ANNUAL INFORMATION FORM
DATED MARCH 20, 2020

NUVISTA ENERGY LTD

www.nuvistaenergy.com

WHO WE ARE

NuVista is an oil and natural gas company actively engaged in the exploration for, and the development and production of, oil and natural gas reserves in the Western Canadian Sedimentary Basin. Our primary focus is on the scalable and repeatable condensate-rich Montney formation in the Wapiti area of the Alberta Deep Basin.

We are publicly traded on the Toronto Stock Exchange (TSX: NVA). Find out more on our website *www.nuvistaenergy.com*, or contact us at investor.relations@nuvistaenergy.com.

WHAT'S INSIDE

SELECTED TERMS

Certain capitalized terms in this Annual Information Form have the meanings set forth below:

Entities

Board of Directors or Board means our board of directors.

NuVista, we, us, our or the **Corporation** means NuVista Energy Ltd.

Shareholders means holders of our Common Shares.

Reserves

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

CSA 51-324 means Staff Notice 51-324 – *Glossary to NI 51-101 Standards of Disclosure for Oil and Gas Activities* of the Canadian Securities Administrators.

GLJ means GLJ Petroleum Consultants Ltd., independent petroleum consultants of Calgary, Alberta.

GLJ Reserve Report means the report of GLJ dated February 6, 2020 evaluating as of December 31, 2019, our crude oil, natural gas and natural gas liquids reserves.

NI 51-101 means National Instrument 51-101– *Standards of Disclosure for Oil and Natural Gas Activities* of the Canadian Securities Administrators.

Securities

2021 Notes means our 9.875% senior unsecured notes which were redeemed in March of 2018 with the proceeds from the issuance of the 2023 Notes.

2023 Notes means our 6.50% senior unsecured notes due March 2, 2023.

Common Shares means our common shares.

Other

Credit Facility means our extendible revolving term credit facility available from a syndicate of Canadian chartered banks.

Credit Agreement the credit agreement with respect to our Credit Facility.

Wapiti Montney means the Montney formation in the Alberta Deep Basin.

CONVENTIONS

Certain terms used herein are defined in the "*Selected Terms*". Certain other terms used herein but not defined herein are defined in NI 51-101 and CSA 51-324 and, unless the context otherwise requires, shall have the same meanings herein as in NI 51-101 and CSA 51-324. Unless otherwise indicated, references herein to "$" or "dollars" are to Canadian dollars. All financial information herein has been presented in Canadian dollars in accordance with generally accepted accounting principles in Canada.

ABBREVIATIONS

Oil and Natural Gas Liquids		Natural Gas	
Bbl	barrel	Mcf	thousand cubic feet
Bbls	barrels	MMcf	million cubic feet
Bbls/d	barrels per day	Mcf/d	thousand cubic feet per day
Mbbls	thousand barrels	MMcf/d	million cubic feet per day
NGLs	natural gas liquids	MMbtu	million British Thermal Units
		GJ	gigajoule

Other	
AECO	The pricing point for gas transacted on TransCanada Pipeline's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
CGR	condensate-gas ratio
m^3	cubic metres
Mcfe	thousand cubic feet of gas equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one barrel of oil
MBoe	thousand barrels of oil equivalent
NYMEX	The New York Mercantile Exchange
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s	thousands of dollars

CONVERSIONS

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
Bbls	cubic metres	0.159
cubic metres	Bbls	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometers	1.609
kilometers	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
gigajoules	MMbtu	0.950
MMbtu	gigajoules	1.0526

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form, including documents incorporated by reference or referred to herein, contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to our future events or our future performance. All information and statements other than statements of historical fact contained in this Annual Information Form are forward-looking statements. Such forward-looking statements may be identified by looking for words such as "about", "approximately", "may", "believe", "expects", "will", "intends", "should", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "continues" or similar words or the negative thereof or other comparable terminology. In addition, there are forward-looking statements in this Annual Information Form under the headings: "*Oil and Gas Advisories – Drilling Locations*" as to the reclassification of contingent resources as reserves; "*NuVista Energy Ltd. – Summary Description of our Business*" and "*General Description of Our Business – Business Plan and Growth Strategies*" as to our business focus, plans and strategy; "*General Description of our Business – Asset and Business Strengths*" as to our current and future drilling inventory, our future development plans, the timing for the commencement of the Veresen Hythe gas plant, our commodity risk management program, our future exposure to AECO, our long term strategy with respect to acceptable debt levels, our growth potential, our environment, social and governance ("**ESG**") plans and the impact of the renegotiation or termination of contracts or subcontracts; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data*" as to our reserves and future net revenue from our reserves, income taxes, operating costs, abandonment and reclamation costs, pricing, exchange and inflation rates; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data*" as to the development of our proved undeveloped reserves and probable undeveloped reserves; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Significant Factors or Uncertainties*" as to the significant economic factors or significant uncertainties affecting our reserves data and our anticipated abandonment and reclamation costs and liability, drilling and completion plans, future developments costs, our ability to fund future developments costs through cash flow from operating activities and debt and equity issuances and anticipated funding costs; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information"* as to our capital expenditure plans, exploration and development activities, completion and processing plans, anticipated land expiries, hedging and marketing policies and plans, our future marketing plans, processing and transportation arrangements and plans, reclamation and abandonment obligations, plans relating to the satisfaction of our volume commitments, and our tax horizon; *"Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information"* as to our principal oil and natural gas properties; "*Dividends*" as to our dividend policy; "*Description of our Capital Structure – Credit Facility"* as to the anticipated renewal of our Credit Facility; *and "Legal Proceedings and Regulatory Actions"* as to the cost of remediation of a pipeline spill and our plans and expectations regarding these proceedings.

These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Forward-looking statements are based on the estimates and opinions of our management at the time the statements were made. In addition, forward-looking statements may include statements attributable to third party industry sources. There can be no assurance that the plans, intentions or expectations upon which such forward-looking statements are based will occur.

In addition to the forward-looking statements identified above, this Annual Information Form contains forward-looking statements pertaining to the following:

- the performance characteristics of our oil and natural gas properties;
- the future development potential of our assets;
- future well performance and related well economics;
- expectations of future production rates, volumes and product mixes;
- projected costs and plans and objectives;
- our capital expenditure program, the timing of expenditures and the sources of funding;
- our access to credit facilities, ability to raise capital and financial flexibility;
- our access to third-party infrastructure and ability to sell our products into various North American markets;
- future commodity prices;
- supply and demand for oil, natural gas and natural gas liquids;
- expected royalty rates and the anticipated benefits of royalty incentive programs;
  other matters referred to under the heading "*Industry Conditions*"; and
- our assessment of the impact of the various risks identified under the heading *"Risk Factors".*

Statements relating to "reserves" and "resources" are also deemed to be forward-looking 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 or resources can be profitably produced in the future.

Forward-looking statements are subject to risks, uncertainties and assumptions, including those discussed below and elsewhere in this Annual Information Form. Although we believe that the expectations represented in such forward-looking statements are reasonable, there can be no assurance that such expectations will prove to be correct. Some of the risks which could affect future results and could cause results to differ materially from those expressed in the forward-looking statements contained herein include the following:

- the impact of the COVID-19 crisis;
- volatility of commodity prices and differentials;
- weakness and volatility in the oil and natural gas industry;
- lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines;
- volatility of commodity prices and differentials;
- weakness and volatility in the oil and natural gas industry;
- political uncertainty;
- liabilities inherent in oil and natural gas operations;
- stock market volatility;
- incorrect assessments of the value of acquisitions;
- operational dependence on third parties;
- project risks;
- environmental risks;
- increased governmental regulation and regulatory changes;
- increased costs related to environmental regulation compliance;
- the inability to access sufficient capital from internal and external sources and the cost of capital;
- imprecision of reserve and resource estimates;
- changes in our credit ratings;
- competition from other industry participants;
- risks associated with our information technology systems, social media and cyber-security;

- our ability to successfully implement new technologies into our operations;
- alternatives to and changing demand for petroleum products;
- negative public opinion and reputational risk associated with our operations;
- changing investor sentiment;
- geological, technical, drilling and processing problems;
- applicable royalty rates and tax laws;
- climate change regulation and carbon pricing;
- liability management programs;
- fluctuation in foreign exchange or interest rates;
- risks associated with refinancing our Credit Facility and our level of indebtedness;
- risks associated with our hedging activities;
- the lack of availability of qualified personnel or management or oilfield services;
- unforeseen title claims or defects;
- geopolitical risks;
- non-governmental organizations;
- Indigenous claims;
- unforeseen litigation;
- our ability to satisfy our obligations under our firm commitment transportation and processing arrangements;
- general economic and industry conditions; and
- the other factors discussed under "*Risk Factors*".

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding, among other things: the timing of obtaining regulatory approvals; commodity prices and royalty regimes; availability of skilled labour; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; access to capital; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates and future operating costs. We have included the above summary of assumptions and risks related to forward-looking statements provided in this Annual Information Form in order to provide investors with a more complete perspective on our current and future operations and such information may not be appropriate for other purposes.

You are further cautioned that the preparation of financial statements requires management to make certain judgments and estimates that affect the reported amounts of assets, liabilities, revenues and expenses. Estimating reserves and resources is also critical to several accounting estimates and requires judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change, having either a negative or positive effect on net earnings as further information becomes available, and as the economic environment changes. **The information contained in this Annual Information Form, including the documents incorporated by reference or referred to herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

The forward-looking statements contained herein are expressly qualified in their entirety by this cautionary statement. The forward-looking statements included in this Annual Information Form are made as of the date of this Annual Information Form and we undertake no obligation to publicly update such forward-looking statements to reflect new information, subsequent events or otherwise unless required by applicable securities laws.

OIL AND GAS ADVISORIES

Oil and Gas Metrics

We have adopted the standard of 6 Mcf:1 Bbl when converting natural gas to oil equivalent and 1 Bbl:6 Mcf when converting oil to natural gas equivalent. 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. **Given that the value ratio based on the current price of crude oil as compared to natural gas 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.**

Drilling Locations

This Annual Information Form discloses our drilling locations in two categories: (i) undeveloped proved plus probable drilling locations; and (ii) undeveloped best estimate contingent drilling locations. Undeveloped proved plus probable drilling locations are derived from the GLJ Reserve Report and account for undeveloped drilling locations that have associated proved and/or probable reserves, as applicable. Undeveloped best estimate contingent drilling locations are derived from a report prepared by GLJ evaluating our contingent resources as of December 31, 2019 (the "**GLJ Contingent Resource Report**").

There is no certainty that we will drill all drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. 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. In the case of the contingent resources estimated in the GLJ Contingent Resource Report, contingencies include: (i) further delineation of interest lands; (ii) corporate commitment, and; (iii) final development plan. To further delineate interest lands additional wells must be drilled and tested to demonstrate commercial rates on the resource lands. Reserves are only assigned in close proximity to demonstrated productivity. As continued delineation drilling occurs, a portion of the contingent resources are expected to be reclassified as reserves. Confirmation of corporate intent to proceed with remaining capital expenditures within a reasonable timeframe is a requirement for the assessment of reserves. Finalization of a development plan including timing, infrastructure spending and the commitment of capital. Determination of productivity levels is generally required before the company can prepare firm development plans and commit required capital for the development of the contingent resources. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.

NON-GAAP MEASURES

The term "netback" in this Annual Information Form is not a recognized measure under generally accepted accounting principles ("**GAAP**"). We use "netback" as a key performance indicator and it is used by us to evaluate the operating performance of our petroleum and natural gas assets. Netbacks are calculated by subtracting royalties, production costs and transportation from revenues.

We use the term "net debt to annualized current quarter" in this Annual Information Form which is not a recognized measure under GAAP. We calculate adjusted funds flow based on cash flow provided by operating activities, excluding changes in non-cash working capital, asset retirement expenditures and environmental remediation recovery. Net debt is based on cash and cash equivalents, accounts receivable and prepaid expenses, accounts payable and accrued liabilities, long term debt (credit facility) and senior unsecured notes. See our management's discussion and analysis for the year ended December 31, 2019 for further information on how we calculate these measures, a discussion of why management has deemed the measure to be useful and a reconciliation to the most comparable GAAP measure.

Readers are cautioned that these measure should not be construed as an alternative to net earnings or funds from operating activities determined in accordance with GAAP as an indication of our performance.

