gas producers. The Bank of Canada has made 892 loans totalling $207.5 million out of its $500-million commercial loan allotment in the aid package. Innovation, Science and Economic Development Canada announced $49 million each for two projects to help Alberta companies building facilities to turn propane into polypropylene, a type of plastic not currently produced in Canada, but often used in packaging and labels. Natural Resources Canada distributed $37 million of a $50-million commitment under its Clean Growth Program for nine projects that help oil and natural gas companies reduce their carbon footprints.

Producers and working interest owners of crude oil and natural gas rights may also carve out additional royalties or royalty-like interests through non-public transactions, which include the creation of instruments such as overriding royalties, net profits interests and net carried interests.

Alberta

In Alberta, the provincially-set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized Alberta royalty framework (the "Modernized Framework") that applies to all wells drilled after December 31, 2016. The previous royalty framework (the "Old Framework") will continue to apply to wells drilled prior to January 1, 2017 for a period of ten years ending on December 31, 2026. After the expiry of this ten-year period, these older wells will become subject to the Modernized Framework. The *Royalty Guarantee Act (Alberta),* came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

The Modernized Framework applies to all hydrocarbons other than oil sands which will remain subject to their existing royalty regime. Royalties on production from non-oil sands wells under the Modernized Framework are determined on a "revenue-minus-costs" basis with the cost component based on a Drilling and Completion Cost Allowance formula for each well, depending on its vertical depth and/or horizontal length. The formula is based on the industry's average drilling and completion costs as determined by the AER on an annual basis.

Producers pay a flat royalty rate of 5% of gross revenue from each well that is subject to the Modernized Framework until the well reaches payout. Payout for a well is the point at which cumulative gross revenues from the well equals the Drilling and Completion Cost Allowance for the well set by the AER. After payout, producers pay an increased post-payout royalty on revenues of between 5% and 40% for crude oil and pentanes and 5% and 36% for methane, ethane, propane and butane, all determined by reference to the then current commodity prices of the various hydrocarbons. Similar to the Old Framework, the post-payout royalty rate under the Modernized Framework varies with commodity prices. Once production in a mature well drops below a threshold level where the rate of production is too low to sustain the full royalty burden, its royalty rate is adjusted downward towards a minimum of 5% as the mature well's production declines. As the Modernized Framework uses deemed drilling and completion costs in calculating the royalty and not the actual drilling and completion costs incurred by a producer, low cost producers benefit if their well costs are lower than the Drilling and Completion Cost Allowance and, accordingly, they continue to pay the lower 5% royalty rate for a period of time after their wells achieve actual payout.

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[2] COGPE generally includes intangible costs associated with the acquisition of Canadian resource properties and is deductible at a rate of 10% per year on a declining balance basis.

Oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly, and producers must submit their records showing the royalty calculation. The *Mines and Minerals Act* was amended in 2014 and shortened the window during which producers can submit amendments to their royalty calculations before they become statute-barred, from four years to three. Both the 2014 and 2015 production years became statute barred on December 31, 2018 as the pre-amendment four-year period applied for the years up to and including 2014. Going forward, producers will only have three years to amend their royalty calculations.

The Old Framework is applicable to all conventional crude oil and natural gas wells drilled prior to January 1, 2017 and bitumen production. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for conventional crude oil production under the Old Framework range from a base rate of 0% to a cap of 40%. Subject to certain available incentives, effective from the January 2011 production month, royalty rates for natural gas production under the Old Framework range from a base rate of 5% to a cap of 36%. The Old Framework also includes a natural gas royalty formula which provides for a reduction based on the measured depth of the well below 2,000 metres deep, as well as the acid gas content of the produced gas. Under the Old Framework, the royalty rate applicable to NGLs is a flat rate of 40% for pentanes and 30% for butanes and propane. Currently, producers of crude oil and natural gas from Crown lands in Alberta are required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

Oil sands production is also subject to Alberta's royalty regime. The Modernized Framework did not change the oil sands royalty framework. Prior to payout of an oil sands project, the royalty is payable on gross revenues of an oil sands project. Gross revenue royalty rates range between 1% and 9% depending on the market price of crude oil, determined using the average monthly price, expressed in Canadian dollars, for Western Texas Intermediate crude oil at Cushing, Oklahoma. Rates are 1% when the market price of crude oil is less than or equal to $55 per barrel and increase for every dollar of market price of crude oil increase to a maximum of 9% when crude oil is priced at $120 or higher. After payout, the royalty payable is the greater of the gross revenue royalty based on the gross revenue royalty rate of between 1% and 9% and the net revenue royalty based on the net revenue royalty rate. Net revenue royalty rates start at 25% and increase for every dollar of market price of crude oil increase above $55 up to 40% when crude oil is priced at $120 or higher.

The Government of Alberta has from time to time implemented drilling credits, incentives or transitional royalty programs to encourage crude oil and natural gas development and new drilling. In addition, the Government of Alberta has implemented certain initiatives intended to accelerate technological development and facilitate the development of unconventional resources, including as applied to coalbed methane wells, shale gas wells and horizontal crude oil and natural gas wells.

Freehold mineral taxes are levied for production from freehold mineral lands on an annual basis on calendar year production. Freehold mineral taxes are calculated using a tax formula that takes into consideration, among other things, the amount of production, the hours of production, the value of each unit of production, the tax rate and the percentages that the owners hold in the title. On average, in Alberta the tax levied is 4% of revenues reported from freehold mineral title properties. The freehold mineral taxes would be in addition to any royalty or other payment paid to the owner of such freehold mineral rights, which are established through private negotiation.

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract. Producers and working interest participants may also pay additional royalties to parties other than the mineral freehold owner where such royalties are negotiated through private transactions.

In addition to the royalties payable to the mineral owners (or to other royalty holders if applicable), producers of crude oil and natural gas from freehold lands in each of the western Canadian provinces are required to pay freehold mineral taxes or production taxes. Freehold mineral taxes or production taxes are taxes levied by a provincial government on crude oil and natural gas production from lands where the Crown does not hold the mineral rights. A description of the freehold mineral taxes payable in each of the western Canadian provinces is included in the above descriptions of the royalty regimes in such provinces.

Where oil and natural gas leases fall under the jurisdiction of the IOGC, the IOGC is responsible for issuing crude oil and natural gas agreements between Indigenous groups and producers and collecting and distributing royalty revenues. The exact terms and conditions of each crude oil and natural gas lease dictate the calculation of royalties owed, which may vary depending on the involvement of the specific Indigenous group. Ultimately, the relevant Indigenous group must approve the royalty rate for each lease.

Regulatory Authorities and Environmental Regulation

General

The Canadian crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas (“**GHG**”) emissions, including carbon dioxide equivalents (“**CO2e**”) may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law will prevail. The federal government has primary jurisdiction over federal works, undertakings and federally regulated industries such as railways, aviation and interprovincial transport including interprovincial pipelines.

On August 28, 2019, with the passing of Bill C-69, the CERA and the *Impact Assessment Act* ("**IAA**") came into force and the NEB Act and the *Canadian Environmental Assessment Act*, *2012* ("**CEAA 2012**") were repealed. In addition, the IA Agency replaced the Canadian Environmental Assessment Agency ("**CEA Agency**").

Bill C-69 introduced a number of important changes to the regulatory regime for federally regulated major projects and associated environmental assessments. Previously, the NEB administered its statutory jurisdiction as an integrated regulatory body. Now, the CERA separates the CER's administrative and adjudicative functions. A board of directors and a chief executive officer will manage strategic, administrative and policy considerations while adjudicative functions will fall into the purview of a group of independent commissioners. The CER has assumed the jurisdiction previously held by the NEB over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of these projects, culminating in their eventual abandonment.

Designated projects will require an impact assessment as part of their regulatory review. The impact assessment, conducted by a review panel, jointly appointed by the CER and the IA Agency, includes expanded criteria the review panel may consider when reviewing an application. The impact assessment also requires consideration of the project's potential adverse effects, the overall societal impact and the expanded public interest that a project may have. The impact assessment must look at the direct result of the project's construction and operation, including environmental, biophysical and socio-economic factors, including consideration of a gender-based analysis, climate change, and impacts to Indigenous rights. Designated projects include pipelines that require more than 75km of new right of way and pipelines located in national parks. Large scale in situ oil sands projects not regulated by provincial greenhouse gas emissions and certain refining, processing and storage facilities will also require an impact assessment.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process. Applications for nondesignated projects will follow a similar process as under the NEB Act. There is significant uncertainty surrounding the impact of Bill C-69 on oil and natural gas projects. There was significant opposition from industry and others in respect of Bill C-69, and notwithstanding its stated purpose, there is concern that the changes brought about by Bill C-69 will result in projects not being approved or increased delays in approvals. The Minister of Natural Resources has a mandate to implement the CER efficiently and effectively, but the CER's ability to expedite the project approval process has not yet been substantially tested.

On May 12, 2017, the federal government introduced Bill C-48 in Parliament. This legislation is aimed at providing coastal protection in northern British Columbia by prohibiting crude oil tankers carrying more than 12,500 metric tonnes of crude oil or persistent crude oil products from stopping, loading, or unloading crude oil in that area. Parliament passed Bill C-48 as the *Oil Tanker Moratorium Act* which received royal assent on June 21, 2019. The enactment of this statute may prevent pipelines from being built, and export terminals from being located on, the portion of the British Columbia coast subject to the moratorium (north of 50°53′00′′ north latitude and west of 126°38′36′′ west longitude) and, as a result, may negatively impact the ability of producers to access global markets.

Alberta

The AER is the single regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related pieces of legislation including the *Oil and Gas Conservation Act* (the "OGCA"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure. The objective behind a single regulator is an enhanced regulatory regime that is intended to be efficient, attractive to business and investors and effective in supporting public safety, environmental management and resource conservation while respecting the rights of landowners.

The Government of Alberta relies on regional planning to accomplish its responsible resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities by incorporating the management of all resources, including energy, minerals, land, air, water and biodiversity. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Parks, the Alberta Ministry of Energy, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy for surface land in Alberta sets out an approach to manage public and private land use and natural resource development in a manner that is consistent with the long-term economic, environmental and social goals of the province. It calls for the development of seven region-specific land-use plans in order to manage the combined impacts of existing and future land use within a specific region and the incorporation of a cumulative effects management approach into such plans. As a result, several regional plans have been implemented. These regional plans may affect further development and operations in such regions.

Liability Management Rating Program

The AER administers the licensee Liability Management Rating Program (the "**AB LMR Program**"). The AB LMR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. It consists of three distinct programs: the Licensee Liability Rating Program (the "**AB LLR Program**"), the Oilfield Waste Liability Program (the "**AB OWL Program**") and the Large Facility Liability Management Program (the "**AB LFP**"). If a licensee's deemed liabilities in the AB LLR Program, the AB OWL Program and/or the AB LFP exceed its deemed assets in those programs, the AB LMR Program requires the licensee to provide the AER with a security deposit and may restrict the licensee's ability to transfer licences. This ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's liability management rating ("**LMR**"). Where the AER determines that a security deposit is required, the failure to post any required amounts may result in the initiation of enforcement action by the AER.

The AER previously assessed the LMR of all licensees on a monthly basis and posted the individual ratings on the AER's public website. However, in December 2019 the AER ceased posting the detailed LMR report, stating that resource and budget limitations have impacted its ability to maintain and administer the AB LMR Program. Licensees can continue to access their individual LMR calculations through the AER's Digital Data Submission System. The AER is currently reviewing the AB LMR Program as it no longer considers the LMR value alone to be a good indicator of a company's financial health. It is unclear if, or when, any changes will be made to the current regulatory framework. Any changes to the AB LMR Program may affect the Company's ability to obtain or transfer licenses.

Complementing the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and AB OWL Program, including the Company, fund the Orphan Fund through a levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

On January 31, 2019, the Supreme Court of Canada overturned the lower courts' decisions in *Redwater Energy Corporation (Re)* ("**Redwater**"), holding that there is no operational conflict between the abandonment and reclamation provisions contained in the provincial OGCA, the liability management regime administered by the AER and the federal bankruptcy and insolvency regime. As a result, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a transfer when such a licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets of a bankrupt licensee that have reached the end of their productive lives and represent a liability and deal with the company's valuable assets for the benefit of the company's creditors, without first satisfying abandonment and reclamation obligations.

In response to the lower courts' decisions in Redwater, the AER issued several bulletins and interim rule changes to govern the AER's administration of its licensing and liability management programs. In Response to Redwater's trajectory through the Courts, the AER introduced amendments to its liability management framework. The AER amended its *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licensee eligibility to operate wells and facilities, to require the provision of extensive corporate governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has been subject to insolvency proceedings in the last five years. All transfers of well, facility and pipeline licences in the province are subject to AER approval. As a condition of transferring existing AER licences, approvals and permits, all transfers are now assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have an LMR of 2.0 or higher immediately following the transfer, or to otherwise prove to the satisfaction of the AER that it can meet its abandonment and reclamation obligations. The AER may make further rule changes at any time. The Supreme Court of Canada's Redwater decision alleviates some of the concerns that the AER's rule changes were intended to address, however the AER has indicated it is in the process of reviewing the current framework.