NUVISTA ENERGY LTD.

Summary Description of our Business

We are an independent oil and natural gas company engaged in the exploration for, and the development, production and acquisition of oil and natural gas reserves in the province of Alberta. Our primary focus is on the scalable and repeatable condensate-rich Montney formation in the Wapiti Montney. See "*General Development of Our Business*", "*General Description of Our Business*" and "*Statement of Reserves Data and Other Oil and Natural Gas Information*" in this Annual Information Form.

We were incorporated under the *Business Corporations Act* (Alberta) as 1040491 Alberta Ltd. on April 7, 2003. On May 20, 2003, we changed our name to "NuVista Energy Ltd." and on June 24, 2003, we amended our Articles to create our performance shares and remove our private company restrictions.

On January 1, 2009, we amalgamated with Rider Resources Ltd. and immediately thereafter amalgamated with Roberts Bay Resources Ltd., a wholly-owned subsidiary.

On September 30, 2014, we completed an internal corporate restructuring, which through a series of transactions resulted in the dissolution of our three partnerships and the amalgamation of our three subsidiaries. We have no material subsidiaries and are not partner to any partnerships.

On May 12, 2015, we filed Articles of Amendment to remove the performance shares from our share capital.

Our head office is located at Suite 2500, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1 and our registered office is located at Suite 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

On July 2, 2003, we completed a plan of arrangement with Bonavista Petroleum Ltd. pursuant to which we acquired certain assets of Bonavista Petroleum Ltd. and our Common Shares were distributed to the former holders of common shares of Bonavista Petroleum Ltd. We then grew our business through a combination of exploration, acquisition, and development of our assets. In 2010-2012 we evaluated several resource plays on our lands for development potential, and ultimately selected the Montney zone in the Wapiti area as the pre-eminent play which had the strongest economics and massive scale to take our company to the next level. All other assets were then progressively deemed non-core and were divested in stages, in order to provide the proceeds towards the launch of our Montney condensate-rich resource play development. For a number of years now we have been a pure-play company focused almost solely upon the Montney at Wapiti near the town of Grande Prairie, Alberta.

The following provides a summary of how our business has developed over the last three years.

Asset Dispositions

We disposed of various non-core assets throughout 2017 for aggregate gross proceeds of $2.2 million. Total average production associated with these assets was approximately 370 Boe/d which included approximately 23 Bbls/d of condensate and oil, approximately 19 Bbls/d of NGLs (excluding condensate), and approximately 1,970 Mcf/d of conventional natural gas.

We did not complete any producing property dispositions in 2018 or 2019.

Asset Acquisitions

On September 6, 2018, we completed the acquisition of Cenovus Pipestone ULC and Cenovus Pipestone Partnership (the "**Pipestone Acquisition**") which held assets in the Pipestone area of Northwest Alberta (the "**Acquired Assets**") for $619.4 million including customary adjustments. Subsequently, all of the Acquired Assets were assumed by NuVista and the partnership and ULC were dissolved. The Acquired Assets are situated primarily in the condensate rich Alberta Triassic Montney fairway on 35,250 net acres of land featuring four layers of Montney development, and represented a 29% increase to our Montney land position, adding approximately 9,600 Boe/d of production and significant infrastructure. The production included approximately 2,200 Bbls/d of condensate and oil, approximately 2,200 Bbls/d of NGLs (excluding condensate), and approximately 31,100 Mcf/d of conventional natural gas. The Pipestone Acquisition was funded with our expanded Credit Facility and the issuance of 47.4 million subscription receipts at a price of $8.10 per subscription receipt for gross proceeds of $384.1 million.

We did not complete any property acquisitions 2019.

Equity Offerings

On October 28, 2016, we completed a public offering with a syndicate of underwriters of an aggregate of 15,111,000 Common Shares at $6.85 per share for gross proceeds of $103.5 million, which included 1,971,000 Common Shares issued pursuant to the full exercise of the over-allotment option granted to the underwriters.

In August 2018, as part of the financing of the Pipestone Acquisition, we issued 47.4 million subscription receipts at a price of $8.10 per subscription receipt, for gross proceeds of $384.1 million. Of these, 21.0 million subscription receipts were issued pursuant to a public offering, and an additional 26.4 million subscription receipts were issued pursuant to a private placement. The subscription receipts were converted into an equal number of Common Shares in accordance with their terms upon completion of the Pipestone Acquisition. We also issued 2.8 million Common Shares on a flow-through basis in respect of Canadian development expenses at a price of $9.05 per Common Share for gross proceeds of $24.9 million, of which 0.4 million Common Shares were issued pursuant to a private placement to certain directors, officers and employees on a non-brokered basis. At December 31, 2018, we had fulfilled our commitment to spend $24.9 million on qualifying Canadian development expenses.

Senior Unsecured Notes

On March 2, 2018, we issued $220.0 million aggregate principal amount of 2023 Notes. Part of the proceeds from the 2023 Notes were used to redeem all of the 2021 Notes. The full aggregate principal amount of the 2021 Notes of $70.0 million was redeemed plus an agreed redemption premium of $6.6 million. The remaining proceeds from the 2023 Notes were used to reduce bank indebtedness.

Credit Facility

On June 13, 2016, we completed the annual redetermination of our borrowing base with our lenders. After adjustments to account for the issuance of the 2021 Notes as well as the divestiture of W6 Sweet Cretaceous assets, our borrowing base was set at $200 million effective June 22, 2016.

On April 27, 2017, we completed the annual redetermination of our borrowing base with our lenders and our borrowing base increased to $235 million effective April 27, 2017.

On October 27, 2017, we completed the semi-annual redetermination of our borrowing base with our lenders. As a result of strong well results, our borrowing base was set at $310 million effective October 27, 2017.

On December 21, 2017, our lenders amended the Credit Agreement to modify our ability to enter into basis swap hedges.

On August 24, 2018, the maximum volume limit for the basis swap hedges was increased.

On March 2, 2018, our lenders amended the Credit Agreement to account for the issuance of the 2023 Notes and the redemption of the 2021 Notes.

On April 26, 2018, we amended the Credit Agreement to modify the pricing grid.

On September 6, 2018 our lenders increased the Credit Facility to $450 million from the prior $310 million upon closing of the Pipestone Acquisition.

On April 22, 2019, our lenders amended the Credit Agreement to permit the sale of certain lands for the construction of the Pipestone South Compressor Station.

On April 30, 2019 we completed the annual review of our borrowing base and our lenders increased the Credit Facility from $450 million to $500 million.

On November 28, 2019, we completed the semi-annual redetermination of the borrowing base of our Credit Facility with our lenders. As a result of strong well results, our borrowing base was increased to $550 million. In addition, the tenor of our Credit Facility was converted from a one year revolving facility with a one year term-out period into a two year revolving facility, maturing on April 30, 2021.

Management and Board of Directors

On December 6, 2017, Mr. Mike Lawford, formerly Vice President, Development was appointed to Chief Operating Officer and Mr. Ryan Paulgaard was appointed our Vice President, Production and Facilities. Mr. Chris McDavid, formerly Vice President of Operations was appointed Vice President of Development and Engineering.

On September 13, 2018, Mr. Chris McDavid left NuVista to pursue other opportunities.

In May, 2019, Mr. Chris LeGrow, formerly Manager, Planning & Corporate Development was appointed to Vice President, Development and Planning.

GENERAL DESCRIPTION OF OUR BUSINESS

Business Plan and Growth Strategies

Our primary focus is the development and delineation of our primary operating area, the Wapiti Montney. The Wapiti Montney is a condensate-rich natural gas resource play that provides us with significant profitable growth potential into the future. We continue to employ a disciplined approach to our business plan that focuses on strong economics and rapid payback periods to provide positive near and long-term operating and financial returns.

We apply our technical and operating expertise within the Montney area with a disciplined approach based on the following principles:

- Long term full cycle returns and shareholder value growth;
- focus - establish technical expertise in key areas;
- invest in plays with scalability and repeatability, and strong economics;
- operate our production and hold a high working interest;
- think beyond the wellhead – optimize product pricing and reduce volatility through a combination of long term hedging and egress strategies;
- create a culture of capital discipline, strong execution, and performance;
- attract and retain a talented team;
- control our business plan and be opportunity driven;
- maintain financial flexibility; and
- health, safety and environment – focus on safe operations, minimization of our environmental impact and support of the communities in which we operate.

We have created an organization in which operational and technical excellence and idea generation are encouraged in a culture that emphasizes accountability and performance. By focusing in one primary operating area, our teams enhance their ability to identify opportunities and improve economics. Our goal is also to operate with a high working-interest ownership. This enables us to control the pace of development, minimize costs and cycle times, and allows us to accurately forecast the timing and magnitude of our efforts.

We continue to enforce stringent cost controls to maintain our financial flexibility throughout the commodity price cycles. We believe that stewardship of our capital spending over the long-term is the single biggest factor in our ability to grow profitably.

In the period of 2011 to 2013, we successfully transitioned from a junior exploration and production company with a focus on shallow natural gas in eastern Alberta to a company with a focus on our longer-life condensate-rich natural gas Wapiti Montney play with significant scale, repeatability and upside. The Wapiti Montney now represents approximately 96% of our total production and substantially 100% of our budgeted capital expenditures.

Asset and Business Strengths

We believe that we have the following key asset and business strengths:

Condensate-Rich Montney Assets

We have established an extensive land position in the condensate-rich Montney located south of Grande Prairie, Alberta. We hold rights in approximately 255 gross sections (228 net) of land with an approximate working interest of 90%. Currently, over 99% of our production is located in the greater Wapiti area. We have an inventory of approximately 1,165 gross drilling locations (376 undeveloped proved and probable drilling locations and 789 undeveloped best estimate contingent drilling locations), which includes Montney intervals with current production or with direct offset production. Based on our current drilling pace, this provides for approximately 40 plus years of drilling. In addition, we expect this inventory count to increase as additional zones are tested and economically brought on production. See "*Oil and Gas Advisories – Drilling Locations*".

Our Wapiti Montney assets have a CGR that ranges from approximately 20 Bbl/MMcf to over 200 Bbl/MMcf with most wells in the 50 to 150 range. This high CGR enables our production mix to average approximately 28% to 32% condensate in Boe terms. As a result, our condensate revenue comprised approximately 63% of our total petroleum and gas revenues in 2019. Condensate volumes are used primarily as a diluent for oilsands production and as a result, have historically traded at par or a slight premium to WTI prices.

We previously produced from three main areas of the Wapiti Montney – Bilbo, Elmworth and Gold Creek - and in 2018 kicked off the Pipestone South development and also completed a major acquisition at Pipestone North with the purchase of the Acquired Assets.

Additionally, through a combination of the Pipestone Acquisition in 2018, and other minor transactions, we have put together a meaningful land position of approximately 172 gross sections (119 net), with an approximate working interest of 69%, in the emerging Charlie Lake light oil play in the greater Pipestone area. We have drilled two horizontal wells to date and have booked an additional 22 gross proved plus probable undeveloped locations and 225 gross additional locations booked as contingent resources.

Operational Excellence

We have a strong record of operational performance. We have achieved a 100% drilling success rate in the Montney area over the last five years. During this time, we have continually improved the well design of our Montney wells. In particular, we have increased the horizontal length of our laterals and we continue to test increased frac intensity levels. Our original horizontal wells had lateral lengths of approximately 1,500 metres and contained 15 frac stages. Today, our wells laterals are often 3,000 metres and have been up to 5,000 metres in length and can contain over 80 frac stages. These enhancements have dramatically improved well performance and related well economics while reducing capital costs per stage or per metre of rock accessed. The time to drill these wells has also been reduced dramatically from an average of over 37 days in 2013 to less than 18 days in 2019.

Strong Market Access and Egress

We have firm transportation egress and processing agreements in place to support our growth plan. Currently, the majority of our production flows through two 100% owned and operated compressor stations and one operated compressor that a third party owns. The compressor station located in our Bilbo block has productive capacity of approximately 18,000 Boe/d while our Elmworth area compressor stations have a capacity of approximately 19,000 Boe/d and the third party compressor station on our Pipestone South block has a capacity of approximately 12,000 Boe/d.

The vast majority of our production is processed through three large sour gas plants, Keyera Simonette, SemCAMS K3 and SemCAMS Wapiti. Our existing Wembley and Pipestone North volumes flow through the NuVista Wembley gas plant. As part of the Pipestone Acquisition, we acquired a 39% operating working interest in this gas plant which has been operating at capacity. To accommodate planned future growth, we have contracted for capacity in the Veresen Hythe gas plant which is scheduled to commence in late 2020.

See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Marketing Arrangements*" and "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Processing and Transportation*".

In addition to securing processing agreements, we have contracted for firm pipeline transportation capacity to ensure our natural gas, condensate and natural gas liquids reach market. We have also contracted for long term and/or renewable export pipeline capacity on the Alliance Pipeline to Chicago, the Foothills/GTN system to Malin, Oregon and the TCPL Mainline system to Dawn. This approach has allowed us to reach various North American markets for our natural gas allowing for diversified and enhanced natural gas pricing versus AECO pricing in the past few years.

We have a disciplined commodity price risk management program as part of our financial risk management strategy. The purpose of this program is to reduce volatility in financial results and help stabilize cash flow from operating activities against the unpredictable commodity price environment. Our Board of Directors has authorized the use of fixed price, put option and costless collar contracts ("**Fixed Price Contracts**"), and has approved the terms of our commodity price risk management program to allow the securing of minimum prices of the following:

(% of net forecast after royalty production)	First 18 month forward period	Following 18 month forward period	Following 24 month forward period
Natural Gas Fixed Price Contracts	up to 70%	up to 60%	up to 50%
Crude Oil Fixed Price Contracts	up to 70%	up to 60%	up to 30%

In addition, our Board of Directors has set limits for entering into natural gas basis differential contracts that are the lesser of 50% of forecast natural gas production, net of royalties, or the volumes that would bring the combined natural gas basis differential contracts and natural gas fixed price contracts to 100% of forecast natural gas production, net of royalties. In addition, a maximum volume of up to 150,000 MMbtu/day has been approved, with a term of 7 years from the date any such swap is entered into. Hedges on crude oil, natural gas liquids, natural gas, differentials and basis may be made in Canadian or U.S. dollars at the time the position is established and the position may be hedged to Canadian or U.S. dollars, as the case may be, during the term of the applicable hedge. Foreign currency of interest payments and of long-term debt, if there is that exposure, may also be hedged back to the Canadian dollar.

Our existing contracts for firm transportation on export pipelines coupled with the financial NYMEX basis natural gas sales price derivative contracts will result in long term price diversification and exposure to AECO floating pricing limited to approximately 10% to 25% of volumes in 2020 and beyond.

Solid Balance Sheet and Liquidity Position

Our long term strategy is to maintain a net debt to annualized current quarter adjusted funds flow ratio of less than 1.5x. However, in periods of volatile and lower commodity prices, we are willing to work to target a net debt to annualized current quarter adjusted funds flow ratio of around 2x. See "*Non-GAAP Measures*".

Management believes our diversified marketing portfolio and risk management program provides protection against commodity price volatility and supports the funding of our capital program. Historically, we have demonstrated our commitment to maintaining a strong liquidity position through active management of capital expenditures, strategic financings and timely asset dispositions.

Experienced Management Team

We have a highly experienced and respected management team with extensive knowledge of the sector and a successful track record of predictably building scale through the development and exploitation of assets in the western Canadian sedimentary basin.

Cyclical and Seasonal Impact of Industry

Our operational results and financial condition are dependent on the prices we receive for condensate, oil, natural gas liquids and natural gas production. Oil, condensate, natural gas liquids and natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors, including weather and general economic conditions, as well as conditions in other oil and natural gas regions. Any decline in condensate, oil, natural gas liquids and natural gas prices could have an adverse effect on our financial condition. We mitigate such price risk through closely monitoring the various commodity markets and establishing price risk management programs, as deemed necessary and through maintaining financial flexibility as well as capital spending flexibility. See "*Risk Factors – Prices, Markets and Marketing*" and "*Risk Factors – Hedging*".

Environment Policies

We are committed to managing and operating in a safe, efficient, environmentally responsible manner in association with our industry partners and are committed to continually improving our environmental, health, safety and social performance. To fulfill this commitment, our operating practices and procedures are consistent with the extensive requirements and regulations established for the Canadian and Alberta oil and gas industry. We also support and endorse the Environmental Operating Procedures developed by the Canadian Association of Petroleum Producers. Key environmental considerations include air quality and climate change, water conservation, spill management, waste management plans, hydraulic fracturing, lease and right-of-way management, natural and historic resource protection, and liability management (including site assessment and remediation). These practices and procedures apply to our employees and we monitor all activities and make reasonable efforts to ensure that companies who provide services to us will operate in a manner consistent with our environmental policy.

We believe that we meet all existing environmental standards and regulations and include sufficient amounts in our capital expenditure budget to continue to meet current environmental protection requirements. These requirements apply to all operators in the oil and gas industry; therefore it is not anticipated that our competitive position within the industry will be adversely affected by changes in applicable legislation. We have internal procedures designed to ensure that detailed due diligence reviews to assess environmental liabilities and regulatory compliance are completed prior to proceeding with new acquisitions and developments.

Our environmental management plan and operating guidelines focus on minimizing the environmental impact of our operations while meeting regulatory requirements and corporate standards. Our environmental program includes: an internal environmental compliance audit and inspection program; a suspended well inspection program to support future development or eventual abandonment; appropriate reclamation and decommissioning standards for wells and facilities ready for abandonment; an effective surface reclamation program; a groundwater monitoring program; a spill prevention, response, and clean-up program; a methane and fugitive emission survey and repair program, and an environmental liability assessment program.

We expect to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2019, expenditures for abandonment and reclamation costs, including costs to reclaim and abandon ownership interests in oil and natural gas assets including well sites, and gathering systems and processing facilities totaled $14.4 million. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Significant Factors or Uncertainties – Additional Information Concerning Abandonment and Reclamation Costs*".

We participate in both the Canadian federal and provincial regulated greenhouse gas emissions reporting programs and continue to quantify annual greenhouse gas emissions for internal reporting purposes. In recent years we have made great strides in reducing our production CO_2 intensity to minimize our impact on global climate change and to minimize exposure to potential future carbon taxation.

We remain focused on creating, enhancing and delivering value to our stakeholders. One way we seek to protect value is by better understanding, disclosing and managing our environmental and social impacts. In recognition of the importance of clear board oversight and risk management for ESG matters, we have established a separate ESG committee of our board.

We are also proud to have demonstrated our commitment to transparency and ethical practices in our inaugural ESG report prepared earlier in 2019. This report, available for viewing on our website, provides a comprehensive look at our ESG practices while highlighting the proactivity and excellent execution our teams have always demonstrated in advancement of our ESG performance. Key highlights of the report include our high safety and environmental performance, our long term progress in reducing greenhouse gas ("**GHG**") intensity, and our strong governance and community focus. Approximately 70% of our current production is comprised of natural gas which has the lowest carbon footprint of any hydrocarbon, leading to our greenhouse gas emissions performance being well below the North American benchmark and we continue to execute projects to enhance our ESG progress.

Renegotiation or Termination of Contracts

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

Competitive Conditions

We are a member of the petroleum industry, which is highly competitive at all levels. We compete with other companies for all of our business inputs, including exploration and development prospects, access to commodity markets, acquisition opportunities, available capital and staffing. See "*Risk Factors – Competition*".

We strive to be competitive by maintaining financial flexibility and by utilizing current technologies to enhance optimization, development and operational activities.

Human Resources

At December 31, 2019, we employed 88 full-time employees, including 70 office and 18 field employees.

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below is dated February 6, 2020. The statement is effective as of December 31, 2019 and the preparation date of the statement is February 4, 2020. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

Disclosure of Reserves Data

The reserves data set forth below is based upon an evaluation by GLJ with an effective date of December 31, 2019, as contained in the GLJ Reserve Report. The reserves data summarizes our crude oil, natural gas liquids and natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs, not including the impact of any price risk management activities. The GLJ Reserve Report has been prepared in accordance with the standards contained in the COGE Handbook and the reserve definitions contained in NI 51-101 and CSA 51-324. We engaged GLJ to provide an evaluation of our proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of our reserves are in Canada and, specifically, in the Province of Alberta.

We determined the future net revenue and present value of future net revenue after income taxes by utilizing GLJ's before income tax future net revenue and our estimate of income tax. Our estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of our tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after-tax valuation. The after-tax net present value of our oil and gas properties reflects the tax burden of our properties on a stand-alone basis. It does not provide an estimate of the value of us as a business entity, which may be significantly different. Our financial statements for the year ended December 31, 2019 and the associated management's discussion and analysis should be consulted for additional information regarding our taxes.

Future net revenue is a forecast of revenue, estimated using forecast 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. The estimated future net revenue contained in the following tables does not necessarily represent the fair market value of our reserves. There is no assurance that the forecast price and cost assumptions contained in the GLJ Reserve Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized in the notes to or following the tables below. Readers should review the definitions and information contained in "*Definitions and Notes to Reserves Data Tables*" below in conjunction with the following tables and notes. **The recovery and reserve estimates on our properties described herein are estimates only. The actual reserves on our properties may be greater or less than those calculated.** See "*Risk Factors*".

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE AS OF DECEMBER 31, 2019 FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS (1)		NATURAL GAS LIQUIDS		SHALE GAS	
RESERVES CATEGORY	GROSS (Mbbls)	NET (Mbbls)	GROSS (MMcf)	NET (MMcf)	GROSS (Mbbls)	NET (Mbbls)	GROSS (MMcf)	NET (MMcf)
PROVED:								
Developed Producing	669	546	11,544	10,471	33,511	26,422	352,535	328,146
Developed Non-Producing	279	252	2,863	2,619	5,025	4,070	56,512	52,275
Undeveloped	2,072	1,755	10,232	9,336	79,644	65,636	959,739	888,074
TOTAL PROVED	3,021	2,552	24,639	22,426	118,180	96,129	1,368,786	1,268,495
TOTAL PROBABLE	3,066	2,495	14,571	13,397	77,227	59,386	945,538	863,831
TOTAL PROVED PLUS PROBABLE	6,087	5,047	39,210	35,824	195,407	155,515	2,314,324	2,132,326

Note:
(1) Includes solution gas and an immaterial amount of coal bed methane.

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR)					UNIT VALUE BEFORE INCOME TAXES DISCOUNTED AT 10% (1)	
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)	($/Boe)	($/Mcfe)
PROVED:							
Developed Producing	1,292,957	1,074,708	894,066	766,667	675,143	10.72	1.79
Developed Non-Producing	235,812	171,698	134,355	110,644	94,428	9.97	1.66
Undeveloped	3,024,261	1,743,436	1,081,329	705,077	473,909	4.98	0.83
TOTAL PROVED	4,553,030	2,989,842	2,109,750	1,582,388	1,243,480	6.72	1.12
TOTAL PROBABLE	3,995,971	1,895,163	1,070,610	684,758	477,200	5.15	0.86
TOTAL PROVED PLUS PROBABLE	8,549,000	4,885,004	3,180,360	2,267,147	1,720,679	6.09	1.02

Note:
(1) Unit values are based on net reserve volumes.

RESERVES CATEGORY	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year) 0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	1,292,957	1,074,708	894,066	766,667	675,143
Developed Non-Producing	233,639	170,918	134,061	110,529	94,380
Undeveloped	2,327,184	1,342,900	828,276	533,742	351,855
TOTAL PROVED	3,853,780	2,588,526	1,856,403	1,410,938	1,121,378
TOTAL PROBABLE	3,074,721	1,446,031	806,498	509,619	351,900
TOTAL PROVED PLUS PROBABLE	6,928,501	4,034,557	2,662,901	1,920,556	1,473,277

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2019 FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE ($000s) [1]	ROYALTIES ($000s) [2]	OPERATING COSTS ($000s)	DEVELOP-MENT COSTS ($000s)	ABANDON-MENT AND RECLAMATION COSTS ($000s) [3]	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
TOTAL PROVED	13,971,424	1,642,105	5,475,411	2,022,335	278,545	4,553,030	699,250	3,853,780
TOTAL PROVED PLUS PROBABLE	25,085,139	3,237,338	9,847,373	3,108,211	343,217	8,549,000	1,620,499	6,928,501

Notes:

(1) Total revenue includes company revenue before royalty and includes other income.