The AER has also implemented the Inactive Well Compliance Program (the "**IWCP**") to address the growing inventory of inactive wells in Alberta and to increase the AER's surveillance and compliance efforts under *Directive 013: Suspension Requirements for Wells* ("**Directive 013**"). The IWCP applies to all inactive wells that are noncompliant with Directive 013 as of April 1, 2015. The objective is to bring all inactive noncompliant wells under the IWCP into compliance with the requirements of Directive 013 within five years. As of April 1, 2015, each licensee is required to bring 20% of its inactive wells into compliance every year, either by reactivating or suspending the wells in accordance with Directive 013 or by abandoning them in accordance with *Directive 020: Well Abandonment*. The list of current wells subject to the IWCP is available on the AER's Digital Data Submission System. The AER has announced that from April 1, 2015 to April 1, 2016, the number of noncompliant wells subject to the IWCP fell from 25,792 to 17,470, with 76% of licensees operating in the province having met their annual quota. From April 1, 2016 to April 1, 2017, this number fell from 17,470 to 12,375 noncompliant wells, with 81% of licensees operating in the province having met their annual quota. The IWCP will complete its fifth year on March 31, 2020 but the AER has not released subsequent annual reports on compliance levels since 2017.

As part of its strategy to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure, the AER announced a voluntary area-based closure ("**ABC**") program in 2018. The ABC program is designed to reduce the cost of abandonment and reclamation operations though industry collaboration and economies of scale. Participants seeking the program incentives must commit to an inactive liability reduction target to be met through closure work of inactive assets.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the future of the crude oil and natural gas industry in Canada. The impacts of federal or provincial climate change and environmental laws and regulations are uncertain. It is currently not possible to predict the extent of future requirements. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on the Company's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy experiments with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. As of December 23, 2019, 187 of the 197 parties to the convention have ratified the Paris Agreement. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference in Glasgow in 2020. However, the European Union reached an agreement about "The European Green New Deal" that aims to lower emissions to zero by 2050.

Following the Paris Agreement and its ratification in Canada, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030. Further, on December 9, 2016, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change (the "**Framework**"). The Framework provided for a carbon-pricing strategy, with a carbon tax starting at $10/tonne in 2018, increasing annually until it reaches $50/tonne in 2022. This system applies in provinces and territories that request it and in those that do not have a carbon pricing system in place that meets the federal standards. On June 21, 2018, the federal government enacted the *Greenhouse Gas Pollution Pricing Act* (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an emissions trading system for large industry and a regulatory fuel charge imposing an initial price of $20/tonne of GHG emissions. Under current federal plans, this price will escalate by $10 per year until it reaches a price of $50/tonne in 2022. Starting April 1, 2020, the minimum price permissible under the GGPPA is $30/tonne of GHG emissions.

Six provinces and territories have introduced carbon-pricing systems that meet federal requirements: British Columbia, Quebec, Prince Edward Island, Nova Scotia, Newfoundland and Labrador, and the Northwest Territories. The federal fuel charge regime took effect in Saskatchewan, Manitoba, Ontario, and New Brunswick on April 1, 2019 and in the Yukon and Nunavut on July 1, 2019. The federal carbon-pricing regime took effect in Alberta on January 1, 2020. Alberta, Saskatchewan, and Ontario challenged the constitutionality of the federal government's pricing regime. The reference in Alberta remains before the Alberta Court of Appeal, but the Saskatchewan and Ontario references have advanced in parallel where the appeal Courts ruled in favour of the constitutionality of the federal carbon tax. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada. The Court is set to hear the appeals in March of 2020. Ontario and Saskatchewan will cross-intervene in the appeals, along with the Attorneys General of Quebec, New Brunswick, Manitoba, British Columbia, and Alberta, who will intervene in both proceedings.

On April 26, 2018, the federal government passed the *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the crude oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and intentional venting of methane, as well as ensuring that crude oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. These facilities would need to capture the gas and either re-use it, re-inject it, send it to a sales pipeline, or route it to a flare. In addition, in provinces other than Alberta and British Columbia (which already regulate such activities), well completions by hydraulic fracturing would be required to conserve or destroy gas instead of venting. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

In October 2018, the federal government announced a pricing scheme as an alternative for large electricity generators so as to incentivize a reduction in emissions intensity, rather than encouraging a reduction in generation capacity.

Alberta

On November 22, 2015, the Government of Alberta introduced a Climate Leadership Plan (the "**CLP**"). Under this strategy, the *Climate Leadership Act* (the "**CLA**") came into force on January 1, 2017 and established a fuel charge intended to first outstrip and subsequently keep pace with the federal price. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, excluding some attributable to upgraders, the electric energy portion of cogeneration and other prescribed emissions.

In June 2019, the Government of Alberta pivoted in its implementation of the CLP and repealed the CLA. The Carbon Competitiveness Incentives Regime ("**CCIR**") remained in place. As a result, the federally imposed fuel charge took effect in Alberta on January 1, 2020, at a rate of $20/tonne. In accordance with the GGPPA, this will increase to $30/tonne on April 1, 2020. However, on December 4, 2019, the federal government approved Alberta's proposed *Technology Innovation and Emissions Reduction* ("**TIER**") regulation intended to replace the CCIR, so the regulation of emissions from heavy industry remains subject to provincial regulation, while the federal fuel charge still applies. The TIER regulation came into effect on January 1, 2020.

The TIER regulation operates differently than the former facility-based CCIR, and instead applies industry-wide to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The 2020 target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark (which is, generally, its average emissions intensity during the period from 2013 to 2015), with a further 1% reduction for each subsequent year. The facility-specific benchmark does not apply to all facilities. Certain facilities, such as those in the electricity sector, are compared against the good-as-best-gas standard, which measures against the emissions produced by the cleanest natural gas-fired generation system. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. As with the former CCIR, the TIER regulation targets emissions intensity rather than total emissions. Under the TIER regulation, facilities in high-emitting sectors can opt-in to the program despite the fact that they do not meet the 100,000 tonne threshold. A facility can opt-in to TIER regulation if it competes directly against another TIER-regulated facility or if it has annual CO2e emissions that exceed 10,000 tonnes per year and belongs to an emissions-intensive or trade exposed sector with international competition. In addition, the owner of two or more "conventional oil and gas facilities" may apply to have those facilities regulated under the TIER regulation. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports and facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

The Government of Alberta previously signaled its intention through the CLP to implement regulations that would lower annual methane emissions by 45% by 2025. Pursuant to this goal, the Government of Alberta enacted the *Methane Emission Reduction Regulation* (the "**Alberta Methane Regulations**") on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. Together, these new Directives represent Alberta's first step toward achieving its 2025 goal, as outlined in the Alberta Methane Regulations; however, the Government of Alberta and the federal government have not yet reached an equivalency agreement with respect to the Alberta Methane Regulations and the Federal Methane Regulations.

Alberta was also the first jurisdiction in North America to direct dedicated funding to implement carbon capture and storage technology across industrial sectors. Alberta has committed $1.24 billion through 2025 to fund two commercial-scale carbon capture and storage projects. Both projects will help reduce the CO2 emissions from the oil sands and fertilizer sectors, and reduce GHG emissions by 2.76 million megatonnes per year. On December 2, 2010, the Government of Alberta passed the *Carbon Capture and Storage Statutes Amendment Act, 2010*. It deemed the pore space underlying all land in Alberta to be, and to have always been the property of the Crown and provided for the assumption of long-term liability for carbon sequestration projects by the Crown, subject to the satisfaction of certain conditions.

RISK FACTORS

An investment in our Common Shares is subject to various risks including risks inherent in our industry. If any of the following risks or other risks materialize, our business, prospects, financial condition, results of operations and cash flows could be materially and adversely impacted. The trading price of the Common Shares could decline and investors could lose all or part of their investment in the Common Shares. There is no assurance that risk management steps taken by Athabasca will avoid future loss due to the occurrence of the risk factors described below or other unforeseen risks. Investors should carefully consider the risks described below and the other information contained in this Annual Information Form before making a decision to buy Common Shares.

The information set forth below contains forward-looking statements. See "*Forward-Looking Statements*".

Risks Relating to Our Industry and Operations

Weakness in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, slowing growth in China and in emerging economies, market volatility, weakening global relationships, isolationist trade policies, increased U.S. shale production and sovereign debt levels in various countries, have caused significant weakness and volatility in commodity prices. See "*Risk Factors – Political Uncertainty"*. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by changes in government and the uncertainty surrounding regulatory, tax and royalty changes that have been announced or may be or have been implemented by the federal and provincial governments. See various "*Risk Factors"*. In addition, the inability to get the necessary approvals to build pipelines and other facilities to provide better access to markets for the oil and gas industry in western Canada has led to additional downward price pressure on oil and gas produced in western Canada and reduced confidence in the oil and gas industry in western Canada. See "*Industry Conditions – Transportation Constraints and Market Access"*.

Lower commodity prices may also affect the volume and value of our reserves especially as certain reserves become uneconomic. In addition, lower commodity prices have restricted, and may continue to restrict, our cash flow resulting in a reduced capital expenditure budget. As a result, Athabasca may not be able to replace its production with additional reserves and both its production and reserves could be reduced on a year over year basis. Any decrease in value of our reserves may reduce the amounts available under the Amended Credit Facility. Given the current market conditions and the lack of confidence in the Canadian oil and gas industry, we may have difficulty raising additional funds or if we are able to do so, it may be on unfavourable terms.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, our existing reserves, and the production from them, will decline over time as we produce from such reserves. A future increase in our reserves will depend on both our ability to explore and develop our existing properties and our ability to select and acquire suitable producing properties or prospects. There is no assurance that we will be able to continue to find satisfactory properties to acquire or participate in. Moreover, Athabasca management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife.

Oil and natural gas production operations, including SAGD operations, are also subject to geological and seismic risks, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Future crude oil and gas exploration may involve unprofitable efforts, from dry wells or wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completing (including hydraulic fracturing) and operating costs. In addition, drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents and shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash flow levels to varying degrees.

Our assets are in relatively early stages exploration or development. There is a risk that the proposed commercial development of our assets will not achieve the expected production levels on the timing anticipated or at all and that the capital costs of such projects will not be within the applicable estimates.

Properties that we decide to drill that do not yield oil, natural gas or NGLs in commercial quantities will adversely affect our results of operations and financial condition. There is no way to conclusively predict in advance of drilling and testing whether any particular well will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

Recovering bitumen from oil sands and upgrading the recovered bitumen into a diluent-bitumen blend product or other products involves particular risks and uncertainties. Our projects will be susceptible to loss of production, slowdowns, or restrictions on our ability to produce higher value products due to the interdependence of the component systems.

Prices, Markets and Marketing

Numerous factors beyond our control do, and will continue to, affect the marketability and price of oil and natural gas. Our ability to market our oil and natural gas may depend upon our ability to acquire space on pipelines that deliver our production to commercial markets. Deliverability uncertainties related to the distance our reserves are from pipelines, railway lines, processing and storage facilities, operational problems affecting pipelines, railway lines and facilities, railway blockades as well as government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect us.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic conditions in the United States, Canada, Europe, China and emerging markets, the actions of OPEC, governmental regulation, political instability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. Oil prices are expected to remain volatile and may decline in the near future as a result of global excess supply due to the increased growth of shale oil production in the United States, the decline in global demand for exported crude oil commodities, potential economic disruption that may result from the spread of COVID-19 (coronavirus), and OPEC's decisions pertaining to the oil production of OPEC member countries, among other factors. A material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of our reserves. We might also elect not to produce from certain wells at lower prices.

All these factors could result in a material decrease in our expected net production revenue and a reduction in our oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on our carrying value of our reserves, borrowing capacity including available limits under our Amended Credit Facility, revenues, profitability and cash flows from operations and may have a material adverse effect on our business, financial condition, results of operations and prospects.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties. Volatile oil and natural gas prices make it difficult to estimate the value of producing properties for acquisitions and often cause disruption in the market for oil and natural gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development projects.

Market Conditions

The trading price of securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, a number of factors, including concerns about effects of the use of fossil fuels on climate change have affected investor sentiment and some investors have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our reputation, operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which Common Shares will trade cannot be accurately predicted.

Climate Change and Carbon Pricing Risk

Our exploration and production facilities and other operations and activities, and the products we market, result in the emission of GHGs which makes us subject to GHG emissions legislation and regulations at the provincial and federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the United Nations Framework Convention on Climate Change and a party to the Paris Agreement, the Government of Canada committed to a 30% reduction in GHG emissions below 2005 levels by 2030.

One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the implementation of a nation-wide price on carbon emissions. Provincially, the Government of Alberta has implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change and public discussion that climate change may be associated with extreme weather conditions have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in our profitability and a reduction in the value of our assets or asset write-offs. See "*Industry Conditions – Climate Change Regulation*".

Regulatory

The oil and gas industry in Canada, including the oil sands industry, operates under federal and provincial statutes and regulations governing such matters as land tenure, prices, royalties, production rates, environmental protection controls, the export of crude oil, natural gas and other products, as well as other matters. The industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands, petroleum, natural gas or other interests, the imposition of specific drilling obligations, control over the development and abandonment of oil and natural gas properties (including restrictions on production) and possible expropriation or cancellation of lease and permit rights. The regulatory scheme as it relates to oil sands, and the recovery and marketing of bitumen or bitumen by-products from oil sands, is somewhat different and more burdensome from that related to conventional oil and gas in general.

Government regulations may be changed from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing statutes or regulations, the implementation of new statutes or regulations or the modification of existing statutes or regulations affecting the crude oil and natural gas industry could impact the markets for crude oil and natural gas, delay or stop the development of our projects, delay or increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. For instance, on December 2, 2018, the Government of Alberta announced a temporary curtailment of crude oil and bitumen production, which came into force in Alberta on January 1, 2019. See *"Industry Conditions – Curtailments"*. The Company now receives a monthly curtailment order which sets out the combined amount of crude oil and crude bitumen that the Company can produce from its Thermal Oil Division.

In order to conduct oil and gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. The requirements imposed by any such authority may be costly and time-consuming and may delay commencement or continuation of exploration or our production operations. In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) which could limit our ability to access external sources of capital and could cause a decrease in the valuation of Canadian companies.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail, some of which we do not own. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of firm pipeline capacity, production limits and limits on availability of capacity in gathering and processing facilities continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. See "*Industry Conditions – Transportation Constraints and Market Access*" and "*Industry Conditions – Curtailment*". In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability of oil and natural gas companies to export oil and natural gas and could result in our inability to realize the full economic potential of our products or in a reduction of the price offered for our production. Unexpected shut downs or curtailment of capacity of pipelines for maintenance or integrity work or because of actions taken by regulators could also affect our production, operations and financial results. As a result, producers have considered rail lines as an alternative means of transportation. Announcements and actions taken by the federal government and the provincial governments of British Columbia, Alberta and Quebec relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. On August 28, 2019, with the passing of Bill C-69, the *Canadian Energy Regulator Act* and the *Impact Assessment Act* came into force and the *National Energy Board Act* and the *Canadian Environmental Assessment Act, 2012* were repealed. In addition, the Impact Assessment Agency of Canada replaced the Canadian Environmental Assessment Agency. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*". The impact of the new federal regulatory scheme on proponents, and the timing for receipt of approvals, of major projects is unclear.

A portion of the Company's production may, from time to time, be processed through facilities owned by third parties and over which the Company does not have control. From time to time, these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuation or decrease of operations could have a material adverse effect on the Company's ability to process its production and deliver the same to market . Midstream and pipeline companies may take actions to maximize their return on investment, which may in turn adversely affect producers and shippers, especially when combined with a regulatory framework that may not always align with the interests of particular shippers.

Statutes and Regulations Regarding the Environment

Our operations are, and will continue to be, affected in varying degrees by federal and provincial statutes and regulations regarding the protection of the environment. Should there be changes to existing statutes or regulations, our competitive position within the oil sands and petroleum and natural gas industries may be adversely affected, and many industry players have greater resources than us.

Future environmental approvals, laws or regulations may adversely impact our ability to develop and operate our oil sands or light oil projects or increase or maintain production, may increase unit costs of production, or may prevent us from realizing other business opportunities from our exploration leases and permits. Equipment from suppliers which can meet future emission standards may not be available on an economic or timely basis and other methods of reducing emissions to required levels in the future may significantly increase operating costs or reduce output. There is a risk that the federal and/or provincial governments could pass legislation that would tax such emissions or require, directly or indirectly, reductions in such emissions produced by energy industry participants, which we may be unable to mitigate.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain oil and gas industry operations and requirements to report, investigate and remediate such spill, release or emission. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection, occupational health and safety and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines, penalties and other liabilities, some of which may be material, or the revocation or denial of permits necessary to our business. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Under certain circumstances, we can have liability for contamination at our facilities even if it arises from third parties or from conduct that was legal at the time it occurred. No assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Political Uncertainty

Political events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely, peaceful developments, arising outside of Canada have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and could have a material adverse effect on Athabasca's results of operations, financial condition and prospects. For instance, in the last several years, the United States, Europe and Latin America have experienced significant political events that have cast uncertainty on global financial and economic markets. See "*Industry Conditions*".

In addition to the risks outlined herein related to geopolitical developments, our oil and natural gas properties, wells and facilities could be subject to public opposition, terrorist attack, blockades or physical sabotage. If any of our properties, wells or facilities are the subject of opposition, terrorist attack, or sabotage it may have a material adverse effect on our business, financial condition, results of operations and prospects. Furthermore, any interruption in the services provided by infrastructure on which Athabasca relies as a result of a terrorist attack would have a material adverse effect. We may not carry insurance to protect against risks arising from terrorism.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. Alberta elected a new government in 2019 that is supportive of the Trans Mountain Pipeline expansion project while a minority government in British Columbia remains opposed to the project and has attempted to regulate the transport of heavy oil products into and through British Columbia. Though the Supreme Court of Canada unanimously rejected the government of British Columbia's proposed regulation of the transport of heavy oil products into and through British Columbia, disputes remain between provincial and federal governments. Continued uncertainty and delays have led to decreased investor confidence, increased capital costs and operational delays for producers and service providers operating in the jurisdiction

The federal Government was re-elected in 2019, but in a minority position. The ability of the minority federal government to pass legislation will be subject to whether it is able to come to agreement with, and garner the support of, the other elected parties, most of whom are opposed to the development of the oil and natural gas industry. The minority federal government will also be required to rely on the support of the other elected parties to remain in power, which provides less stability and may lead to an earlier subsequent federal election. Political instability, at both the federal and provincial level, continues to create regulatory uncertainty, the effects of which become apparent on an ongoing basis, particularly with respect to carbon pricing regimes, curtailment of crude oil production and transportation and export capacity, and may affect the business of participants in the oil and natural gas industry, including ours. See "*Industry Conditions".*

Anticipated Benefits of Acquisitions and Dispositions

We consider joint ventures and acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with our business and operations. The integration of acquired businesses may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, certain assets may be periodically disposed of so we can focus our efforts and resources more efficiently. Depending on the state of the market for such assets, certain of our assets, if disposed of, may realize less than their carrying value on our financial statements.

Ability to Finance Capital Requirements

Substantial capital expenditures will be required to fund our exploration and development activities. Our 2019 capital and operating budgets were funded with cash flow from operations, existing cash and cash equivalents, and the obligation of Murphy to fund the Kaybob Carry Commitment. In 2020 and beyond, depending on our level of capital spend and the commodity price environment, we may require additional funding which could include debt, equity, joint ventures, asset sales or other financing. The availability of any additional future funding will depend on, among other things, the current commodity price environment, operating performance, our credit rating at the time and the current state of the equity and debt capital markets. A reduction in the current rating on the Company's debt by one or more of its rating agencies or a negative change in the Company's ratings outlook could adversely affect the Company's cost of financing and its access to sources of liquidity and capital. There can be no assurance that the cash that may be generated from our operations and/or the other sources of financing, including the ability to raise additional capital through debt financing or refinancing, will be available or sufficient to meet our requirements, or if external sources of funding are available, that they will be available on terms that are acceptable to us. Additionally, asset divestments are subject to certain limitations in terms of how we are permitted to allocate the proceeds pursuant to the terms of the Amended Credit Facility and the 2022 Notes.

State of the Capital Markets

A number of factors, including the concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns and government delays concerning market access, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from our Board, management and employees. Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in us or not investing in us at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, in us, may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares.

Abandonment and Reclamation Costs

We will need to comply with the terms and conditions of environmental and regulatory approvals and all laws and regulations regarding the abandonment of our projects and reclamation of project lands at the end of their economic life, which will result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of our approvals and such legislation and/or regulations may result in the imposition of fines and penalties.

It is not possible at this time to estimate abandonment and reclamation costs reliably since they will, in part, depend on future regulatory requirements. In addition, in the future, we may determine it prudent or be required by applicable laws, regulations or regulatory approvals to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs. If Athabasca establishes a reclamation fund, its liquidity and cash flow may be adversely affected.

Changing Demand for Oil and Natural Gas Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and energy generation devices could reduce the demand for oil, natural gas and other liquid hydrocarbons. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash flows.

Royalty Regimes

There can be no assurance that the federal government and the provincial governments of the western provinces will not adopt new royalty regimes or modify the existing royalty regimes which may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economic. For a discussion of current applicable royalty regimes please see "*Industry Conditions - Royalties and Incentives*".

Foreign Exchange Rates and Interest Rates

World oil and gas prices are quoted in United States dollars. The Canadian/U.S. dollar exchange rate, which fluctuates over time, consequently affects the price received by the Canadian producers of oil and natural gas. Recently, the Canadian dollar has decreased materially in value against the U.S. dollar. Material increases in the value of the Canadian dollar will negatively affect our production revenues.

We have U.S. denominated debt and we may incur further additional U.S. dollar denominated debt in the future which creates exposure for us to fluctuations in currency exchange rates. In addition, we may in the future incur indebtedness at variable rates of interest that expose us to additional interest rate risk. If interest rates increase, our debt service obligations on such variable rate indebtedness would increase even though the amount borrowed remains the same, and our net income and cash flows would decrease. This could result in a reduced amount available to fund our exploration and development activities and could negatively impact the market price of the Common Shares. To the extent that we engage in risk management activities related to foreign exchange rates or interest rates, there is a credit risk associated with counterparties with whom we may contract.

Reserves

There are numerous uncertainties inherent in estimating the quantities of reserves and resources attributable to our assets and the future cash flows attributed to such reserves and resources, including many factors beyond our control, and no assurance can be given that the indicated level of reserves and resources and future net revenues will be realized.

In general, estimates of recoverable reserves and resources are based upon a number of factors and assumptions made as of the date on which the reserves and resource estimates were determined, such as geological and engineering estimates, historical production, production rates, well spacing, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, and the assumed effects of regulation by governmental agencies, estimates of future commodity prices and operating costs, all of which may vary considerably from actual results. All such estimates are, to some degree, uncertain and classifications of reserves and resources are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable bitumen, crude oil and natural gas and the classification of such reserves and resources based on risk of recovery prepared by different engineers or by the same engineers at different times may vary substantially.

In accordance with applicable securities laws, McDaniel used forecast prices and costs in estimating our reserves and future net cash flows as of December 31, 2019. Actual future net cash flows will also be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Our ability to replenish our reserves is important to our long-term viability. Depleted reserves must be replaced by further development of existing sites or by locating new sites in order to maintain production levels over the long term. Resource exploration and development are highly speculative in nature. Our exploration projects involve many risks, require substantial expenditures and may not result in the discovery of sufficient additional deposits that can be extracted profitably. Once a site with deposits is discovered, it may take several years from the initial phases of drilling until production is possible, during which time the economic feasibility of production may change. Substantial expenditures are required to establish recoverable proven and probable reserves and to construct extraction and processing facilities. As a result, there is no assurance that current or future exploration programs will be successful and there is a risk that depletion of reserves will not be offset by discoveries or acquisitions.

Hedging

The nature of our operations will result in exposure to fluctuations in commodity prices. We use financial instruments and may use physical delivery contracts to hedge our exposure to these risks. In addition, we have previously and may in future enter into hedging arrangements to act as a risk control mechanism with respect to foreign denominated debt. If product prices increase above those levels specified in any future hedging agreements, we could lose the cost of floors or a fixed price could limit us from receiving the full benefit of commodity price increases. If we enter into hedging arrangements, we may suffer financial loss if we are unable to commence operations on schedule, production falls short of the hedged volumes or prices fall significantly lower than projected, there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement, the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements, a sudden unexpected event materially impacts oil and natural gas prices, or if we are unable to produce sufficient quantities of bitumen, crude oil or natural gas to fulfill our obligations. If currency exchange rates result in a stronger-performing Canadian dollar relative to previously incurred foreign denominated debt, this may result in us incurring financial loss as a result of the financial hedging arrangements we have in place.

Operational Dependence

Other companies operate some of the assets in which we have an interest. We have limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect our financial performance. Our return on assets operated by others depends upon a number of factors that may be outside of our control, including, but not limited to, the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices. For instance, we will be dependent upon Murphy as operator of the Great Kaybob area.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, we may be required to satisfy such obligations and to seek recourse from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, Athabasca potentially becoming subject to additional liabilities relating to such assets and Athabasca having difficulty collecting revenue due from such operators. Any of these factors could materially adversely affect our financial and operational results.

Operating Costs

The operating costs of the projects undertaken by us will be significant components of the cost of production of the products produced by such projects. Those operating costs may vary considerably during the operating period. The principal factors which could affect operating costs include, without limitation: the amount and cost of labour to operate the projects; the cost of chemicals; the actual SOR required to operate our oil sands projects; the cost of natural gas, diluent and electricity; the cost of complying with regulatory approvals; the maintenance cost of the facilities; the cost to process product; the cost to transport sales products and the cost to dispose of certain by-products; and the cost of insurance and taxes. Unexpected increases in operating costs may result in decreased earnings, which may in turn have a material adverse effect on our results of operations and financial condition.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. Additionally, there is a risk that our future projects may have delays, interruption of operations or increased costs. Our ability to execute projects, and the performance of such projects, depends upon numerous factors beyond our control, including:

- an inability to obtain adequate financing, or financing on terms satisfactory to us;
- shortages of, or delays in, obtaining qualified labour, equipment, materials or services;
- changes in the scope of the project or increases in the amount or cost of materials or labour;
- contractor or operator errors in design or construction and non-performance by, or financial failure of, third party contractors;
- breakdown or failure of equipment or processes including facility performance falling below expected levels of output or efficiency;
- reservoir performance;
- unforeseen site surface or subsurface conditions;
- the availability of, and the ability to acquire, water supplies needed for drilling, or our ability to dispose of water used or removed from strata at reasonable costs and within applicable environmental regulations;
- disruption in the supply of energy;
- the availability of processing, transportation and storage capacity;
- the effects of inclement weather;
- unexpected cost increases;
- accidental events;
- delays in obtaining required regulatory approvals;
- currency fluctuations;
- regulatory changes; and
- the regulation of the oil and natural gas industry by various levels of government and agencies.

Because of these factors, we could be unable to execute projects on time, on budget or at all or the projects may not perform to our expectations or as required by regulatory approvals. Any delays may increase the costs of those projects, which could result in the need for additional capital, and there can be no assurance that such capital will be available on acceptable terms or at all.