(2) Royalties include Crown, freehold and overriding royalties and mineral tax.

(3) The GLJ abandonment and reclamation costs estimates are based on the Alberta Energy Regulator's Directive 011 - Licensee Liability Rating (LLR) Program: Updated Industry Parameters and Liability Costs. These are estimated abandonment and reclamation of all of our existing and future wells, facilities and pipelines. These include all active and inactive entities within active and inactive assets.

FUTURE NET REVENUE BY PRODUCT TYPE AS OF DECEMBER 31, 2019 FORECAST PRICES AND COSTS			
PRODUCT TYPE [1]	NET PRESENT VALUE OF FUTURE NET REVENUE [3][4] (before deducting Future Income Tax Expenses and Discounted at 10%/year) ($000s)	UNIT VALUE [2] [5] (before deducting Future Income Tax Expenses and Discounted at 10%/year) ($/Boe)	 ($/Mcfe)
PROVED:			
Light and Medium Crude Oil [1]	53,369	9.76	1.63
Heavy Oil [1]	69	49.29	8.22
Conventional Natural Gas [2]	12,934	5.43	0.90
Shale Gas [2]	2,043,377	6.68	1.11
TOTAL PROVED	2,109,750	6.72	1.12
PROVED PLUS PROBABLE			
Light and Medium Crude Oil [1]	117,137	10.90	1.82
Heavy Oil [1]	80	48.15	8.02
Conventional Natural Gas [2]	16,111	5.32	0.89
Shale Gas [2]	3,047,032	6.00	1.00
TOTAL PROVED PLUS PROBABLE	3,180,360	6.09	1.02

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products and an immaterial amount of coal bed methane but excluding solution gas.
(3) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups.
(4) Columns may not add due to rounding.
(5) Unit values are based on net reserve volumes.

Definitions and Notes to Reserves Data Tables

In the tables set forth in this "*Statement of Reserves Data and Other Oil and Natural Gas Information*" section and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "**gross**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share before deduction of royalties and without including any of our royalty interests;

   (b) in relation to wells, the total number of wells in which we have an interest; and

   (c) in relation to properties, the total area of properties in which we have an interest.

2. "**net**" means:

   (a) in relation to our interest in production and reserves, our interest (operating and non-operating) share after deduction of royalty obligations, plus our royalty interest in production or reserves;

   (b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and

(c) in relation to our interest in a property, the total area in which we have an interest multiplied by our working interest.

3. Definitions used for reserve categories are as follows:

Reserve Categories

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

(a) analysis of drilling, geological, geophysical and engineering data;

(b) the use of established technology; and

(c) specified economic conditions (see the discussion of "Economic Assumptions" below).

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

(a) 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.

(b) 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 plus probable reserves.

4. "**economic assumptions**" are the forecast prices and costs used in the estimate:

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) 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:

(i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open 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; and

(ii) 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.

(b) 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, probable) 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 reserve 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 are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative 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 will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

5. "**unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

6. "**exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

7. "**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

   (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

   (b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

   (c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

   (d) provide improved recovery systems.

8. "**development well**" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

9. "**exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

   (a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

10. "**service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or fuel gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

11. "**forecast prices and costs**"

These are prices and costs that are:

(a) generally acceptable as being a reasonable outlook of the future; and

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are 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 paragraph (a).

12. Numbers may not add due to rounding.

13. The estimates of future net revenue presented in the tables above do not represent fair market value.

14. We do not have any synthetic oil.

Pricing Assumptions

The forecast cost and price assumptions in this Annual Information Form assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Crude oil, natural gas and NGL benchmark reference pricing, inflation and exchange rates utilized in the GLJ Reserve Report were as follows**:**

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
FORECAST PRICES AND COSTS (1)(2)

YEAR	OIL				NATURAL GAS		NATURAL GAS LIQUIDS					
	WTI Cushing Oklahoma ($US/Bbl)	**Edmonton Par Price 40° API** ($Cdn/Bbl)	**Hardisty Heavy 12° API** ($Cdn/Bbl)	**Cromer Medium 29° API** ($Cdn/Bbl)	**AECO Natural Gas Price** ($Cdn/ MMbtu)	**NYMEX Gas ($US/ MMbtu)**	**Edmonton Ethane** ($Cdn/Bbl)	**Edmonton Propane** ($Cdn/Bbl)	**Edmonton Butane** ($Cdn/Bbl)	**Edmonton C5+ Stream Quality ($/Bbl)**	**Inflation Rates (3) %/Year**	**Exchange Rate (4)** ($US/ $Cdn)
Forecast												
2020	61.00	71.71	50.92	69.56	2.08	2.42	6.42	28.68	48.76	77.80	0.0	0.76
2021	63.00	74.03	54.58	71.81	2.35	2.75	7.36	31.09	51.82	79.22	2.0	0.77
2022	66.00	76.92	57.33	74.62	2.55	2.90	8.05	34.62	54.62	83.33	2.0	0.78
2023	68.00	80.13	59.71	77.72	2.65	3.00	8.39	36.06	56.89	86.54	2.0	0.78
2024	70.00	82.69	62.27	80.21	2.75	3.10	8.73	37.21	58.71	89.10	2.0	0.78
2025	72.00	85.26	64.83	82.70	2.85	3.20	9.08	38.37	60.53	91.67	2.0	0.78
2026	74.00	87.82	67.40	85.19	2.91	3.27	9.29	39.52	62.35	94.23	2.0	0.78
2027	75.81	90.14	69.72	87.44	2.97	3.33	9.48	40.56	64.00	96.55	2.0	0.78
2028	77.33	92.09	71.67	89.33	3.03	3.40	9.69	41.44	65.38	98.50	2.0	0.78
2029	78.88	94.08	73.65	91.25	3.09	3.47	9.91	42.33	66.79	100.49	2.0	0.78
2030+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.78

Notes:

(1) GLJ commodity price forecast effective January 1, 2020.

(2) GLJ assigns a value to our existing physical diversification contracts for natural gas for consuming markets at Dawn, Chicago and Ventura based upon GLJ's commodity price forecast, contracted volumes, and transportation costs. No incremental value is assigned to potential future contracts which were not in place as of December 31, 2019.

(3) Inflation rate for costs.

(4) Exchange rate used to generate the benchmark reference prices in this table.

Weighted average historical prices realized by us for the year ended December 31, 2019, excluding financial derivative commodity contracts were $2.78/Mcf for natural gas, $64.06/Bbl for condensate and oil, and $11.06/Bbl for NGLs (excluding condensate).

Reserves Reconciliation

Over 2019 our reserves increased primarily as a result of our continued delineation and development of the Wapiti Montney play and the delineation of the Charlie Lake light oil play.

RECONCILIATION OF GROSS RESERVES BY PRODUCT TYPE
FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM CRUDE OIL			CONVENTIONAL NATURAL GAS (1)		
	PROVED (Mbbls)	PROBABLE (Mbbls)	PROVED PLUS PROBABLE (Mbbls)	PROVED (MMcf)	PROBABLE (MMcf)	PROVED PLUS PROBABLE (MMcf)
December 31, 2018	1,826	598	2,425	19,245	5,540	24,784
Discoveries	-	-	-	-	-	-
Extensions	1,612	2,619	4,230	5,469	9,038	14,507
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(260)	(150)	(411)	3,007	21	3,028
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	1	(1)	-	(66)	(28)	(94)
Production	(157)	-	(157)	(3,016)	-	(3,016)
December 31, 2019	3,021	3,066	6,087	24,639	14,571	39,210

	NATURAL GAS LIQUIDS			SHALE GAS		
	PROVED (Mbbls)	PROBABLE (Mbbls)	PROVED PLUS PROBABLE (Mbbls)	PROVED (MMcf)	PROBABLE (MMcf)	PROVED PLUS PROBABLE (MMcf)
December 31, 2018	110,365	69,847	180,213	1,255,089	850,673	2,105,763
Discoveries	-	-	-	-	-	-
Extensions	10,395	6,376	16,711	115,170	84,591	199,762
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	4,881	853	5,734	62,110	10,217	72,327
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	(166)	151	(15)	(52)	56	4
Production	(7,295)	-	(7,295)	(63,532)	-	(63,532)
December 31, 2019	118,180	77,227	195,407	1,368,786	945,538	2,314,324

Note:
(1) Includes solution gas, other associated by-products and an immaterial amount of coal bed methane.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Undeveloped reserves are attributed by GLJ in accordance with standards and procedures contained in the COGE Handbook. Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production. Probable undeveloped reserves are those reserves that are less certain to be recovered than proved reserves and are expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

In some cases, it will take longer than two years to develop these reserves. We plan to develop the proved undeveloped reserves in the GLJ Report over the next five years and the probable undeveloped reserves over the next ten years. There are a number of factors that could result in delayed or cancelled development, including the following: (i) changing economic conditions (due to pricing, operating and capital expenditure fluctuations); (ii) changing technical conditions (including production anomalies, such as water breakthrough or accelerated depletion); (iii) multi-zone developments (for instance, a prospective formation completion may be delayed until the initial completion is no longer economic); (iv) a larger development program may need to be spread out over several years to optimize capital allocation and facility utilization; and (v) surface access issues (including those relating to land owners, weather conditions and regulatory approvals). For more information, see "*Risk Factors*".

Proved Undeveloped Reserves

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were attributed in each of the most recent three financial years.

	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		SHALE GAS (MMcf)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2017	-	-	111,664	437,149
2018	903	903	513,417	911,481
2019	1,338	2,072	64,497	959,739

	CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2017	-	-	11,396	36,854
2018	5,389	5,389	44,541	77,384
2019	4,567	10,232	5,652	79,644

Of our total proved plus probable gross reserves, 243,379 MBoe or 41% are proved undeveloped gross reserves. These well locations are allocated reserves because they are within the defined distances to proved reserve accumulations. The Wapiti Montney play accounts for 238,693 MBoe or 98% of our proved undeveloped reserves. Subject to market conditions, we expect to develop approximately 13,300 MBoe of these reserves in 2020 and 59,400 MBoe in 2021. The remaining proved undeveloped reserves are planned to be developed within an additional three year time period subject to capital availability and allocation and regulatory and gas processing considerations.

The development and delineation of the Wapiti Montney is the primary focus of our business. We continue to employ a disciplined approach to our business plan to ensure the infrastructure and other requirements are in place to develop the strong economics reserves of our proved undeveloped locations within the timeline reflected in the GLJ Reserve Report, subject to capital availability and allocation and regulatory and gas processing considerations.

Probable Undeveloped Reserves

The following table discloses, for each product type, the volumes of probable undeveloped gross reserves that were first attributed in each of our most recent three financial years.

	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		SHALE GAS (MMcf)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2017	-	-	224,521	606,839
2018	296	296	254,552	692,763
2019	2,520	2,769	90,938	783,046

	CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2017	-	-	24,767	52,818
2018	1,765	1,765	21,292	55,241
2019	8,700	10,047	7,352	62,599

Of our total proved plus probable reserves, 197,551 MBoe or 33% are probable undeveloped gross reserves. These well locations are allocated reserves because they are within the defined distances to proved reserve accumulations. The Montney play accounts for 191,993 MBoe or 97% of our probable undeveloped reserves. Subject to market conditions, we expect to develop approximately 8,200 MBoe of these reserves in 2020 and 21,000 MBoe in 2021. Remaining probable undeveloped reserves are planned to be developed within an additional eight year time period subject to capital availability and allocation and regulatory and gas processing considerations.

The development and delineation of the Wapiti Montney is the primary focus of our business. We continue to employ a disciplined approach to our business plan to ensure the infrastructure and other requirements are in place to develop the strong economics reserves of our probable undeveloped locations within the timeline reflected in the GLJ Reserve Report, subject to capital availability and allocation and regulatory and gas processing considerations.

Significant Factors or Uncertainties

Changes in future commodity prices relative to the forecasts provided under "*Pricing Assumptions*" above could have a negative impact on our reserves and in particular the development of our undeveloped reserves unless future development costs are adjusted in parallel. We are also committed to deliver a certain amount of our production in accordance with various processing and transportation agreements. Any changes or disruptions to these agreements could have an effect on our reserves. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Marketing Arrangements*" and "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Processing and Transportation*". Other than the foregoing and the factors disclosed or described above, we do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our reserves data. However, our reserves can be affected significantly by fluctuations in product pricing, capital expenditures, operating costs, royalty regimes and well performance that are beyond our control. See "*Risk Factors*".