Financial Assurances

We have contracts for pipeline transportation in place with third parties which contain certain financial assurance covenants. Depending upon our capitalization, liquidity position and state of operational performance at certain times, we may not be in a position to comply with the financial assurance covenants contained within these agreements, which may require us to provide security to the third parties we have contracted with including, but not limited to, letters of credit.

Diluent Supply

Bitumen has a high specific gravity or weight and high viscosity or resistance to flow. Diluent is required to facilitate the processing and transportation of heavy oil and bitumen. A shortage of diluent may cause our costs to increase thereby increasing the cost to transport heavy oil and bitumen to market and increasing our overall operating costs resulting in decreased net revenues and negatively impacting our overall profitability.

Third Party Credit Risk

We may be exposed to third party credit risk through our contractual arrangements with our current or future joint venture partners, marketers of our petroleum and natural gas production and other parties. In addition, we may be exposed to third party credit risk from operators of properties in which we have a working or royalty interest. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of partners may affect a partner's willingness to participate in our ongoing capital program, potentially delaying the program and the results of such program until we find a suitable alternative partner. To the extent that any of such third parties go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in us being unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Aboriginal Claims

Aboriginal peoples have claimed aboriginal title and rights to portions of western Canada. We are not aware that any claims have been in respect of our properties or assets. Claims by aboriginal peoples or groups could, among other things, delay or prevent the exploration or development of our properties, which in turn could have a material adverse effect on our business, financial condition, results of operations and prospects.

Reliance on Key Personnel and Operators

Our success depends in large measure on certain key personnel. The loss of or changes in the services provided by such key personnel may have a material adverse effect on its business, financial condition, results of operations and prospects. We do not have any key person insurance in effect. The contributions of the existing management team to our immediate and near-term operations are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of our management.

Income Tax

Income tax provisions, including current and future income tax assets and liabilities in our financial statements, and income tax filing positions require estimates and interpretations of federal and provincial income tax rules and regulations, and judgments as to their interpretation and application to our specific situation. In addition, there can be no assurance that the Canada Revenue Agency or a provincial or other tax agency will agree with our tax filing positions or will not change its administrative practices to our detriment. Our business and operations are complex and we have executed a number of significant financings, acquisitions, dispositions, reorganizations, joint ventures and business combinations. The computation of income taxes payable as a result of these transactions involves many complex factors as well as our interpretation of and compliance with relevant tax legislation and regulations. While we believe that our tax filing positions are supportable under applicable law, a number of our tax filing positions are or may be the subject of review by taxation authorities. Income tax laws relating to the oil and gas industry may in the future be changed or interpreted in a manner that adversely affects us. Therefore, it is possible that additional taxes could be payable by us and the ultimate value of our income tax assets and liabilities could change in the future and that such additional taxes and changes to such amounts could be materially adverse to us.

Cybersecurity

Athabasca’s operations may be negatively impacted by a cybersecurity incident. We use forms of information technology in our operations and such use creates cybersecurity threats including the possibility of potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of our information technology systems by third parties or insiders. Unauthorized access to these systems by employees or third parties could lead to corruption or exposure of confidential, fiduciary or proprietary information, interruption to communications or operations or disruption to our business activities or our competitive position. Further, disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as on our reputation. Although we have taken various steps to protect ourselves against such risks, the efforts may not always be successful. In the event of a cybersecurity incident, our operations could be disrupted resulting in a material adverse effect on our business, financial condition and results of operations.

Advanced Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before us. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. In such case, our business, financial condition and results of operations could be affected adversely and materially. If we are unable to utilize the most advanced commercially available technology, our business, financial condition and results of operations could also be adversely affected in a material way.

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements or amendments to or stricter interpretation or enforcement of existing laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase our costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Due to seismic activity reported in the Fox Creek area of Alberta, the AER announced in February 2015, seismic monitoring and reporting requirements for hydraulic fracturing operators in the Duvernay zone in the Fox Creek area. These requirements include, among others, an assessment of the potential for seismicity prior to conducting operations, the implementation of a response plan to address potential seismic events, and the suspension of operations if a seismic event above a particular threshold occurs. These requirements will remain in effect as long as the AER deems them necessary. Further, the AER continues to monitor seismic activity around the province and may extend these requirements to other areas of the province if necessary.

Liability Management

Alberta has developed a liability management program designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder is unable to satisfy its obligation. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes to the required ratio of our deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to our compliance requirement. In addition, the liability management system may prevent or interfere with our ability to acquire or dispose of assets as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The impact and consequences of the Supreme Court of Canada in the Redwater case on the AER’s rules and policies, lending practices in the crude oil and natural gas sector and on the nature and determination of secured lenders to take enforcement proceedings will evolve as the decision is evaluated. See “*Industry Conditions - Regulatory Authorities and Environmental Regulation - Liability Management Rating Program*”.

Seasonality and Weather Conditions

The level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of our production if not otherwise tied-in. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Global climate change could impact the timing and length of the winter and corresponding spring thaws, which could adversely affect our business and operating results. Furthermore, extreme climate conditions that could result in natural disasters such as flooding or fires, may result in increased expenditures or delays or cancellation of some of our operations.

Additionally, climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. Long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns discussed above. In addition, long-term shifts in weather patterns such as water scarcity, increased frequency of storm and fire and prolonged heat waves may, among other things, require us to incur greater expenditures to address such changes to our operations, which may have a material adverse effect on our results of operations and increased costs to obtain insurance.

Unexpected Events

Operating levels within the oil and gas extraction industry are subject to unexpected conditions and events that are beyond the industry's control. Those events could cause industry members or their suppliers to curtail production or shut down a portion or all of their operations, which could reduce the demand for our products, and could affect adversely our sales, margins and profitability.

Interruptions in production capabilities inevitably will increase our production costs and potentially reduce our profitability. We do not have meaningful excess capacity for current production needs, and we are not able to quickly increase production at one site to offset an interruption in production at another site.

A portion of our production costs are fixed regardless of current operating levels. As noted, our operating levels are subject to conditions beyond our control that can delay deliveries or increase the cost of operation at particular sites for varying lengths of time. These include weather conditions (for example, extreme winter weather, tornadoes, floods, and the lack of availability of process water due to drought) and natural and man-made disasters, wildfires like the Fort McMurray wildfire in 2016, unanticipated geological conditions, including variations in the amount and type of rock and soil overlying the oil or natural gas deposits, variations in rock and other natural materials and variations in geologic conditions.

The processes that take place in our facilities and those facilities owned by third parties through which our production is transported and processed, depend on critical pieces of equipment. This equipment may, on occasion, be out of service because of unanticipated failures. Remediation of any interruption in production capability may require us to make large capital expenditures that could have a negative effect on our profitability and cash flows. Our business interruption insurance would not cover all or any of the lost revenues associated with equipment failures. Longer-term business disruptions could result in a loss of customers, which adversely could affect our future sales levels and, therefore, our profitability.

Internal Controls

Effective internal controls are necessary for us to provide reliable financial reports and to help prevent fraud. Although we undertake a number of procedures in order to help ensure the reliability of our financial reports, including those imposed on us under Canadian securities laws, we cannot be certain that such measures will ensure that we will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm our results of operations or cause us to fail to meet our reporting obligations. If we or our independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in our consolidated financial statements and harm the trading price of the Common Shares.

Insurance

Our involvement in the exploration for and development of oil, natural gas and bitumen properties may result in us becoming subject to liability for pollution, blow outs, leaks of sour gas, property damage, personal injury or other hazards. Although we maintain insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. Our property, business interruption and liability insurance is subject to deductibles, limits and exclusions, and may not provide sufficient coverage for these and other insurable risks. In addition, certain risks are not, in all circumstances, insurable or, in certain circumstances, we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to us. The occurrence of a significant event that we are not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on our business, financial condition, results of operations and prospects.

Litigation

In the normal course of our operations, we are or we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land rights, environmental issues, including claims relating to contamination or natural resource damages, and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail in any such legal proceeding, the proceedings could be costly and time-consuming and would divert the attention of management and key personnel from our business operations, which could adversely affect our financial condition.

Natural Gas Overlying Bitumen Resources

Some of our oil sands leases contain producing and shut-in natural gas wells owned by third parties that may penetrate, or otherwise result in the applicable petroleum and natural gas zones coming into communication with, our bitumen resources. In October 2009, the ERCB ordered the interim shut-in of 297 intervals associated with 158 gas wells largely in the Dover West area to mitigate potential future risk to bitumen recovery in the area. On December 15, 2011, pursuant to Order 11-002, the ERCB shut-in these, as well as other wells. There are also natural gas zones in several of our asset areas that do not currently contain producing or shut-in natural gas wells. There is a risk that if the production of natural gas from these zones penetrates or otherwise comes into communication with our bitumen resources, there may be a loss of steam or steam chamber pressure during the SAGD bitumen extraction process, which could adversely affect our ability to recover bitumen using SAGD technology. No assurance can be provided that the production or potential production of natural gas overlying bitumen resources on our oil sands leases will not pose a risk to our ability to recover the bitumen resources on these properties using SAGD technology, and such risk could have a material adverse effect on our business, financial condition, liquidity and results of operations.

Competition

The petroleum industry is competitive in all of its phases. We compete with numerous other entities in the exploration, development, production and marketing of oil and natural gas. Our competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than us. Some of these companies not only explore for, develop and produce oil and natural gas, but also carry on refining operations and market oil and natural gas on an international basis. As a result of these complementary activities, some of these competitors may have greater and more diverse competitive resources to draw on than us. Our ability to increase our reserves in the future will depend not only on our ability to explore and develop our present properties, but also on our ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price, process, and reliability of delivery and storage.

Chain of Title and Expiration of Licenses and Leases

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise. Our actual interest in properties may, accordingly, vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes which affect our title to the oil and natural gas properties we control that could impair our activities on them and result in a reduction of the revenue received by us. Moreover, our licenses and leases may terminate or expire and there can be no assurance that any of the obligations required to maintain each license or lease will be met.

Breaches of Confidentiality

While discussing potential business relationships or other transactions with third parties, we may disclose confidential information relating to our business, operations or affairs. Although confidentiality agreements are generally signed by third parties prior to the disclosure of confidential information, a breach could put us at competitive risk and may cause significant damage to our business. The harm to our business from a breach of confidentiality cannot presently be quantified but may be material and may not be compensable in damages. There is no assurance that, in the event of a breach of confidentiality, we will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to our business that such a breach of confidentiality may cause.

New Industry Related Activities or New Geographical Areas

The operations and expertise of our management are currently focused primarily on oil and gas production, exploration and development in the Western Canada Sedimentary Basin. In the future we may acquire or move into new industry related activities or new geographical areas, may acquire different energy related assets, and as a result may face unexpected risks or alternatively, significantly increase our exposure to one or more existing risk factors, which may in turn result in our future operational and financial conditions being adversely affected.

Risks Related to Our Debt and Securities

Level of Indebtedness

Our indebtedness could have important consequences to us, including:

- limiting our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of our development plans or other purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service the indebtedness;
- increasing our vulnerability to general adverse economic and industry conditions, including increases in interest rates;
- limiting our ability to capitalize on business opportunities and to react to competitive pressures and adverse changes in government regulation; and
- limiting our ability, or increasing the costs, to refinance indebtedness.

Restrictions in Our Debt Instruments

Our debt agreements including the 2022 Notes and the Amended Credit Facility include covenants that, among other things, restrict the ability of Athabasca and its subsidiaries to:

- incur indebtedness;
- make restricted payments, including paying dividends and prepaying junior debt;
- make investments;
- create liens;
- sell assets; or
- engage in mergers or acquisitions.

Our failure to comply with these covenants would likely result in an event of default under our debt agreements. Such a default could allow the creditors to accelerate the related indebtedness and result in acceleration of our other indebtedness to which a cross-acceleration or cross-default provision applies. In the event that noteholders accelerate the repayment of our indebtedness, we may not have sufficient assets or be able to borrow sufficient funds to repay or refinance that indebtedness.

The available lending limits of the Amended Credit Facility are reviewed semi-annually and are based on the lenders' assessment of the Company's reserves and future commodity prices as well as the application of applicable discount rates and other factors by the lenders, including their respective normal petroleum and natural gas lending criteria and practices in effect at the time of such review for loans to borrowers in the Canadian petroleum and natural gas industry. A material decline in commodity prices or the value of our reserves could reduce the available lending limits under the Amended Credit Facility, therefore reducing the funds available to the Company which could result in a portion, or all, of the Company's indebtedness under the Amended Credit Facility being required to be repaid. The acceleration of our indebtedness under the Amended Credit Facility may permit acceleration of indebtedness under other agreements relating to our secured debt that contain cross default or cross-acceleration provisions.

If Athabasca experiences certain changes in control, Athabasca may be required to make an offer to repurchase all of the outstanding 2022 Notes prior to their maturity at 101% of their principal amount. Additionally, under the Amended Credit Facility, certain changes in control may permit the lenders to accelerate the maturity of borrowings under such facilities, terminate their commitments to lend and require repayment of amounts drawn under the Amended Credit Facility. Athabasca may not have sufficient funds or be able to arrange for additional financing at the time of the change of control to make the required repurchase of the 2022 Notes and repay any of Athabasca's other indebtedness that may also become due.

Additional Indebtedness

Despite our current level of indebtedness, we may still be able to incur substantially more debt, which could further exacerbate the risks associated with our leverage.