Additional Information Concerning Abandonment and Reclamation Costs

Our overall abandonment and reclamation costs are based on well bore abandonment and reclamation costs and liability issues such as flare pit remediation, facility decommissioning, remediation, and reclamation costs. These costs were estimated using our experience conducting abandonment and reclamation programs. We review suspended or standing well bores for reactivation, recompletion or sale and conduct systematic abandonment programs for those well bores that do not meet our criteria. A portion of our liabilities are retired every year and facilities are decommissioned when all the wells producing to them have been abandoned. All of our liability reduction programs take into account seasonal access, high priority and stakeholder considerations, and opportunities for multi-location programs to reduce costs.

As at December 31, 2019, we had approximately 696 net wells for which we expect to incur abandonment and reclamation costs and 496 net wells that have been abandoned but not yet reclaimed. As disclosed in our December 31, 2019 year end financial statements, we calculated our estimated overall abandonment and reclamation costs at $127 million (undiscounted and uninflated). This cost discounted is $35 million (10% discount). Included in this calculation are the abandonment and reclamation costs for our ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities.

The future net revenues disclosed in this Annual Information Form based on the GLJ Reserve Report contain the abandonment and reclamation costs of all of our existing and future wells, facilities and pipelines. The GLJ Reserve Report deducted $279 million (undiscounted total proved) and $36 million (10% discount) for abandonment and reclamation costs, in estimating the future net revenue disclosed in this Annual Information Form.

Future Development Costs

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below:

	FORECAST PRICES AND COSTS	
YEAR	PROVED RESERVES ($000s)	PROVED PLUS PROBABLE RESERVES ($000s)
2020	156,311	184,740
2021	479,741	516,206
2022	497,545	560,655
2023	494,141	541,459
2024	394,596	429,165
Remaining	-	875,988
Total (Undiscounted)	2,022,335	3,108,211

We expect to fund the development costs of our reserves through a combination of internally generated cash flow from operating activities, debt and equity issuances. There can be no guarantee that funds will be available to us or that our Board of Directors will allocate funding to develop all of the reserves attributed in the GLJ Reserve Report. Failure to develop those reserves could have a negative impact on our future cash flow from operating activities. See "*Risk Factors*".

Interest or other costs of external funding are not included in our reserves and future net revenue estimates and would reduce reserves and future net revenue to some degree depending upon the funding sources utilized. We do not anticipate that interest or other funding costs would make development of any of our properties uneconomic.

Other Oil and Natural Gas Information

Principal Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2019. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

Wapiti - Montney

Wapiti, our largest operating area is located south of Grande Prairie, Alberta, approximately 600 kilometers northwest of Calgary. This operating area continues to play the fundamental role in our future growth with substantially all our projected 2020 capital budget expected to be spent in this region.

We hold Montney rights in approximately 163,200 gross acres (145,920 net acres) of land with an average working interest of 90% that are prospective for the Triassic Montney zone resource play. This formation is typified by high rate condensate-rich natural gas. As of the end of 2019, NuVista had 187 horizontal wells developed in the Montney formation.

Production from the Montney in the Wapiti area is currently processed at one of four large area processing plants: the NuVista Wembley plant, the SemCAMS K3 plant, the Keyera Simonette plant, and the SemCAMS Wapiti plant.

Our interests in the Montney are concentrated in four main areas within the Greater Wapiti Area – Bilbo, Gold Creek, Elmworth, and Pipestone.

Bilbo

During 2019, Bilbo production averaged 16,030 Boe/d, which included 6,320 Bbls/d of condensate, 744 Bbls/d of NGLs (excluding condensate), and 53,794 Mcf/d of conventional natural gas. Operations during the year included drilling of eight Montney horizontal wells, which were brought on stream to fill surplus capacity at the Bilbo compressor station. A two well pad was drilled and was brought on stream in the first quarter of 2020 and an additional two well pad is currently being drilled.

Gold Creek

Production at Gold Creek averaged 7,976 Boe/d in 2019 which included 2,663 Bbls/d of condensate, 488 Bbls/d of NGLs (excluding condensate), and 28,952 Mcf/d of conventional natural gas. Operations during the year included drilling of eight Montney horizontal wells which were brought on stream to fill new capacity at the SemCAMS Wapiti Gas Plant. Start-up of the SemCAMS Wapiti Gas plant occurred in 2019 and production was rerouted from the SemCAMS K3 plant to the Wapiti Plant. An additional three well pad was drilled in the first quarter and is currently being brought on stream.

Elmworth

Elmworth production averaged 13,965 Boe/d in 2019 which included 3,228 Bbls/d of condensate, 1,637 Bbls/d of NGLs (excluding condensate), and 54,599 Mcf/d of conventional natural gas. Operations during the year included drilling five Montney horizontal wells from two pad sites early in the year which were brought on production to fill surplus capacity at the Elmworth compressor station. An additional four well pad was drilled in the first quarter of 2020 and is planned to be brought on stream in the second quarter.

Pipestone

Production at Pipestone averaged 10,492 Boe/d in 2019 which included 2,347 Bbls/d of condensate, 2,025 Bbls/d of NGLs (excluding condensate), and 36,715 Mcf/d of conventional natural gas. Operations during the year included drilling of 10 Montney horizontal wells in the Pipestone South Block, which came on production in the third and fourth quarter of 2019. Start-up of the Pipestone South Compressor Station which is owned by CSV Midstream and contract operated by NuVista occurred late in the third quarter of 2019. An additional six well pad was also spud prior to year end and is being brought on-stream late in the first quarter of 2020.

In the Pipestone North Block, steady production was achieved from the 28 legacy Montney horizontal wells. Construction of infrastructure projects such as the Pipestone North Compressor Station and the fresh water storage reservoir commenced in the second half of 2019. NuVista also drilled one Paddy/Cadotte water disposal well and recompleted a water source well in the Cardium formation. All these projects will support the Montney growth development in 2020. A 12 well pad is currently being drilled that will be brought on stream in the fourth quarter of 2020. Production from this pad will be processed at the Veresen Hythe Gas Plant. This 12 well pad targets four layers of cube development in the Montney formation.

Non-core Areas

Production in the non-core area of Wembley, which is in the greater Wapiti-Montney area, was 2,241 Boe/d in 2019 which included 179 Bbls/d of condensate, 351 Bbls/d of NGLs (excluding condensate), 431 Bbls/d of light and medium oil, and 7,682 Mcf/d of conventional natural gas.

We also have non-core operations in three additional areas of Alberta (non-core properties outside of the greater Wapiti-Montney area) whose combined production in 2019 averaged 99 Boe/d compared to 430 Boe/d in 2018 due to asset divestitures and production decline. Substantially all of the 2019 average non-core production is comprised of conventional natural gas. These operating regions combined gross acreage in 2019 is 330,025 gross acres (249,868 net acres). We are not anticipating spending any development capital in 2020 and did not drill any wells in these regions in the last three years.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2019.

	OIL WELLS				NATURAL GAS WELLS			
	PRODUCING		NON-PRODUCING (2)		PRODUCING		NON-PRODUCING (2)	
	GROSS	NET	GROSS	NET	GROSS	NET	GROSS	NET
Alberta (1)	94.0	31.2	181.0	123.3	295.0	219.1	1,080.0	853.2

Notes:

(1) The table does not include 3 gross (2.2 net) non-producing natural gas wells located in Saskatchewan.

(2) Included in the non-producing wells are 66 gross (49.2 net) oil wells and 559 gross (454.3 net) natural gas wells that are abandoned but have not yet completed reclamation.

Properties With No Attributed Reserves

As at December 31, 2019 we held 57,600 gross acres (47,843 net acres) of Montney rights to which no reserves are currently attributed. Rights to explore, develop and exploit 10,342 net acres of these land holdings could expire by December 31, 2020 if not continued. We have no material work commitments other than abandonment obligations on these properties and the majority of this acreage is located in our non-core operating areas. When determining gross and net acreage, where we hold two or more leases granting stratigraphic interests which overlap geographically, the acreage is reported for each lease; where we hold two or more stratigraphic interests in a single lease that overlap geographically, the acreage is reported only once.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

We do not anticipate any significant economic factors or significant uncertainties will affect any particular components of our properties with no attributed reserves. There are no unusually significant abandonment and reclamation costs with our properties with no attributed reserves. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Significant Factors or Uncertainties – Additional Information Concerning Abandonment and Reclamation Costs*" and "*Risk Factors*".

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties. For information in relation to our marketing arrangements, see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Marketing Arrangements*". For details of our material commitments to sell natural gas and crude oil which were outstanding as at December 31, 2019 see Note 20 to our financial statements for the year ended December 31, 2019.

A part of our ongoing strategy is to secure transportation and processing to ensure our production moves to market over the short and long term. We believe that securing firm takeaway and processing capacity is prudent management of our business and as such have secured sufficient takeaway for future growth.

The amount by which our volume commitments exceed the forecast production of our proved and proved plus probable reserves based on the GLJ Reserve Report and the estimated cost to us to meet these commitments are summarized below.

RESERVE CATEGORY	PROVED		PROVED PLUS PROBABLE	
YEARS	2020 – 2024	2025 - 2036	2020 - 2024	2025 – 2036
Conventional Natural Gas (MMcf/d)	27	-	-	-
Condensate & NGL/s (Bbls/d)	5,145	7,748	1,900	1,311
Estimated Cost (millions)	43	113	13	19

We expect to fulfill these commitments through our ongoing exploration and development activities subject to our ongoing development plans, well performance and disruptions or constraints at facilities and pipelines. For a summary of our transportation and processing commitments which were outstanding as at December 31, 2019 see Note 23 to our financial statements for the year ended December 31, 2019.

Marketing Arrangements

Natural Gas

We have established a natural gas transportation and sales portfolio, which will ensure receipt capacity at reasonable cost and provide an appropriate customer base. Our marketing objectives also include protecting or securing minimum prices for up to 70% of our forecast net after royalty production for the term January 1, 2020 to June 30, 2021 and up to 60% for July 1, 2021 to December 31, 2022 and a further 50% for the following 24 months. In addition, we may enter into natural gas basis differential contracts, subject to a maximum volume of up to 150,000 MMbtu/day and with a term of less than 7 years from the date any such swap is entered into, that are the lesser of 50% of forecast natural gas production, net of royalties, or the volumes that would bring the combined natural gas basis differential contracts and natural gas fixed price contracts to 100% of forecast natural gas production, net of royalties.

Our price risk management program is comprised of costless collars, differentials, fixed price and put option contracts. In order to control and manage credit risk and ensure competitive bids, we engage a number of reputable counterparties for our natural gas transactions. The integration and application of these strategies resulted in an average realized price (excluding financial derivative commodity contracts) of $2.78/Mcf for the year ended December 31, 2019.

We have been contracting for export pipeline capacity to diversify our gas sales to other regional markets. We contracted for 20 MMcf/d of Alliance pipeline capacity to the Chicago market area that started December 2015 and is renewable on an annual evergreen basis. In 2018, we contracted an additional 40 MMcf/d of Alliance pipeline capacity starting in late 2020 for 10 years at posted tolls. In 2016, we contracted for 40,000 GJ/d of delivery service on the Nova system to the Alberta/BC border which will allow for gas exports to northern California. This service commenced in April 2018 after the Sundre Crossover project was completed by Nova. This contract has a minimum tenure of 5 years and has indefinite rights of first refusal. In 2017, we contracted for 44,486 GJ/d of Dawn long term fixed price delivery service that started November 2017 and has a maximum term of 10 years. The combination of these export pipeline contracts will provide for a more diverse portfolio of gas markets and prices beyond AECO. We will continue to evaluate other downstream gas marketing opportunities as they arise.

Oil and NGLs

We sell our oil and liquids production to a variety of purchasers. This enables us to benefit from specific regional advantages, while maintaining price and delivery flexibility. We are continually monitoring global and regional crude oil and NGL markets and look for opportunities to enter into price risk management contracts for up to 70% of forecast net after royalty production for the term January 1, 2020 to June 30, 2021, up to 60% for the next 18 months and up to 30% for the following 24 months. In 2019, our average realized condensate & oil price (excluding financial derivative commodity contracts) was $64.06/Bbl and our average realized price for natural gas liquids (excluding condensate) was $11.06/Bbl. For additional details on our price risk management program see Note 21 to our financial statements for the year ended December 31, 2019.

Processing and Transportation

Most of our natural gas and associated natural gas liquids production requires processing to meet sales quality specifications. We require pipeline transportation to deliver our raw natural gas and NGLs to these processing facilities. Access to processing and pipeline transportation is critical to the development of our Wapiti Montney condensate-rich natural gas play. We have entered into long-term take-or-pay contracts to ensure access to processing and pipelines for current and future production. We have made the strategic decision to own most of the gathering and compression facilities required for production from our Wapiti Montney play but we rely on third-party owned infrastructure for the processing and transportation of our production.

In May 2014, we entered into a 10-year processing and transportation agreement with SemCAMS for 47 MMcf/d of raw natural gas starting in mid-2015. In October 2014, we entered into an agreement to increase these volumes a further 30 MMcf/d in mid-2016 for a total commitment of 77 MMcf/d of raw natural gas transportation and processing.

In April 2013, we entered into a 10-year processing, transportation and marketing agreement with Keyera Corp. for 35 MMcf/d of raw natural gas starting in the third quarter of 2014, increasing to 65 MMcf/d late in the fourth quarter of 2014. In early 2014, we entered into an agreement to increase these volumes to 80 MMcf/d in the third quarter of 2015. In addition to these raw natural gas processing and transportation arrangements, we have entered into agreements for the transportation and fractionation of our natural gas liquids produced from the above raw gas processing arrangements.

On October 11, 2016, we entered into an agreement as anchor tenant with SemCAMS ULC for firm processing of an additional 120 MMcf/d of raw gas from our condensate rich Montney play in the Wapiti area of Alberta. The processing capacity will be added in three incremental steps of 40 MMcf/d, commencing in 2019, 2020, and 2021 respectively. The agreement is underpinned by take-or-pay terms for a period of 15 years, and the 80% take-or-pay terms provide flexibility to produce above or below these firmly contracted amounts. The capacity will be provided via the new 200 MMcf/d gas plant at Gold Creek that began operations in early 2019. We will supply gas to this contract from the Gold Creek, Pipestone, Elmworth, and surrounding areas. In 2018 we entered into an agreement with SemCAMS ULC to construct the Pipestone Pipeline Project to connect our Pipestone South compressor station to the new plant in Gold Creek. Contracted transportation of raw gas will be added in two incremental steps with 40 MMcf/d that started late in the third quarter 2019, increasing to 60 MMcf/d by mid-2020. Bilbo and adjacent southern lands will continue to be processed at the Keyera Simonette gas plant. When added to our existing capacity, the SemCAMS ULC gas plant agreement will expand our total Wapiti area firm processing capacity to approximately 277 MMcf/d of raw gas by 2021.

As part of the Pipestone Acquisition, we acquired a 39% operating working interest in the Wembley gas plant which has a total gross capacity of approximately 100 MMcf/d. Our existing Wembley and Pipestone North volumes flow through the Wembley gas plant.

On November 1, 2018, we entered in an agreement as anchor tenant with Veresen Midstream Limited Partnership ("**VMLP**") for firm transportation and processing of 100 MMcf/d of raw gas from our newly acquired Pipestone North block of lands. The processing capacity will be added in three tranches, 50 MMcf/d commencing in late 2020, 25 MMcf/d commencing in late 2021, and 25 MMcf/d commencing in late 2022. The 15 year agreement is underpinned by 80% take-or-pay terms. The capacity will be provided by the expansion of the VMLP owned Hythe gas plant and the construction of a new sour gas pipeline connecting a portion of our Pipestone North production to the Hythe Gas Plant. In addition, we have entered into an agreement with a third party shipper for firm transportation service on Alliance Pipeline to Chicago for natural gas sales volumes from the first tranche of raw processing capacity starting late 2020 for a minimum period of 10 years at posted tolls.

Most of the condensate produced from our Wapiti Montney play is extracted in the field at compressor stations. These condensate volumes are either transported by pipeline or truck to sales points. We have entered into long-term condensate pipeline transportation agreements to access additional pipeline capacity and reduce the need for higher cost trucking transportation of condensate production.

Tax Horizon

Based on estimated 2020 cash flow from operating activities and capital expenditures, and existing tax assets, we do not expect to be cash taxable in 2020. Projecting taxability beyond 2020 is subject to many uncertainties including commodity prices, capital spending, acquisitions, divestments and government regulations and guidelines. Within the context of current commodity prices and our capital spending plans, we do not expect to be taxable in the next five years.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2019:

EXPENDITURE	YEAR ENDED DECEMBER 31, 2019 ($000s)
Property acquisition costs – Unproved properties (1)	1,133
Property acquisition costs – Proved properties	-
Exploration costs (2)	7,961
Development costs (3)	292,242
Other	486
Total	301,822

Notes:
(1) Cost of land acquired and non-producing lease rentals on those lands.
(2) Geological and geophysical capital expenditures and drilling costs for exploration wells.
(3) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells, and are net of proceeds received for the funding of assets under construction by third party ownership.

Exploration and Development Activities

In 2019, we drilled 31 (31.0 net) condensate-rich natural gas development wells, 2 (2.0 net) oil wells, and 1 (1.0 net) disposal wells within our Wapiti Montney resource play.

Subject to market conditions, in 2020, we expect to drill approximately 20 condensate-rich natural gas wells within our Wapiti Montney resource play. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

Production History

The following table summarizes certain information in respect of our production, product prices received, royalties paid, production costs and resulting netback for the periods indicated below:

	QUARTER ENDED 2019				YEAR ENDED DEC 31, 2019
	MAR. 31	JUNE 30	SEPT. 30	DEC. 31	
Average Daily Production					
Light and Medium Crude Oil (Bbls/d)	352	373	584	412	431
Natural Gas (Mcf/d)	159,224	180,589	184,681	204,275	182,322
NGLs (Bbls/d) (1)	4,549	5,342	5,310	5,769	5,246
Condensate (Bbls/d) (1)	12,400	14,578	15,144	16,783	14,740
Combined (Boe/d)	43,839	50,391	51,819	57,010	50,803
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	60.44	68.60	63.86	62.41	63.84
Natural Gas ($/Mcf)	3.92	2.39	2.24	2.74	2.78
NGLs ($/Bbl) (1)	18.79	6.61	4.85	12.57	11.06
Condensate ($/Bbl) (1)	60.18	69.81	63.43	62.51	64.07
Combined ($/Boe)	33.98	30.04	27.86	29.83	30.26
Royalties Paid					
Light and Medium Crude Oil ($/Bbl)	13.59	15.70	18.84	11.72	15.39
Natural Gas ($/Mcf) (5)	(0.14)	(0.19)	(0.15)	(0.07)	(0.14)
NGLs ($/Bbl) (1)	1.58	0.53	0.34	0.76	0.77
Condensate ($/Bbl) (1)	4.90	6.33	6.42	6.47	6.10
Combined ($/Boe)	1.16	1.32	1.57	1.82	1.49
Production Costs (2)(3)					
Light and Medium Crude Oil ($/Bbl)	0.07	0.07	0.11	0.07	0.08
Natural Gas ($/Mcf)	0.94	0.95	0.99	0.96	0.96
NGLs ($/Bbl) (1)	0.97	1.01	1.02	0.97	0.99
Condensate ($/Bbl) (1)	2.63	2.74	2.91	2.84	2.79
Combined ($/Boe)	9.31	9.49	9.97	9.63	9.61
Transportation Costs					
Light and Medium Crude Oil ($/Bbl)	0.07	1.78	1.50	1.48	1.33
Natural Gas ($/Mcf)	0.84	0.74	0.72	0.67	0.74
NGLs ($/Bbl) (1)	-	-	-	-	-
Condensate ($/Bbl) (1)	0.38	1.82	1.54	1.51	1.36
Combined ($/Boe)	3.16	3.17	3.03	2.83	3.04
Netback Received (4)					
Light and Medium Crude Oil ($/Bbl)	46.71	51.05	43.41	49.14	47.04
Natural Gas ($/Mcf)	2.36	0.92	0.71	1.15	1.24
NGLs ($/Bbl) (1)	16.24	5.07	3.49	10.84	8.66
Condensate ($/Bbl) (1)	52.27	58.92	52.56	51.69	53.82
Combined ($/Boe)	20.35	16.06	13.29	15.55	16.12

Notes:

(1) For the purposes of this table condensate has been shown separately from natural gas liquids.

(2) Production costs are composed of direct costs incurred to operate wells that produce any one or more of the product types that are shown. Costs have been allocated to products based on production volumes on a pro-rata basis.

(3) Overhead recoveries associated with operated properties are charged to production costs and accounted for as a reduction to general and administrative costs.

(4) Netbacks are calculated by subtracting royalties, production costs and transportation from revenues. See "*Non-GAAP Measures*".

(5) Natural gas royalties paid are net of Alberta gas cost allowance credits.

The following table indicates our average daily production for the year ended December 31, 2019:

	LIGHT AND MEDIUM CRUDE OIL (Bbls/d)	NATURAL GAS LIQUIDS (Bbls/d)	CONDENSATE (1) (Bbls/d)	NATURAL GAS (Mcf/d)	TOTAL (Boe/d)
Wapiti Montney	-	4,894	14,559	174,060	48,463
Non-core	430	352	181	8,262	2,340
Total	430	5,246	14,740	182,322	50,803

Note:
(1) For the purposes of this table condensate has been shown separately from natural gas liquids.

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2020, which is reflected in the estimates of future net revenue disclosed in the forecast price tables contained above under the subheading "*Reserves Data (Forecast Prices and Costs)*":

	LIGHT AND MEDIUM OIL (Bbls/d)	CONVENTIONAL NATURAL GAS (1) (Mcf/d)	NATURAL GAS LIQUIDS (Bbls/d)	SHALE GAS (Mcf/d)	TOTAL (Boe/d)
Total Proved	811	7,975	20,548	195,441	55,262
Total Proved plus Probable	886	8,239	22,434	212,610	60,128

Note:
(1) Includes an immaterial amount of coal bed methane.

DIVIDENDS

We have not declared dividends on our Common Shares since November of 2010. Any decision to pay dividends on the Common Shares will be made by our Board of Directors on the basis of our earnings, financial requirements and other conditions that the Board of Directors may consider appropriate in the circumstances. It is not intended that dividends will be paid in the foreseeable future as we are focused upon profitable growth and capital discipline.

DESCRIPTION OF OUR CAPITAL STRUCTURE

Credit Facility

We are currently party to a credit agreement (the "**Credit Agreement**") with a syndicate of lenders which, as at the date hereof, provides for a $525 million extendible revolving line of credit and a $25 million operating line of credit for a total of $550 million (collectively, the "**Credit Facility**"). The Credit Facility is a two year revolving facility with a current maturity date of April 30, 2021. Upon our request, and with the consent of lenders holding at least 66⅔% of the commitment amounts under the Credit Facility, the maturity date of consenting lenders will be extended for a period of up to two years from the date of extension. See "*Risk Factors – Credit Facility Arrangements*". The available lending limits of the Credit Facility are reviewed semi-annually and are based on the lenders' assessment of our reserves and future commodity prices.

We are in compliance with all material terms of the Credit Agreement and no lender has waived or been requested to waive any material breach by us of such agreement since its execution. Neither our financial position nor the value of the security under the Credit Agreement has changed substantially and adversely since the initial indebtedness under the Credit Facility was incurred.

Advances under the Credit Facility are available by way of Canadian prime rate and U.S. base rate loans with interest rates between 0.50 percent and 2.50 percent over the bank's prime lending rate and bankers' acceptances and LIBOR loans, which are subject to stamping fees and margins ranging from 1.50 percent to 3.50 percent depending upon our senior funded debt to EBITDA ratio calculated at our previous quarter end.

As at December 31, 2019, our applicable pricing included a 1.00 percent per annum margin on prime loans, a 2.00 percent per annum stamping fee and margin on bankers' acceptances and LIBOR loans along with a 0.45 percent per annum standby fee on the portion of the Credit Facility that is not drawn. Borrowing margins and fees are reviewed annually as part of the bank syndicate's annual review. At December 31, 2019, we had issued letters of credit totaling $7.3 million. The effective interest rate per annum on our borrowings under our Credit Facility for the twelve months ended December 31, 2019 was 3.3% per annum.