Issuance of Additional Securities

The Board may issue an unlimited number of Common Shares, without any vote or action by Athabasca's Shareholders, subject to the rules of the TSX or such other stock exchange on which Athabasca's securities may be listed from time to time. Athabasca may make future acquisitions or enter into financings or other transactions involving the issuance of securities. In addition, Athabasca may issue Stock Options, Performance Awards and RSUs exercisable to acquire up to 10% of the number of Common Shares outstanding at any given time. If Athabasca issues any additional Common Shares, the percentage ownership of existing Shareholders will be reduced and diluted.

As a result of the foregoing factors, purchasers of Common Shares may not receive any return on an investment in Common Shares unless they sell such Common Shares for a price greater than that which they paid for it.

ADDITIONAL INFORMATION

Additional information relating to the Company can be found on SEDAR at *www.sedar.com*. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of securities and securities authorized for issuance under the Company's equity compensation plans, is contained in the Information Circular for the Company's most recent annual meeting of securityholders that involved the election of directors. Additional financial information about Athabasca is provided in the Company's financial statements and management's discussion and analysis for the year ended December 31, 2019, which may be found on SEDAR at *www.sedar.com*

GLOSSARY OF DEFINED TERMS

Capitalized terms in this Annual Information Form have the meanings set forth below. Unless other indicated, references herein to "$" or "dollars" are to Canadian dollars.

"**2022 Note Indenture**" means the indenture dated February 24, 2017, among the Company, the Company's subsidiary guarantors, the Bank of New York Mellon and the BNY Trust Company of Canada relating to the 2022 Notes.

"**2022 Notes**" has the meaning given to such term under the heading "*Development of Our Business - Developments in 2017*".

"**ABCA**" means the *Business Corporations Act*, R.S.A. 2000, c. B-9, as amended, including the regulations promulgated thereunder.

"**Acquisition Royalty**" has the meaning given to that term under "*Development of Our Business – Developments in 2017*".

"**AER**" means the Alberta Energy Regulator.

"**Amended Credit Facility**" has the meaning given to that term under "*Capital Structure – Revolving Senior Secured Credit Facility*".

"**Amended Rights Plan**" has the meaning given to such term under "*Capital Structure – Shareholder Rights Plan*."

"**API**" refers to an indication of the specific gravity of crude oil measured on the American Petroleum Institute gravity scale.

"**Athabasca**" means "we", "our", "us", or the "Company" or Athabasca Oil Corporation and/or its wholly-owned subsidiaries, as the context requires.

"**Audit Committee**" means the audit committee of the Board.

"**Best Estimate**" has the meaning given to that term under "*Appendix A – Supplemental Disclosure - Contingent Resource Estimates*".

"**Birch assets**" means the interests of Athabasca in approximately 286,000 net acres of land located in northeastern Alberta (see map) as at December 31, 2019, that are more particularly described under "*Description of Our Business – Thermal Oil Exploration Areas – Birch Assets* ".

"**bitumen**" means a naturally occurring solid or semi-solid hydrocarbon, consisting mainly of heavier hydrocarbons with a viscosity greater than 10,000 milliPascal seconds (or centipoise) measured at the hydrocarbon's original temperature in the reservoir and atmospheric pressure, on a gas-free basis and is not primarily recoverable at economic rates through a well without the implementation of enhanced recovery methods. Crude bitumen may contain sulphur and other non-hydrocarbon compounds.

"**Board**" means the Board of Directors of the Company.

"**Burgess**" has the meaning given to that term under "*Development of Our Business – Developments in 2017*".

"**carbonate**" means a class of sedimentary rock whose chief mineral constituents (95% or more) are calcite, aragonite and dolomite. Limestone, dolostone (or dolomite) and chalk are carbonate rocks. Although carbonate rocks can be clastic in origin, they are more commonly formed through processes of precipitation or the activity of organisms such as coral and algae. Carbonates form in shallow and deep marine settings, evaporitic basins, lakes and windy deserts. Carbonate rocks are common hydrocarbon reservoir rocks.

"**clastic**" means sediment consisting of weathered fragments derived from pre-existing rocks and transported elsewhere and redeposited before forming another rock. Examples of common clastic sedimentary rocks include siliciclastic rocks such as conglomerate, sandstone, siltstone and shale.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter) as amended from time to time.

"**Collateral Agent Agreement**" has the meaning given to that term under "*Capital Structure – 2022 Notes*".

"**Common Shares**" means the common shares in the capital of the Company, as constituted on the date hereof.

"**Company Interest**" means Athabasca's total working interest share before deduction of royalties and without excluding any royalty interests.

"**Compensation and Governance Committee**" means the compensation and governance committee of the Board.

"**Contingent Resources**" has the meaning given to that term under "*Appendix A – Supplemental Disclosure - Contingent Resource Estimates*".

"**conventional natural gas**" means 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.

"**Corner assets**" means the interests of Athabasca in approximately 44,000 net acres of oil sands leases (not including overlying petroleum and natural gas leases) located in the Athabasca oil sands fairway in northeastern Alberta (see map) as at December 31, 2019, that are more particularly described under "*Description of Our Business – Thermal Oil Division – Leismer Corner Assets*" and "*Appendix "A"- Supplemental Disclosure - Contingent Resource Estimates*".

"**Corner Project**" means Corner Project 1 and Corner Project 2.

"**Corner Project 1** "means a SAGD project to be located in the Corner asset area with a production capacity of up to 40,000 bbl/d.

"**Corner Project 2**" means a SAGD expansion phase of the Corner Project to be located in the Corner asset area with a production capacity of up to 50,000 bbl/d.

"**CPF**" means central processing facility.

"**crude oil**" or "**oil**" means a mixture consisting mainly of pentanes and heavier hydrocarbons that exist in the liquid phase in reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons but does not include liquids obtained from the processing of natural gas. Classes of crude are reported on basis of density, acceptable ranges are as follows: Light: less than 870kg/m3 (greater than 31.1 degrees (symbol) API), Medium: 870-920 kg/m3 (31.1-22.3 degrees API), Heavy 920-1000 kg/m3 (22.3-10 degrees API).

"**developed non-producing reserves**" has the meaning given to that term under "*Statement of Reserves Data – Reserves Classifications – Development and Production Status*".

"**developed producing reserves**" has the meaning given to that term under "*Statement of Reserves Data – Reserves Classifications – Development and Production Status*".

"**developed reserves**" has the meaning given to that term under "*Statement of Reserves Data – Reserves Classifications – Development and Production Status*".

"**dilbit**" means a blend of condensate and bitumen.

"**diluent**" means lighter viscosity petroleum products that are used to dilute bitumen for purposes such as transportation in pipelines.

"**Dover West assets**" means the interests of Athabasca in approximately 155,000 net acres of land as at December 31, 2019 located within the Athabasca oil sands fairway in northeastern Alberta (see map) that are more particularly described under "*Description of Our Business – Thermal Oil Exploration Areas – Dover West Assets*" and "*Appendix "A"- Supplemental Disclosure- Contingent Resource Estimates*".

"**Dover West Sands**" means the clastic bitumen reservoirs contained within the McMurray Formation and the Wabiskaw member of the Clearwater Formation in the Dover West assets.

"**Dover West Sands Project 1**" means a SAGD project in the Dover West area with a planned production capacity of up to 50,000 bbl/d.

"**DSU**" means a deferred share unit granted under the Company's deferred share unit plan which was originally made effective for directors of the Company on March 11, 2015 and as amended from time to time.

"**EBITDA**" means earnings before interest, tax, depreciation and amortization.

"**Enbridge**" means Enbridge Inc. or any of its subsidiaries.

"**ERCB**" means the Energy Resources Conservation Board of Alberta (predecessor to the AER).

"**Established Technology**" means methods that have been proven to be successful in commercial applications, as such term is defined in the COGE Handbook.

"**FEED**" means front end engineering and design.

"**forecast prices and costs**" means future prices and costs that are: (a) generally accepted as being a reasonable outlook of the future; or (b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which Athabasca is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in subparagraph (a).

"**future net revenue**" means a forecast of revenue, estimated using forecast prices and costs or constant prices and costs, arising from the anticipated development and production of resources, net of the associated royalties, operating costs, development costs, and abandonment and reclamation costs.

"**GHG**" means greenhouse gas.

"**Grosmont assets**" refers to Athabasca's interest in approximately 110,000 net acres of land in the Grosmont (Mikwa) area located in northeastern Alberta as at December 31, 2019 (see map), as more particularly described under "*Description of Our Business – Thermal Oil Exploration Areas*".

"**gross**" means in relation to reserves: the Company's working interest volumes (operating or non-operating) before deduction of royalties and without including any royalty interests of the Company; in relation to properties: the total area in which the Company has an interest; in relation to wells: the total number of wells the Company has an interest in.

"**Hangingstone assets**" means the interests of Athabasca in approximately 86,000 net acres of land located in the Athabasca oil sands fairway in northeastern Alberta (see map) as at December 31, 2019 with up to 80,000 bbl/d producing capacity, that are more particularly described under "*Description of Our Business – Thermal Oil Division – Hangingstone Assets*".

"**Hangingstone Project**" means a producing SAGD project in the Hangingstone area of northwestern Alberta with plant capacity of up to 12,000 bbl/d.

"**hydrocarbon**" means a compound consisting of hydrogen and carbon, which, when naturally occurring, may also contain other elements such as sulphur.

"**in-situ**" means "in place" and, when referring to oil sands, means a process for recovering bitumen from oil sands by means other than surface mining, such as SAGD.

"**Kaybob assets**" means the interests of Athabasca in approximately 80,000 net acres of land that are located primarily in northwestern Alberta (see map), as at December 31, 2019, as more particularly described under "*Description of Our Business – Light Oil Division*".

"**Kaybob Carry Commitment**" means Murphy's obligation to fund 75% of Athabasca's share of Duvernay development capital up to $1 billion of gross investment ($75 million net capital exposure to Athabasca).

"**Kaybob JDA**" means the joint development agreement between the Company and Murphy dated May 13, 2016.

"**LC Facility**" has the meaning given to that term under "*Capital Structure – LC Facilities*".

"**Leismer assets**" means the interests of Athabasca in approximately 78,000 net acres of oil sands leases (not including overlying petroleum and natural gas leases) located in the Athabasca oil sands fairway in northeastern Alberta (see map) as at December 31, 2019 with up to 80,000 bbl/d producing capacity, that are more particularly described under "*Description of Our Business – Thermal Oil Division – Leismer Corner Assets*" and "*Appendix "A" - Supplemental Disclosure - Contingent Resource Estimates*".

"**Leismer Corner assets**" has the meaning given to that term under " *Description of Our Business – Thermal Oil Division - Leismer Corner Assets*".

"**Leismer Project**" means a producing SAGD project in Northwestern Alberta with plant capacity up to 25,000 bbl/d which was acquired from Statoil on January 31, 2017.

"**Leismer Project 2**" means a SAGD expansion phase of the Leismer assets with a production capacity of up to 15,000 bbl/d.

"**Leismer Project 3**" a SAGD expansion phase of the Leismer assets with a production capacity of up to 40,000 bbl/d.

"**LIBOR**" means the London Inter-bank Offered Rate.

"**Light Crude Oil**" or "**light crude oil**" means crude oil with a relative density greater than 31.1 degrees API gravity.

"**Light Oil assets**" means the interests of Athabasca in approximately 259,200 net acres of land as at December 31, 2019, primarily located in northwestern Alberta, which includes the Kaybob assets, Placid assets and Light Oil Exploration Areas.

"**Light Oil Division**" means Athabasca's business unit which is primarily focused on the exploration for, and sustainable development and production of, light oil and liquids-rich natural gas.

"**Light Oil Exploration Areas**" means the interests of Athabasca in approximately 110,000 net acres of land that are located in the Grande Prairie, Karr, Caribou, Glenevis, Rainbow Lake North and Rainbow Lake South areas in northwestern Alberta as at December 31, 2019.

"**LMR**" means liability management rating and is the ratio of a company's assets to its liabilities, for a discussion of how a company's LMR is used, see *"Industry Conditions - Liability Management Rating Program".*

"**McDaniel**" means McDaniel & Associates Consultants Ltd., an independent qualified reserve and resource evaluator.

"**McDaniel Report**" means the report prepared by McDaniel dated effective as of December 31, 2019, assessing and evaluating the Proved Reserves and Probable Reserves of the Company located in the Leismer, Corner, Hangingstone and Light Oil assets and the Contingent Resources located in the Leismer, Corner and Dover West Sands assets.

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

"**Murphy**" means Murphy Oil Canada Ltd., a wholly owned subsidiary of Murphy Oil Corporation.

"**M$**" means thousands of Canadian dollars.

"**MM$**" means millions of Canadian dollars.

"**natural gas**" means a naturally occurring mixture of hydrocarbon gases and other gases, which may contain sulphur or other non-hydrocarbon compounds.

"**net acres**" means the percentage of total acres an owner owns out of a specific number of acres or specified area.

"**Net Reserves**" means Athabasca's working interest (operating or non-operating) share after deduction of royalty obligations, plus Athabasca's royalty interests in reserves.

"**NGL**" or "**natural gas liquids**" means the hydrocarbon components that can be recovered from natural gas as liquids, including, but not limited to ethane, propane, butanes, pentanes plus and condensates.

"**NI 51-101**" means National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities*.

"**NI 51-102**" means National Instrument 51-102 *Continuous Disclosure Obligations.*

"**oil sands**" means deposits of sand, sandstone, carbonate or other mineral material containing bitumen.

"**Performance Award**" means performance awards able to be granted under the Company's Performance Plan.

"**Performance Plan**" means the performance award plan of the Company which was originally effective March 18, 2014 and as amended from time to time.