The indebtedness under the Credit Agreement is secured by floating charges and a security interest against our current and future real and personal property. We do not currently have any subsidiaries and, as such, no guarantees have been provided under the Credit Agreement.

The Credit Agreement contains customary borrowing base provisions and negative covenants including, but not limited to, restrictions on our ability to incur indebtedness, grant liens or security interests on assets, sell or otherwise transfer assets, make distributions, make investments or provide financial assistance and our ability to merge and consolidate with other companies or change our line of business, in each case, subject to certain exceptions.

The Credit Agreement 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 Credit Agreement provides that, upon the occurrence of certain events of default, our obligations thereunder may be accelerated and the lending commitments terminated. Such events of default include payment defaults to the lenders, covenant defaults, inaccuracies of representations and warranties, bankruptcy and insolvency proceedings, business suspension, material money judgments, cross defaults, change of control and other customary events of default.

Senior Unsecured Notes

On March 2, 2018, we issued $220.0 million aggregate principal amount of the 2023 Notes. Interest on the 2023 Notes is payable semi-annually in arrears. The 2023 Notes are fully and unconditionally guaranteed as to the payment of principal and interest, on a senior unsecured basis by us. There are no maintenance financial covenants.

The 2023 Notes are non-callable prior to March 2, 2020. At any time on or after March 2, 2020, we may redeem all or part of the 2023 Notes at the redemption prices set forth in the table below plus any accrued and unpaid interest:

12 month period ended:	Percentage
March 2, 2021	103.250%
March 2, 2022	101.625%
March 2, 2023	100.000%

If a change of control occurs, each holder of the 2023 Notes will have the right to require us to purchase all or any part of that holder's 2023 Notes for an amount in cash equal to 101% of the aggregate principal repurchased plus accrued and unpaid interest.

Part of the proceeds from the 2023 Notes were used to redeem all of the 2021 Notes. The full aggregate principal amount of the 2021 Notes of $70.0 million was redeemed plus an agreed redemption premium of $6.6 million.

Share Capital

We are authorized to issue an unlimited number of Common Shares without nominal or par value and no other shares. Holders of our Common Shares are entitled to one vote per share at meetings of our Shareholders. Subject to the rights of the holders of and any other shares having priority over the Common Shares, holders of Common Shares are entitled to dividends if, as and when declared by the Board of Directors and upon liquidation, dissolution or winding-up to receive, our remaining property.

Ratings

As of the date hereof, we received a corporate credit rating of B and the 2023 Notes have received a rating of B+ from S&P Global Ratings, a division of S&P Global Canada Corp. ("**S&P**"). The corporate rating addresses our overall credit strength and the rating on the 2023 Notes is intended by the rating agency to provide an independent indication of the risk that a borrower will not fulfill its obligations with respect to a given type and/or service of security in a timely manner with respect to both physical and interest components. There has been no change in these ratings in 2019 and as at the date of this Annual Information Form**.** Given current market and industry conditions, there is a material risk that our ratings will be lowered.

The credit ratings assigned by rating agencies are not recommendations to purchase, hold or sell any of our securities and such credit ratings may be subject to revision or withdrawal at any time by the credit rating organizations.

S&P rates long-term debt instruments by rating categories ranging from a high of "AAA" to a low of "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 minus (-) sign to show relative standing within the major rating categories. The B category is the sixth highest of the ten available categories.

We paid customary fees to S&P in connection with the abovementioned ratings. We did not make any payments to S&P in respect of any other service provided to us by S&P during the last two years.

MARKET FOR SECURITIES

Trading Price and Volume

Our Common Shares are listed and posted for trading on the Toronto Stock Exchange and trade under the symbol "NVA". The following sets forth the price range and trading volume of our Common Shares on the Toronto Stock Exchange for the periods indicated.

	PRICE RANGE		
	HIGH	LOW	VOLUME
2019			
January	4.70	3.93	25,749,018
February	4.56	3.67	22,749,018
March	4.90	4.09	23,981,594
April	5.14	4.19	17,818,785
May	4.35	2.84	22,189,664
June	3.03	2.46	20,836,111
July	2.82	2.36	25,999,370
August	2.71	1.39	50,168,582
September	2.69	1.55	46,041,051
October	2.51	1.88	16,059,768
November	2.64	1.86	16,991,379
December	3.24	2.27	15,467,459
2020			
January	3.36	2.11	21,055,288
February	2.40	1.84	16,370,380
March (1 - 20)	2.01	0.24	43,509,567

Prior Sales

During the year ended December 31, 2019, we issued a total of 1.8 million options pursuant to our stock option plan, 0.7 million restricted share awards and 0.8 million performance share awards pursuant to our share award plan and 0.2 million deferred share units pursuant to our director deferred share unit incentive plan. No funds are received by us until the options are exercised. See Note 20 of our financial statements for the year ended December 31, 2019 for a summary of stock option, restricted share award and performance share award activity.

DIRECTORS AND OFFICERS

The names, municipalities of residence, any offices held with us, the period served as a director and principal occupations of our directors and officers are set out below:

NAME AND MUNICIPALITY OF RESIDENCE	POSITION WITH NUVISTA	DIRECTOR OR OFFICER SINCE	PRINCIPAL OCCUPATION
Keith A. MacPhail (2)(3) Calgary, Alberta	Chair and Director	May 2003	Our Chair, Chair of Bonavista Energy Corporation and Director of Cenovus Energy Inc.
Ronald J. Eckhardt (2) (3) Calgary, Alberta	Director	March 2013	Former Executive Vice-President, North American Operations for Talisman Energy Inc., Chair of Athabasca Oil Corporation.
Pentti O. Karkkainen (1)(3)(5) West Vancouver, British Columbia	Director	July 2003	Former General Partner, KERN Partners Ltd. (a private equity firm and partnership), Director of AltaGas Ltd.
Ronald J. Poelzer (1)(3) Calgary, Alberta	Director	May 2003	Vice Chair of Bonavista Energy Corporation.
Brian G. Shaw (1)(4) Toronto, Ontario	Director	August 2014	Director of Ovintiv Inc., Manulife Bank of Canada and Manulife Trust Company.
Sheldon B. Steeves (2)(4) Calgary, Alberta	Director	March 2013	Former CEO and Chair of Echoex Ltd., a private oil and natural gas exploration and production company. Director of Enerplus Corporation and PrairieSky Royalty Ltd.
Deborah S. Stein (1) (4) Heritage Pointe, Alberta	Director	August 2016	Former Senior Vice President Finance and Chief Financial Officer of AltaGas Ltd. Director of Aecon Group Inc., Parkland Fuel Corporation, and Trican Well Service Ltd.
Grant A. Zawalsky (4) Calgary, Alberta	Director	May 2003	Managing Partner of Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Jonathan A. Wright Calgary, Alberta	President and Chief Executive Officer and a Director	May 2011	Our President and Chief Executive Officer and a Director since May 2011.
Ross L. Andreachuk Calgary, Alberta	Vice President, Finance and Chief Financial Officer and Corporate Secretary	May 2009	Our Vice President, Finance and Chief Financial Officer since September, 2014. Prior thereto, Mr. Andreachuk was our Vice President and Controller.
Mike J. Lawford Calgary, Alberta	Chief Operating Officer	January 2012	Our Chief Operating Officer since December 5, 2017. Prior thereto, our Vice President, Development since January 2012.

NAME AND MUNICIPALITY OF RESIDENCE	POSITION WITH NUVISTA	DIRECTOR OR OFFICER SINCE	PRINCIPAL OCCUPATION
Kevin G. Asman Calgary, Alberta	Vice President, Marketing	January 2010	Our Vice President, Marketing.
Chris M.A. LeGrow Calgary, Alberta	Vice President, Development and Planning	May 2019	Our Vice President, Development and Planning. Prior thereto, our Manager, Planning & Corporate Development
Joshua T. Truba Calgary, Alberta	Vice President, Land & Business Development	January 2009	Our Vice President, Land & Business Development.
Ryan D. Paulgaard Airdrie, Alberta	Vice President, Production and Facilities	December 2017	Our Vice President, Production and Facilities since December 5, 2017. Prior thereto, our Manager of Production

Notes:
(1) Member of our Audit Committee.
(2) Member of our Reserves Committee.
(3) Member of our Corporate Governance & Compensation Committee.
(4) Member of our Environment, Social and Governance Committee.
(5) Our Lead Director.

The term of office of each of our directors expires at the next annual meeting of our Shareholders.

As at the date of this Annual Information Form, our directors and officers, as a group, beneficially owned, or directed or controlled, directly or indirectly, 10.4 million Common Shares or 4.6% of our issued and outstanding Common Shares.

Corporate Cease Trade Orders, Bankruptcies or Penalties or Sanctions

None of our directors or executive officers (nor any personal holding company of any of such persons) is, as of the date of this Annual Information Form, or was within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of any company (including us), that was subject to a cease trade order (including a management cease trade order), an order similar to a cease trade order or an order that denied the relevant company access to any exemption under securities legislation, in each case that was in effect for a period of more than 30 consecutive days (collectively, an "**Order**") that was issued while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or was subject to an Order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer.

None of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, as of the date of this Annual Information Form, or has been within the ten years before the date of this Annual Information Form, a director or executive officer of any company (including us) that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets, other than Mr. Zawalsky who was a former director of Endurance Energy Ltd. (a private oil and gas company) which filed for creditor protection under the *Companies Creditors' Agreement Act* on May 30, 2016. Mr. Zawalsky resigned as a director of Endurance Energy Ltd. on November 1, 2016.

None of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, has, within the ten years before the date of this Annual Information Form, 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, executive officer or Shareholder.

None of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us, has been subject to 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 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

Our directors and officers may, from time to time, be involved with the business and operations of other oil and natural gas issuers, in which case a conflict may arise. See "*Risk Factors*".

Circumstances may arise where members of our Board of Directors serve as directors or officers of corporations which are in competition to our interests. No assurances can be given that opportunities identified by such Board of Directors members will be provided to us.

The *Business Corporations Act* (Alberta) provides that in the event a director has an interest in a contract or proposed contract or agreement, the director shall disclose his interest in such contract or agreement and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under the *Business Corporations Act* (Alberta). To the extent that conflicts of interests arise, such conflicts will be resolved in accordance with the provisions of the *Business Corporations Act* (Alberta).

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

The full text of our Audit Committee charter is included in Appendix C of this Annual Information Form.

Composition of the Audit Committee

The members of our Audit Committee are Deborah Stein (Chair), Mr. Karkkainen, Mr. Poelzer and Mr. Shaw each of whom are independent and financially literate. We have adopted the definition of "independence" as set out in Section 1.4 of National Instrument 52-110 – *Audit Committees*. The relevant education and experience of each Audit Committee member is outlined below.

Deborah Stein: Corporate Director

Ms. Stein has over 30 years of industry experience, including 20 years of direct experience in the oil and gas business, most recently having held the position of Senior Vice President and Chief Financial Officer at AltaGas Ltd. Prior to joining AltaGas in 2005, Ms. Stein held various positions at TransCanada Corporation. Ms. Stein also led the finance functions of Wendy's Restaurants of Canada and Paramount Canada's Wonderland. She is currently a director of Aecon Group Inc., Parkland Fuel Corporation, Trican Well Service Ltd. and various private companies.

Ms. Stein is a Fellow Chartered Professional Accountant, holds a designation from the Institute of Corporate Directors and obtained her Bachelor of Arts degree from York University, majoring in Economics.

Pentti O. Karkkainen: Independent Businessman

Mr. Karkkainen has over 30 years of investment management, energy sector research and investment banking experience, as well as four years of industry experience with Gulf Canada Resources. Mr. Karkkainen was a Co-Founder and General Partner of KERN Partners, a leading Canadian based energy focused capital markets and private equity firm, from September 2000 to July 2014 and was the firm's Senior Strategy Advisor from July, 2014 until his retirement from the firm in August, 2015. Prior to establishing KERN Partners, Mr. Karkkainen was Managing Director and Head of Oil and Gas Equity Research at RBC Capital Markets.