"**permeability**" is a measure of the ability of a rock to conduct a fluid through its interconnected pores when that fluid is at 100% saturation. A rock may be highly porous and yet impermeable if it has no interconnecting pore network (communication). Permeability is measured in darcies or millidarcies.

"**PIIP**" means that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of discovered petroleum initially-in-place includes production, reserves and Contingent Resources; the remainder is unrecoverable.

"**Placid assets**" means the interests of Athabasca in approximately 69,000 net acres of land located primarily in northwestern Alberta (see map), as at December 31, 2019 as more particularly described under "*Description of Our Business – Light Oil Division*".

"**Placid JDA**" means the joint development agreement between the Company and Murphy dated May 13, 2016.

"**porosity**" means the volume of a rock available to contain fluids; the ratio of void space to the bulk volume of rock containing that void space. Porosity can be expressed as a fraction or percentage of pore volume in a volume of rock.

"**Probable Reserves**" or "**probable reserves**" has the meaning given to that term under "*Statement of Reserves Data - Reserves Classifications – Reserves Categories*".

"**Proved Reserves**" or "**proved reserves**" has the meaning given to that term under " *Statement of Reserves Data – Reserves Classifications – Reserves Categories*".

"**recovery factor**" means the percentage of PIIP in a reservoir that ultimately can be recovered at a specific point in time.

"**Reserves**" or "**reserves**" has the meaning given to that term under "*Statement of Reserves Data – Reserves Classifications – Reserves Categories*".

"**Reserves Committee**" means the reserves committee of the Board.

"**reservoir**" means a porous and permeable formation that contains a separate accumulation of petroleum that is confined by impermeable rock or water barriers and is characterized by a single pressure system.

"**Rights Plan**" means the shareholder rights plan of the Company as described under "*Capital Structure – Shareholder Rights Plan*".

"**risked**" has the meaning given to that term under "*Appendix A – Supplemental Disclosure - Contingent Resource Estimates*".

"**Royalty**" means a contingent bitumen royalty granted to Burgess Energy Holdings L.L.C. on the Company's oilsands assets located at Hangingstone, Dover West, Birch and Grosmont on June 20, 2016. Payment of the applicable royalty rate is tied to US$ WCS benchmark prices and calculated on a linear scale ranging from 0-12% of the Company's realized bitumen price ($C), with the royalty rate beginning at 2% when US$ WCS reaches $60/bbl in the case of Hangingstone and $70/bbl in the case of Dover West, Birch and Grosmont. The realized price is determined net of diluent, transportation and storage costs and have been structured so that the assets will not be encumbered at lower pricing levels.

"**RSU**" means a restricted share unit granted under the restricted share unit plan of the Company originally effective February 24, 2010, as amended from time to time.

"**S&P**" means Standard and Poor's Global Rating Services, a division of S&P Global Inc.

"**SAGD**" means steam assisted gravity drainage, an in-situ process used to recover bitumen from oil sands.

"**saturation**" is the fraction or percentage of the pore volume occupied by a specific fluid (e.g., oil, gas, water, etc.).

"**SCO**" or "**synthetic crude oil**" means a mixture of liquid hydrocarbons derived by upgrading bitumen, kerogen or other substances such as coal, or derived from gas to liquid conversion and may contain sulphur or other compounds.

"**shale gas**" means natural gas contained in dense organic-rich rocks, including low permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay materials and that usually requires the use of hydraulic fracturing to achieve economic production rates.

"**Shareholders**" means the holders, from time to time, of the Common Shares, collectively or individually, as the context requires.

"**SOR**" means steam to oil ratio.

"**Statoil**" means Statoil ASA or Statoil Canada Limited, now Equinor Canada Ltd.

"**Stock Option**" means a stock option granted under the stock option plan of the Company originally dated effective as of September 1, 2009, as amended from time to time.

"**technology under development**" means a recovery process or process improvement project that has been determined to be technically viable via a field test and is being field tested further to determine its economic viability in the subject reservoir as such term is defined in the COGE Handbook.

"**Thermal Oil assets**" means the interests of Athabasca in approximately 760,000 net acres of oil sands leases in the Athabasca region of northeastern Alberta, as at December 31, 2019.

"**Thermal Oil Division**" means Athabasca's business unit which is primarily focused on the exploration for, and sustainable development and production of, bitumen from oil sands.

"**tight oil**" means crude oil contained in dense organic-rich rocks, including low permeability shales, siltstones and carbonates, in which the natural gas is primarily contained in microscopic pore spaces that are poorly connected to one another and that usually requires the use of hydraulic fracturing to achieve economic production rates.

"**TSX**" means the Toronto Stock Exchange.

"**undeveloped reserves**" has the meaning given to that term under "*Statement of Reserves Data – Reserves Classifications – Development and Production Status*".

"**unrisked**" has the meaning given to that term under "*Appendix A – Supplemental Disclosure - Contingent Resource Estimates*".

"**WCS**" means Western Canadian Select.

"**WI**" means working interest.

"**WTI**" means West Texas Intermediate grade crude oil at a reference sales point in Cushing, Oklahoma, a common benchmark for crude oils.

Certain other terms used herein but not defined herein are defined in NI 51-101 or the COGE Handbook and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 or the COGE Handbook.

APPENDIX A

SUPPLEMENTAL DISCLOSURE - CONTINGENT RESOURCE ESTIMATES AS AT DECEMBER 31, 2019

Athabasca engaged McDaniel to prepare Contingent Resource evaluations of its Leismer, Corner, and Dover West Sands assets. All of Athabasca's Contingent Resources have been evaluated in accordance with NI 51-101. McDaniel's Report on Contingent Resources Data by Independent Qualified Reserves Evaluator or Auditor is set forth in Appendix "C" to this Annual Information Form.

Quantities of Contingent Resources may be estimated using low estimate (high certainty), Best Estimate (most likely) and high estimate (low certainty) cases. In this Annual Information Form, Athabasca has reported its Contingent Resources using the Best Estimate case, which is considered to be the best estimate of the quantity of Contingent Resources that may actually be recovered. All of the Company's Contingent Resources disclosed herein are classified under the product type of bitumen resources. It should not be assumed that the estimates of recovery, production and net revenue that are reflected in the table that is provided below represent the fair market value of Athabasca's bitumen resources. There is no assurance that the forecast prices and cost assumptions will be realized and variances could be material and there is no guarantee that the estimated resources will be recovered or produced. Actual resources may be greater than or less than the estimates provided herein. There is no certainty that it will be commercially viable for Athabasca to produce any portion of the Contingent Resources on any of its properties.

The Contingent Resources estimates presented in the Independent Report are based upon the definitions and guidelines contained in the COGE Handbook. A summary of the applicable definitions is set forth below:

"**Best Estimate**" is a classification of estimated resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will actually be recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the Best Estimate. If probabilistic methods are used, there should be a 50% probability (P50) that the quantities actually recovered will equal or exceed the Best Estimate.

"**chance of development**" means the estimated probability that, once discovered, a known accumulation will be commercially developed.

"**Contingent Resources**" are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies may include such factors as economic, legal, environmental, political and regulatory matters or a lack of markets. It is also appropriate to classify as "Contingent Resources" the estimated discovered recoverable quantities associated with a project in the early evaluation stage.

"**Economic**" means those Contingent Resources that are currently economically recoverable based on the same fiscal conditions used in the assessment of reserves.

"**risked**" means the applicable reported volumes or revenues <u>have been</u> risked (or adjusted) based on the chance of commerciality of such resources in accordance with the COGE Handbook. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore, risked reported volumes and values of contingent resources reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

"**unrisked**" means applicable reported volumes or values of resources <u>have not been</u> risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore, unrisked reported volumes and values of contingent resources do not reflect the risking (or adjustment) of such volumes or values based on the chance of development of such resources.

Contingent Resources may be divided into the following project maturity sub-classes:

"**Development Pending**" is assigned to Contingent Resources for a particular project where resolution of the final conditions for development is being actively pursued (high chance of development).

"**Development on Hold**" is assigned to Contingent Resources for a particular project where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

"**Development Unclarified**" is assigned to Contingent Resources for a particular project where evaluation is incomplete and there is ongoing activity to resolve any risks or uncertainties or which require significant further appraisal to clarify potential for development and where contingencies have yet to be defined.

"**Development Not Viable**" is assigned to Contingent Resources for a particular project where no further data acquisition or evaluation is currently planned and there is a low chance of development.

Other terms not defined in this Appendix "A" have the meaning ascribed to such terms under "*Glossary of Defined Terms*" in the main body of this Annual Information Form.

The following tables set forth: (a) the unrisked Best Estimate Contingent Resources; (b) the risked Best Estimate Contingent Resources; and (c) the associated risked future net revenue (before income taxes) estimates for the Contingent Resources calculated by McDaniel in the Independent Report. The evaluation procedure employed by McDaniel is in accordance with the standards set forth in the COGE Handbook. The price forecasts that formed the basis for the net present value estimates that are contained herein were based on McDaniel's January 1, 2020 pricing models set forth below under "*Forecast Prices & Costs Used in Contingent Resource Estimates*". There is no assurance that the forecast price and cost assumptions used will be realized and variances could be material. See "*Forward Looking Statements*" in this Annual Information Form.

An estimate of risked net present value of future net revenue of Contingent Resources is preliminary in nature and is provided to assist the reader in reaching an opinion on the merit and likelihood of Athabasca proceeding with the required investment. It includes Contingent Resources that are considered too uncertain with respect to the chance of development to be classified as reserves. There is uncertainty that the risked net present value of future net revenue will be realized.

Summary of Unrisked and Risked Contingent Resources and Risked Net Present Value of Future Net Revenue (Best Estimate Contingent Resources)(1,2,3,4,5,6,7,8,9,10)

Project Maturity Sub-Class	Working Interest	Gross Unrisked Best Estimate Contingent Resources	Chance of Development	Gross Risked Best Estimate Contingent Resources	Net Risked Best Estimate Contingent Resources	Risked Net Present Value of Future Net Revenue Before Income Tax Discounted at (%/year) 0%	5%	10%	15%	20%
	(%)	(MMbbl)	(%)	(MMbbl)	(MMbbl)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
Thermal Oil Assets										
Leismer Pending	100%	354	90%	**319**	877	5,083	1,598	484	85	-65
Corner Pending	100%	520	80%	**416**	1,601	8,180	2,227	636	152	-3
Dover West Sands on Hold	100%	2,244	60%	**1,346**	24,095	18,186	2,587	9	-361	-334
Total: Thermal Oil assets	100%	3,118	67%	**2,081**	26,574	31,449	6,411	1,130	-123	-403

Notes:

1. See definitions for "Contingent Resources", "Best Estimate", "risked", "unrisked" "Development Pending", "Development on Hold" and "Development Unclarified" above.
2. The volumes of Contingent Resources in this table were calculated at the outlet of the proposed extraction plant.
3. There is no certainty that it will be commercially viable to produce any portion of the Contingent Resources.
4. The Contingent Resource estimates set out in the table reflect, as at December 31, 2019, Athabasca's working interest in the Leismer, Corner and Dover West Sands assets.
5. Based on the estimates contained in the Independent Report dated effective as of December 31, 2019, calculated by McDaniel using McDaniel's pricing forecasts for consistency and in accordance with the COGE Handbook.
6. Totals may not add due to rounding.
7. Gross unrisked Contingent Resource volumes have been included to provide a comparison with the Company's Contingent Resources disclosure from previous years in which risking was not included (prior to 2016).
8. All of the Company's Contingent Resources are of the bitumen product type.
9. All evaluations of future revenue are after the deduction of royalties, development costs, production costs and well abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. For a further discussion of what is and isn't included in abandonment and reclamation costs, please see "*Abandonment and Reclamation Costs*" below.
10. The estimates of Contingent Resources (Best Estimate) and future net revenue for individual properties may not reflect the same confidence levels as estimates of Contingent Resources (Best Estimate) and future net revenues for all properties, due to the effects of aggregation.

Forecast Prices & Costs Used in Contingent Resource Estimates

Year	Inflation	Exchange Rate	WTI Crude Oil	Edmonton Light Crude Oil	Western Canadian Select Crude Oil	US Henry Hub Gas	AECO Spot Gas	Pentanes Edmonton	Butane Edmonton	Propane Edmonton
	%	US$/C$	US$/bbl	C$/bbl	C$/bbl	US$/MMBtu	C$/MMBtu	C$/bbl	C$/bbl	C$/bbl
2020	0	0.76	$61.00	$72.64	$57.57	$2.62	$2.04	$76.83	$42.10	$26.36
2021	1.7	0.77	$63.75	$76.06	$62.35	$2.87	$2.32	$79.82	$47.03	$29.80
2022	2	0.79	$66.18	$78.35	$64.33	$3.06	$2.62	$82.30	$50.66	$32.94
2023	2	0.79	$67.91	$80.71	$66.23	$3.17	$2.71	$84.72	$52.21	$34.00
2024	2	0.79	$69.48	$82.64	$67.97	$3.24	$2.81	$86.71	$53.48	$34.88
2025	2	0.79	$71.07	$84.60	$69.72	$3.32	$2.89	$88.73	$54.77	$35.78
2026	2	0.79	$72.68	$86.57	$71.49	$3.39	$2.96	$90.77	$56.07	$36.69
2027	2	0.79	$74.24	$88.49	$73.20	$3.45	$3.03	$92.76	$57.32	$37.57
2028	2	0.79	$75.73	$90.31	$74.80	$3.53	$3.09	$94.65	$58.50	$38.41
2029	2	0.79	$77.24	$92.17	$76.43	$3.60	$3.16	$96.57	$59.71	$39.26
2030	2	0.79	$78.79	$94.01	$77.96	$3.67	$3.23	$98.50	$60.90	$40.04
2031	2	0.79	$80.36	$95.89	$79.52	$3.74	$3.29	$100.47	$62.12	$40.85
2032	2	0.79	$81.97	$97.81	$81.11	$3.82	$3.36	$102.48	$63.36	$41.66
2033	2	0.79	$83.61	$99.76	$82.73	$3.89	$3.43	$104.53	$64.63	$42.50
2034	2	0.79	$85.28	$101.76	$84.39	$3.97	$3.49	$106.62	$65.92	$43.35
Thereaft	2	flat	~2%/year	~2%/year	~2%/year	~2%/year	~2%/year	~2%/year	~2%/year	~2%/year

Description of Leismer Contingent Resources

The Contingent Resources assigned to Athabasca's Leismer assets assume that such resources will be produced using SAGD technology which has been successfully implemented at the Leismer Project since 2010. The production of Contingent Resources assigned to the Leismer assets is contingent upon the completion of Leismer Project 3 which, if commissioned, is planned to be on stream in 2027 with a capacity of 40,000 bbl/d which would take the total Leismer plant capacity to 80,000 bbl/d.

A field development plan has been developed for the Leismer assets but the existing environmental impact assessment is for capacity of 40,000 bbl/d and an amendment for 80,000 bbl/d has not been submitted to date.

The infrastructure already in place to support Leismer Project 3 includes the access road to the CPF, the diluent import pipeline, capacity on the dilbit sales pipeline to Cheecham, tank capacity at Cheecham and the gas import pipeline. However, the existing pipelines and tankage will require debottlenecking to be able to accept the volumes from Leismer Project 3.

Based on Athabasca's development plan, the total Best Estimate capital cost of first commercial production in 2027 for the Leismer Project 3 is estimated at approximately $1,487 million (uninflated, unrisked, undiscounted) which includes delineation, SAGD well pairs and central processing facilities.

The contingencies identified for the development of the Leismer Contingent Resources are:

- Regulatory Approval – filing an amendment to the existing Leismer application.
- Market Conditions – the Leismer Project 3 is not expected to be sanctioned by the Board until market conditions improve and project funding is secured.
- Delineation – further delineation is required before a final investment decision can be made.
- Firm development plans and detailed cost estimates - have not yet been developed.
- Project Timing – Leismer Project 3 is not anticipated to start up until 2027 and significant spending is not anticipated before 2024.

In accordance with the COGE Handbook, Leismer risked Best Estimate Contingent Resources have been classified as Development Pending by McDaniel. These Contingent Resources are considered to be Development Pending as they are within 10 miles of the existing CPF and there is sufficient delineation to prepare the development strategy consistent with a project evaluation scenario status of development. Athabasca is actively working on this property and there is corporate intent to develop the Contingent Resources in the near term. First steam is planned for 2027 subject to project sanctioning. The Hangingstone Project took 4.5 years from commencing preparation of the regulatory application to first steam. Athabasca will execute the Leismer Project 3 with the same proven execution strategy and facility design and consequently does not need to do further work on the Leismer Project 3 until 2024 to maintain a reasonable expectation of reaching first steam in 2027. The level of economic analysis is sufficient to assess the development options and overall project viability but is insufficient for a final investment decision. The chance of development of these Contingent Resources is estimated to be 90%.

The positive factors relevant to the Contingent Resource estimates for the Leismer Project 3 include:

- They are within a 10 mile radius of the existing CPF and significant infrastructure is already in place.
- Using established technology which is being successfully implemented at the Leismer Project.
- A development plan is in place.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the project maturity sub-class of Development Pending.

The negative factors relevant to the Contingent Resource estimates for the Leismer Project include:

- Economic sensitivity to future oil pricing.

- Existing infrastructure requires debottlenecking.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- The Leismer regulatory application has not yet been amended for Leismer Project 3.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Description of Corner Contingent Resources

The Contingent Resources assigned to Athabasca's Corner assets assumes the resources will be produced using SAGD technology which has been successfully implemented in the nearby Leismer Project since 2010. The production of the Contingent Resources assigned to the Corner assets is contingent upon the completion of the second phase which, if commissioned, is planned to be on stream in 2030 with a capacity of 50,000 bbl/d which would take the total Corner plant capacity to 90,000 bbl/d.

A field development plan has been developed for the Corner assets but the existing environmental impact assessment is for capacity of 40,000 bbl/d and an amendment for 90,000 bbl/d capacity has not been submitted.

There is no infrastructure already in place to support the Corner Project although some of the nearby Leismer plant infrastructure could be used, which includes the access road to the CPF, the diluent import pipeline, capacity in the dilbit sales pipeline to Cheecham, and tank capacity at Cheecham.

Based on Athabasca’s development plan, the total Best Estimate capital cost of first commercial production in 2030 for the Corner Project 2 is estimated at approximately $1,740 million (uninflated, unrisked, undiscounted) which includes delineation, SAGD well pairs and central processing facilities.

The contingencies identified for the development of the Corner Contingent Resources are:

- Regulatory Approval – filing an amendment to the existing Corner application.
- Market Conditions – Corner Project 2 is not expected to be sanctioned by the Board until market conditions improve and project funding is secured.
- Delineation – further delineation is required before a final investment decision can be made.
- Firm development plans and detailed cost estimates - have not yet been developed.
- Project Timing – Corner Project 2 is not anticipated to start up until 2030 and significant spending is not anticipated before 2027.

In accordance with the COGE Handbook, Corner risked Best Estimate Contingent Resources have been classified as Development Pending by McDaniel. These Contingent Resources are considered to be Development Pending as they are within a 10 mile radius of the CPF that will be constructed for the Corner Reserves and as there is sufficient delineation to prepare the development strategy consistent with a project evaluation scenario status of development. Athabasca is actively working on this property and intends to develop it in the near term, subject to project sanctioning. The Hangingstone Project took 4.5 years from commencement of preparation of the regulatory application to first steam. Athabasca will execute Corner Project 2 with the same proven execution strategy and facility design and consequently does not need to do further work on Corner Project 2 until 2025 to maintain a reasonable expectation of reaching first steam in 2030. The level of economic analysis is sufficient to assess the development options and overall project viability but is insufficient for a final investment decision. The chance of development of these Contingent Resources is estimated to be 80%.

The positive factors relevant to the Contingent Resource estimates for the Corner Project include:

- The Contingent Resources are located within a 10 mile radius of a CPF that will be constructed for Corner Project 1.
- Using established technology which is being successfully implemented in the nearby Leismer Project.
- A pre-development plan is in place.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic. The level of delineation supports the risks assigned to the project maturity sub-class of Development Pending.

The negative factors relevant to the Contingent Resource estimates for the Corner Project include:

- Economic sensitivity to future oil pricing.
- Existing infrastructure requires debottlenecking.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- The Corner regulatory application has not yet been amended for Corner Project 2.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Description of Dover West Sands Contingent Resources

The estimates of Contingent Resources assigned to Athabasca's Dover West Sands assets assume that such resources will be produced using SAGD technology. There are adequate analogues in the area and reservoir studies to confirm that SAGD is applicable to the Dover West reservoir. Athabasca will leverage the experience gained in successfully delivering the Hangingstone Project during 2015 to deliver the Dover West Sands Project 1. The commencement of production from the Dover West Sands resources is contingent upon the commissioning and completion of the 50,000 bbl/d Dover West Sands Project 1 for which first oil is forecast in 2031. If commissioned and completed, the second phase of the Dover West Sands Project is expected to have a capacity of 50,000 bbl/d with first oil expected in 2034. If commissioned and completed, two subsequent 50,000 bbl/d phases may follow in 2035 and 2037 to the expected ultimate approximate capacity of 200,000 bbl/d.

The regulatory application for the Dover West Sands Project 1 was submitted to the ERCB (now the AER) in December 2011. The application process was prolonged as the Company was focused on resolving a statement of concern. In 2019 we withdrew the regulatory application given the challenge to finance projects in the present commodity price environment, the considerable uncertainty in regulatory and royalty regimes and Athabasca’s focus on its Leismer, Corner and Hangingstone Projects. The withdrawal of the Application did not change the classification of the Dover West Sands resources as the volumes had already been reclassified to Contingent Resources in December 31, 2015.

The only infrastructure already in place to support the Dover West Sands Project 1 is an access road.

Based on Athabasca’s development plan, the total Best Estimate capital cost of first commercial production in 2031 for Dover West Sands Project 1 is estimated at approximately $3,000 million (uninflated, unrisked, undiscounted) which includes delineation, SAGD well pairs and central processing facilities.

The contingencies identified for the development of the Dover West Sands Contingent Resources are:

- Regulatory Approval – an application has been filed but approval has not yet been granted.
- Corporate Commitment – the Dover West Sands project is not expected to be sanctioned by the Board until market conditions improve and project funding is secured.
- Delineation – development level delineation has only been achieved in the area of the reservoir that would be produced by Dover West Sands Project 1. Further delineation is required in the remaining area before a final investment decision can be made.

In accordance with the COGE Handbook, the risked Best Estimate Dover West Sands Contingent Resource volumes have been classified as Development On Hold by McDaniel. These Contingent Resources are considered by McDaniel to be classified as Development On Hold because regulatory approval has not yet been granted and also due to current industry economic conditions. The Company does not expect to produce these resources prior to 2031. There is, however, 3D seismic and development level delineation across the Dover West Sands area, a development plan is in place and FEED has been completed for the Dover West Sands Project 1. The level of economic analysis is sufficient to assess development options and overall project viability, but is insufficient for a final investment decision. The chance of development of these Contingent Resources is estimated to be 60%.

The positive factors relevant to the Contingent Resource estimates for Dover West Sands include:

- Using established technology which is being successfully implemented in the Hangingstone and Leismer Projects.
- The regulatory application has been submitted for Dover West Sands Project 1.
- A pre-development plan is in place (for the full lifecycle) and FEED has been completed for Dover West Sands Project 1.
- The reservoir has been defined across the asset using delineation drilling as well as 2D and 3D seismic.
- Water source and disposal wells identified for Dover West Sands Project 1.

The negative factors relevant to the Contingent Resource estimates for Dover West Sands include:

- Economic sensitivity to future oil pricing.
- Minimal existing infrastructure.
- Uncertainty regarding regulatory regimes in Alberta.
- Ability to access project funding.
- Potential lack of pipeline capacity to access bitumen markets.
- Resource scarcity attributable to a number of other oil sands projects being developed in the area in the same timeframe.

See also "*Risk Factors*" in this Annual Information Form.

Abandonment and Reclamation Costs

The McDaniel Report included an estimate of the costs to abandon and reclaim all existing and future wells (not including pipelines and major dedicated facilities) associated with assessed Contingent Resources. No estimate of salvage value is netted against the estimated abandonment and reclamation costs. The estimate for abandonment and reclamation costs are based in part on the Company's estimation of costs to remediate, reclaim and abandon wells in which it has a working interest.

The future net revenues disclosed in this Annual Information Form are based on the Independent Report and contain an allowance for abandonment and reclamation costs for future development wells for Contingent Resources associated with the Leismer, Corner and Dover West Sand assets, however such amounts do not include an allowance for facilities or pipelines associated with such assets. The Independent Report includes an aggregate Best Estimate for abandonment and reclamation costs (escalated, unrisked, undiscounted) of $293 million at Leismer and $353 million at Corner, and $1,560 million at Dover West Sands.

APPENDIX B

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Report of Management and Directors on Reserves Data and Other Information

Management of Athabasca Oil Corporation (the "**Company**") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data and includes, if disclosed in the statement required by item 1 of section 2.1 of NI 51-101, other information such as contingent resources data. An independent qualified reserves evaluator has evaluated the Company's reserves data and contingent resources data. The reports of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

The Reserves Committee of the Board of Directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

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

(c) reviewed the reserves data and contingent resources data with management and the independent qualified reserves evaluator.

The Reserves 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 Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data, contingent resources data and other oil and gas information;

(b) the filing of Form 51-101F2 which is the report of the independent qualified reserves evaluator on the reserves data, contingent resources data, or prospective resources data; and

(c) the content and filing of this report.

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

(Signed) Robert Broen
Robert Broen
President & Chief Executive Officer

(Signed) Karla Ingoldsby
Karla Ingoldsby
Vice President, Thermal Oil

(Signed) Ronald J. Eckhardt
Ronald J. Eckhardt
Director

(Signed) Anne Downey
Anne Downey
Director

Dated March 4, 2020

APPENDIX C

FORM 51-101F2

REPORT ON RESERVES AND CONTINGENT RESOURCES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

Athabasca Oil Corporation
1200, 215 – 9th Avenue SW
Calgary, Alberta T2P 1K3

Attention: The Board of Directors of Athabasca Oil Corporation

Re: **Form 51-101F2**
Report on Reserves and Contingent Resources Data
by Independent Qualified Reserves Evaluator or Auditor
of Athabasca Oil Corporation (the "Company")

To the Board of Directors of Athabasca Oil Corporation (the "Company"):

1. We have evaluated the Company's reserves and contingent resources 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. The contingent resources data are risked estimates of volume of contingent resources and related risked net present value of future net revenue as at December 31, 2019, estimated using forecast prices and costs.

2. The reserves and contingent resources data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves and contingent resources data based on our evaluation.

3. We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook as amended from time to time (the "COGE Handbook") maintained by the Society of Petroleum Evaluation Engineers (Calgary Chapter).

4. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves and contingent resources data are free of material misstatement. An evaluation also includes assessing whether the reserves and contingent resources data are in accordance with 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 + probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2019, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

			Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)			
Independent Qualified Reserves Evaluator	**Effective Date of Evaluation Report**	**Location of Reserves**	**Audited**	**Evaluated**	**Reviewed**	**Total**
McDaniel	December 31, 2019	Canada	-	4,956,234	-	4,956,234

6. The following tables set forth the risked volume and risked net present value of future net revenue of contingent resources (before deduction of income taxes) attributed to contingent resources, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the Company's statement prepared in accordance with Form 51-101F1 and identifies the respective portions of the contingent resources data that we have evaluated and reported on to the Company's Board of Directors:

					Risked Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate)		
Classification	**Independent Qualified Reserves Evaluator**	**Effective Date of Evaluation Report**	**Location of Resources Other than Reserves**	**Risked Volume**	**Audited**	**Evaluated**	**Total**
					-	-	-
Development Pending Contingent Resources (2C)	McDaniel	December 31, 2019	Canada	734,634 Leismer and Corner	-	1,120,526	1,120,526

Classification	**Independent Qualified Reserves Evaluator**	**Effective Date of Evaluation Report**	**Location of Resources Other than Reserves**	**Risked Volume**
Economic Contingent Resources (project maturity sub-classes other than Development Pending)	McDaniel	December 31, 2019	Canada	1,346,303 Mbbl Dover West

7. In our opinion, the reserves and contingent resources data respectively evaluated 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 and contingent resources data that we reviewed but did not audit or evaluate.

8. We have no responsibility to update our report referred to in paragraphs 5 and 6 for events and circumstances occurring after the effective date of our report.

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

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

(Signed)

____

J. W. B. Wynveen, P. Eng.
Executive Vice President

Calgary, Alberta, Canada
March 3, 2020

APPENDIX D

AUDIT COMMITTEE MANDATE

The Audit Committee (**Committee**) of the board of directors **(Board)** of Athabasca Oil Corporation **(Company)** has the oversight responsibility and specific duties described below and shall comply with the requirements of applicable laws.

COMPOSITION

The Committee will be comprised of at least three directors or such greater number as the Board may determine from time to time. Except to the extent that the Board determines that an exemption contained in National Instrument 52-110 issued by the Canadian Securities Administrators or its successor instrument (**NI 52-110**) is available and determines to rely thereon, all Committee members will be independent within the meaning of NI 52-110.

All Committee members will be "financially literate" (as defined in NI 52-110) unless the Board determines that an exemption under NI 52-110 from such requirement in respect of any particular member is available and determines to rely thereon.

Committee members will be appointed and removed by the Board. The Committee Chair will be appointed by the Board.

RESPONSIBILITIES

The Committee's primary purpose is to assist the Board in fulfilling its oversight responsibilities with respect to: (i) the integrity of annual and quarterly financial statements to be provided to the Company's shareholders and regulatory bodies; (ii) compliance with accounting and finance based legal and regulatory requirements; (iii) the external auditor's qualifications, independence and compensation, and communicating with the external auditor; (iv) the system of internal accounting and financial reporting controls that management has established; (v) performance of the external audit process and of the external auditor; (vi) financial policies; (vii) financial risk management practices; and (viii) transactions or circumstances which could materially affect the financial profile of the Company.

Management of the Company is responsible for preparing the quarterly and annual financial statements of the Company and for maintaining a system of risk assessment and internal controls to provide reasonable assurance that assets are safeguarded and that transactions are authorized, recorded and reported properly. The Committee is responsible for reviewing management’s actions and has the authority to investigate any activity of the Company.

SPECIFIC DUTIES

The Committee will:

Audit Leadership

1. Have a clear understanding with the external auditor that it must maintain an open and transparent relationship with the Committee, and that the ultimate accountability of the external auditor is to the Committee, as representatives of the shareholders of the Company.

2. Provide an avenue for communication between each of the external auditor, financial and senior management and the Board. The Committee has the authority to communicate directly with the external auditors and financial and senior management.

Auditor Qualifications and Selection

3. Subject to required shareholder approval of the appointment of auditors of the Company, be solely responsible for recommending to the Board: (i) the external auditor for the purpose of preparing or issuing an auditor's report or performing other audit review or attest services for the Company; and (ii) the compensation of the external auditor. The Committee is directly responsible for overseeing the work of the external auditor, including the resolution of disagreements between management and the external auditor regarding financial reporting and reviewing, considering and making a recommendation to the Board regarding a proposed discharge of the external auditor when circumstances warrant. In all circumstances the external auditor reports directly to the Committee. The Committee is entitled to adequate funding to compensate the external auditor for completing an audit and audit report or performing other audit, review or attest services.

4. Evaluate the external auditor's qualifications, performance and independence. Take all reasonable steps to ensure that the external auditor does not provide non-audit services that would disqualify it as independent under applicable law.

5. Review the experience and qualifications of the senior members of the external audit team and the quality control procedures of the external auditor. Ensure that the lead audit partner of the external auditor is replaced periodically, according to applicable law. Take all reasonable steps to ensure continuing independence of the external audit firm. Present the Committee's conclusions on auditor independence to the Board.

6. Review and approve policies for the Company's hiring of senior employees and former employees of the external auditor who were engaged on the Company's account and make recommendations to the Board for consideration.

Process

7. Pre-approve all audit services (which may include consent and comfort letters in connection with securities offerings). Pre-approve and disclose, as required, the retention of the external auditor for non-audit services to be provided to the Company or any of its subsidiaries permitted under applicable law. In the discretion of the Committee, annually delegate to one or more of its independent members the authority to grant pre-approvals. Approve all audit fees and terms and all non-audit fees.

8. Meet with the external auditor prior to the audit to review the scope and general extent of the external auditor's annual audit including: (i) the planning and staffing of the audit; and (ii) an explanation from the external auditor of the factors considered in determining the audit scope, including the major risk factors.

9. Require the external auditor to provide a timely report setting out: (i) all critical accounting policies, significant accounting judgments and practices to be used; (ii) all alternative treatments of financial information within International Financial Reporting Standards (**IFRS**) that have been discussed with management, ramifications of the use of such alternative disclosures and treatments and the treatment preferred by the external auditor; and (iii) other material written communications between the external auditor and management.

10. Take all reasonable steps to ensure that officers and directors or persons acting under their direction are aware that they are prohibited from coercing, manipulating, misleading or fraudulently influencing the external auditor when the person knew or should have known that the action could result in rendering the financial statements materially misleading.

11. Upon completion of the annual audit, review the following with management and the external auditor:

(a) The annual financial statements, including related notes and the Management's Discussion and Analysis of Financial Condition and Results of Operations (**MD&A**) of the Company for filing with applicable securities regulators and provision to shareholders, as required, as well as all annual earnings press releases before their public disclosure.

(b) The significant estimates and judgements and reporting principles, practices and procedures applied by the Company in preparing its financial statements, including any newly adopted accounting policies and the reasons for their adoption.

(c) The results of the audit of the financial statements and whether any limitations were placed on the scope or nature of the audit procedures.

(d) Significant changes to the audit plan, if any, and any serious disputes or difficulties with management encountered during the audit, including any problems or disagreements with management which, if not satisfactorily resolved, would have caused the external auditor to issue a non-standard report on the financial statements of the Company.

(e) The cooperation received by the external auditor during its audit, including access to all requested records, data and information.

(f) Any other matters not described above that are required to be communicated by the independent auditor to the Committee.

Financial Statements and Disclosure

12. At least quarterly, as part of the review of the annual and quarterly financial statements, receive an oral report from the Company's counsel concerning legal and regulatory matters that may have a material impact on the financial statements.

13. Based on discussions with management and the external auditor, in the Committee's discretion, recommend to the Board whether the annual financial statements and MD&A of the Company, together with any annual earnings press releases should be approved for filing with applicable securities regulators and provision to the Company's shareholders, as required, prior to their disclosure.

14. Review the general types and presentation format of information that it is appropriate for the Company to disclose in earnings news releases or other earnings guidance provided to analysts and rating agencies.

15. Review with management and the external auditor the quarterly financial statements and MD&A and quarterly earnings releases prior to their release and recommend to the Board for consideration the quarterly results, financial statements, MD&A and news releases prior to filing them with or furnishing them to the applicable securities regulators and prior to any public announcement of financial results for the periods covered, including a written report of the results of the external auditor's reviews of the quarterly financial statements, significant adjustments, new accounting policies, any disagreements between the external auditor and management and the impact on the financial statements of significant events, transactions or changes in accounting principles or estimates that potentially affect the quality of financial reporting.

Internal Control Supervision

16. As required by applicable law, review with management and the external auditor the Company's internal controls over financial reporting, any significant deficiencies or material weaknesses in their design or operation, any proposed major changes to them and any fraud involving management or other employees who have a significant role in the Company's internal controls over financial reporting.

17. Review with management, the Chief Financial Officer and the external auditor the methods used to establish and monitor the Company's policies with respect to unethical or illegal activities by employees that may have a material impact on the financial statements.

18. Meet with management and the external auditor to discuss any relevant significant recommendations that the external auditor may have, particularly those characterized as "material" or "serious". Review responses of management to any significant recommendations from the external auditor and receive follow-up reports on action taken concerning the recommendations.

19. Review with management and the external auditor any correspondence with regulators or government agencies and any employee complaints or published reports which raise material issues regarding the Company's financial statements or accounting policies of the Company (as required).

20. Review with management and the external auditor any off-balance sheet financing mechanisms, transactions or obligations of the Company.

21. Review with management and the external auditor any material related party transactions.

22. Review with the external auditor the quality of the Company's accounting personnel. This review may occur without the presence of management. Review with management the responsiveness of the external auditor to the needs of the Company.

Disclosure Controls and Procedures

23. Periodically assess and be satisfied with the adequacy of procedures in place for the review of public disclosure of financial information extracted or derived from the applicable financial statements (other than the annual and quarterly required filings) for the Company.

Financial Management

24. Regularly review current and expected future compliance with covenants under all financing agreements.

25. Annually review the instruments the Company and its subsidiaries are permitted to use for short-term investments of excess cash and, in the Committee's discretion, make recommendations to the Board for consideration.

26. Review the Company’s compliance with required tax remittances and other deductions required by applicable law.

Financial Risk Management

27. Receive reports from management with respect to risk assessment, risk management and major financial risk exposures.

28. Discuss with management guidelines and policies with respect to financial risk assessment and financial risk management, including the processes management uses to assess and manage the Company's financial risk.

29. Annually review the insurance program including coverage for property damage, business interruption, liabilities, and directors and officers.

30. Review any other significant financial exposures of the Company to the risk of a material financial loss including tax audits or other activities.

31. Report to the Board on the financial risks of the Company and make recommendations to the Board for consideration.

32. Establish procedures (through approval of the relevant sections of the Code of Business Conduct) for: (i) the receipt, retention, and treatment of complaints received by the Company regarding accounting, internal accounting and financial reporting controls, or auditing matters; and (ii) the confidential, anonymous submission by employees of concerns regarding questionable accounting or auditing matters.

33. Once or more annually, as the Committee decides, review and assess the Company's Code of Business Conduct and, in the Committee's discretion, recommend any changes to the Board for consideration.

Committee Reporting

34. Following each meeting of the Committee, report to the Board on the activities, findings and any recommendations of the Committee.

35. Report regularly to the Board and review with the Board any issues that arise with respect to the quality or integrity of the financial statements of the Company, compliance with applicable law and the performance and independence of the external auditor of the Company.

36. Annually review and approve the information regarding the Committee required to be disclosed in the Company's Annual Information Form and Committee's report for inclusion in the annual Proxy Circular.

37. Prepare any reports required to be prepared by the Committee under applicable law.

Committee Meetings

38. Meet at least four times annually and as many additional times as needed to carry out its duties effectively. The Committee may, on occasion and in appropriate circumstances, hold meetings by telephone conference call.

39. Meet in separate, non-management, closed sessions with the external auditor at each regularly scheduled meeting.

40. Meet in separate, non-management, in camera sessions at each regularly scheduled meeting.

41. Meet in separate, non-management, closed sessions with any other internal personnel or outside advisors, as needed or appropriate.

42. A quorum for meetings of the Committee will be a majority of its members and the rules for calling, holding, conducting and adjourning meetings of the Committee will be the same as those governing the Board.

Committee Governance

43. Once or more annually, as the Compensation and Governance Committee (**CG Committee**) decides, receive for consideration that Committee's evaluation of this Mandate and any recommended changes. Review and assess the CG Committee's recommended changes and make recommendations to the Board for consideration.

Advisors/Resources

44. Have the sole authority to retain, oversee, compensate and terminate independent advisors to assist the Committee in its activities.

45. Receive adequate funding from the Company for independent advisors and ordinary administrative expenses that are needed or appropriate for the Committee to carry out its duties.

Other

46. With the CG Committee, the Board and the Board Chair, respond to potential conflict of interest situations, as required.

47. Carry out any other appropriate duties and responsibilities assigned by the Board.

48. To honour the spirit and intent of applicable law as it evolves, authority to make minor technical amendments to this Mandate is delegated to the Secretary, who will report any amendments to the CG Committee at its next meeting.

STANDARDS OF LIABILITY

Nothing contained in this Mandate is intended to expand applicable standards of liability under statutory, regulatory or other legal requirements for the Board or members of the Committee. The purposes and responsibilities outlined in this Mandate are meant to serve as guidelines rather than inflexible rules and, subject to applicable law and the articles and bylaws of the Company, the Committee may adopt such additional procedures and standards, as it deems necessary from time to time to fulfill its responsibilities.

Approved: December 11, 2009

Revised: March 14, 2012
May 11, 2015
July 26, 2017