Mr. Karkkainen holds a Bachelor of Science (Honours) degree in Geology from Carleton University in Ottawa, a Masters of Business Administration degree from Queen's University in Kingston, and a designation from the Institute of Corporate Directors.

Ronald J. Poelzer: Bonavista Energy Corporation

Mr. Poelzer has more than 30 years of experience in the oil and gas industry and is currently Vice Chair of Bonavista Energy Corporation. Prior thereto, Mr. Poelzer was Executive Vice President and Vice Chair of Bonavista responsible for various strategic planning, business development, financial and capital market roles. Prior to joining Bonavista in 1997, Mr. Poelzer was with Poco Petroleum Ltd. as Vice President, Business Development. Prior thereto, Mr. Poelzer was in public accounting practice.

Mr. Poelzer is a Chartered Professional Accountant and holds a Bachelor of Commerce (Distinction) degree from the University of Saskatchewan.

Mr. Poelzer is also a member of the board of directors of various private companies and a charitable foundation.

Brian G. Shaw: Independent Businessman

Mr. Shaw is an experienced financial industry executive with particular expertise in capital markets and investing activities. He is currently a director of Ovintiv Inc., Manulife Bank of Canada and Manulife Trust Company.

Mr. Shaw is an alumni of CIBC World Markets Inc. (and its predecessor firm Wood Gundy) where he was employed for 23 years. He was Chair and Chief Executive Officer of CIBC World Markets Inc. from 2005 through 2008 and prior to that managed the Global Equities Division for a number of years. Mr. Shaw is a Chartered Financial Analyst and holds a Masters of Business Administration from the University of Alberta and a Bachelor of Commerce from the University of Alberta.

Pre-Approval of Policies and Procedures

Our Audit Committee must pre-approve all non-audit services to be provided to us by our external auditors. The Audit Committee may delegate to one or more members the authority to pre-approve non-audit services, provided that the member reports to the Audit Committee at the next scheduled meeting such pre-approval and the member complies with such other procedures as may be established by our Audit Committee from time to time.

External Auditor Service Fees

The following table summarizes the fees paid by us to our auditors, KPMG LLP, for external audit and other services during the periods indicated.

YEAR	AUDIT FEES (1) ($)	AUDIT-RELATED FEES (2) ($)	TAX FEES (3) ($)
2019	355,000	-	22,500
2018	488,000	58,500	3,750

Notes:
(1) Represents fees billed by our external auditor for audit services.
(2) Represents fees billed for assurance related services by our external auditor that are reasonably related to the performance of the audit or review of our financial statements that are not reported under audit fees.
(3) Represents fees billed for professional services rendered by our external auditor for tax compliance, tax advice and tax planning.

Reliance on Exemptions

At no time since the commencement of our most recently completed financial year have we relied on any of the exemptions contained in National Instrument 52-110 – *Audit Committees* with respect to independence or composition of our Audit Committee.

Audit Committee Oversight

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

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 crude oil and natural gas properties, along with related assets, primarily in the province of 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 primarily in the province of Alberta.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers. As a result, macroeconomic and microeconomic market forces determine the price of crude oil. Worldwide supply and demand factors are the primary determinant of crude oil prices; however, regional market and transportation issues also influence prices. The specific price depends, in part, on crude 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 ("**CER**"), and replacing the National Energy Board (the "**NEB**") with the 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 *Canadian Energy Regulator Act* (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. We do not directly enter into contracts to export our 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 areas 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 "*Regulatory Authorities and Environmental Regulation – British Columbia*" in these Industry Conditions.

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 "*Regulatory Authorities and Environmental Regulation – Federal*" in these Industry Conditions.

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/d 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. On February 11, 2010, the Government of Alberta announced that it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

In February 2020, the federal government announced that trains hauling more than 20 cars carrying dangerous goods, including crude oil and diluted bitumen, would be subject to reduced speed limits, following two derailments that led to fires and oil spills in Saskatchewan. These reduced speed limits will remain in effect until April 1, 2020.

Natural Gas

Natural gas prices in Alberta 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 joint venture partners of the LNG Canada liquefied natural gas export terminal announced a positive final investment decision to proceed with the project, which will allow LNG Canada to transport natural gas from northeastern British Columbia to the LNG Canada liquefaction facility and export terminal in Kitimat, BC, via the Coastal GasLink pipeline, which will be built and operated by TC Energy's subsidiary Coastal GasLink ("**CGL**") (the "**CGL Pipeline**"). Pre-construction activities began in November 2018, with a completion target of 2025. In late 2019, TC Energy announced that it would sell 65% of its interest in the CGL Pipeline, to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. The transaction is expected to close in the first half of 2020. The CGL Pipeline's route was altered as a result of feedback that LNG Canada received from Indigenous groups in the area, and on May 1, 2019, the British Columbia Oil and Gas Commission (the "**BC Commission**") approved the current planned route for the CGL Pipeline. However, the CGL Pipeline has faced intense opposition. For example, a challenge to the approval process of the CGL Pipeline was launched in August 2018, contending that it should have been subject to the federal review instead of a provincial review. In July 2019, the NEB confirmed that the CGL Pipeline was properly subject to provincial jurisdiction. In addition, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have caused delays of construction activities on the CGL Pipeline. Coastal Gaslink Pipeline Ltd. obtained an injunction on December 31, 2019, and enforcement of the injunction started in February 2020.

On February 19, 2020, the British Columbia Environmental Assessment Office (the "**EAO**") directed CGL to re-engage and consult further with Unist'ot'en, one of the Wet'suwet'en clans opposed to the pipeline route, regarding the impacts of the pipeline on a nearby healing centre. The EAO prescribed a 30-day timeline for the completion of these consultations and CGL is permitted to continue pre-construction work in the relevant area.

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 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 Bbls/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 venturers 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 Bbls/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. The Curtailment rules are set to be repealed by December 31, 2020.

We are not subject to a curtailment order since the majority of our liquids production is condensate which is exempt from curtailment.

The North American Free Trade Agreement and Other Trade Agreements

NAFTA/ USMCA

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**". The USMCA must be ratified by legislative bodies in the three signatory countries 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 until the legislative bodies of the three signatory countries ratify the USMCA. 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 our 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. We do not have material 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.

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, provincially-set royalty rates apply to Crown-owned mineral rights. In 2016, the Government of Alberta adopted a modernized 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 Alberta Energy Regulator (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.

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.

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 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 Impact Assessment Agency of Canada ("**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 IA 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 non-designated 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

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 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 our 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 us, 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. We are participating in the voluntary ABC program.

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 our operations and cash flow from operating activities.

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 have referred the constitutionality of the GGPPA to their respective Courts of Appeal. In both the Saskatchewan and Ontario references, the appellate Courts ruled in favour of the constitutionality of the GGPPA. The Attorneys General of Saskatchewan and Ontario have appealed these decisions to the Supreme Court of Canada and the Court is set to hear the appeals in March 2020. On February 24, 2020, the Alberta Court of Appeal determined that the GGPPA is unconstitutional. It is unclear whether the Alberta reference will be appealed and heard with the Saskatchewan and Ontario appeals or, relatedly, whether those scheduled hearings will be delayed as a result. However, each of Saskatchewan, Ontario and Alberta will participate in the scheduled hearings, along with the Attorneys General of Quebec, New Brunswick, Manitoba and British Columbia and various other interested parties.

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.

Finally, the federal government has also enacted the Multi-Sector Air Pollutants Regulation under the authority of the *Canadian Environmental Protection Act, 1999*, which seeks to regulate certain industrial facilities and equipment types, including boilers and heaters used in the upstream oil and natural gas industry, to limit the emission of air pollutants such as nitrogen oxides and sulphur dioxide.

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 CO_2 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.

Accountability and Transparency

In 2015, the federal government's *Extractive Sector Transparency Measures Act* (the “**ESTMA**”) came into effect, which imposed mandatory reporting requirements on certain entities engaged in the "commercial development of oil, gas or minerals", including exploration, extraction and holding permits. All companies subject to ESTMA must report payments over CAD$100,000 made to any level of a Canadian or foreign government (including indigenous groups), including royalty payments, taxes (other than consumption taxes and personal income taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to Shareholders), infrastructure improvement payments and other prescribed categories of payments.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in our other public filings before making an investment decision. The risks set out below are not an exhaustive list and should not be taken as a complete summary or description of all the risks associated with our business and the oil and natural gas business generally.

Prices, Markets and Marketing

Our ability to market our oil and natural gas may depend upon our ability to acquire capacity in pipelines that deliver oil, NGLs and natural gas to commercial markets or contract for the delivery of crude oil and NGLs by rail. Numerous factors beyond our control do, and will continue to, affect the marketability and price of oil and natural gas acquired, produced, or discovered by us, including:

- deliverability uncertainties related to the distance our reserves are from pipelines, railway lines and processing and storage facilities;
- operational problems affecting pipelines, railway lines and processing and storage facilities; and
- government regulation relating to prices, taxes, royalties, land tenure, allowable production and the export of oil and natural gas.

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, shale oil production in the United States, Organization of the Petroleum Exporting Countries ("**OPEC**") actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries, conflicts in the Middle East and ongoing credit and liquidity concerns. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. 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. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash flow from operating activities and may have a material adverse effect on our business, financial condition, results of operations and prospects.

See "*Industry Conditions – Transportation Constraints and Marketing*" and "*Risk Factors – Weakness and Volatility in the Oil and Natural Gas Industry*".

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 and exploitation projects.

Weakness and Volatility in the Oil and Natural Gas Industry

Market events and conditions, including global excess oil and natural gas supply, recent actions taken by OPEC and Russia, sanctions against Iran and Venezuela, slowing growth in China and emerging economies, weakening global relationships, conflict between the U.S. and Iran, isolationist and punitive trade policies, U.S. shale production, sovereign debt levels and political upheavals in various countries including growing anti-fossil fuel sentiment, have caused significant volatility in commodity prices. See "*Political Uncertainty*" in these Risk Factors. These events and conditions have caused a significant reduction in the valuation of oil and natural gas companies and a decrease in confidence in the oil and natural gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. See "*Royalties and Incentives*", "*Regulatory Authorities and Environmental Regulation*" and "*Climate Change Regulation*" in these Risk Factors. In addition, the difficulties encountered by midstream proponents to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and natural gas industry in Western Canada has led to additional downward price pressure on oil and natural gas produced in Western Canada. The resulting price differential between Western Canadian Select crude oil, and Brent and West Texas Intermediate crude oil has created uncertainty and reduced confidence in the oil and natural gas industry in Western Canada. See "*Industry Conditions – Transportation Constraints and Market Access*".

Global or national health concerns, including the outbreak of pandemic or contagious diseases, such as COVID-19 (coronavirus), have and will continue to adversely affect us by (i) reducing global economic activity thereby resulting in lower demand for crude oil, NGLs and natural gas and reducing commodity prices, (ii) impairing our supply chain (for example, by limiting the manufacturing of materials or the supply of services used in our operations), and (iii) affecting the health of our workforce, rendering employees unable to work or travel.

Lower commodity prices may also affect the volume and value of our reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict our cash flow from operating activities resulting in less cash flow from operating activities being available to fund our capital expenditure budget. Consequently, we may not be able to replace our production with additional reserves and both our production and reserves could be reduced on a year-over-year basis. See "*Reserves Estimates*" in these Risk Factors. Any decrease in value of our reserves may reduce the borrowing base under the Credit Facility, which, depending on the level of our indebtedness, could result in us having to repay a portion of our indebtedness. See "*Credit Facilities*" in these Risk Factors. In addition to possibly resulting in a decrease in the value of our economically recoverable reserves, lower commodity prices may also result in a decrease in the value of our infrastructure and facilities, all of which could also have the effect of requiring a write down of the carrying value of our oil and natural gas assets on our balance sheet and the recognition of an impairment charge in our income statement. Given the current market conditions and the lack of confidence in the Canadian oil and natural gas industry, we may have difficulty raising additional funds or if we are able to do so, it may be on unfavourable and highly dilutive terms. See "*Additional Funding Requirements*" in these Risk Factors.

Political Uncertainty

In the last several years, the United States and certain European countries have experienced significant political events that have cast uncertainty on global financial and economic markets. Since the 2016 U.S. presidential election, the American administration withdrew the United States from the Trans-Pacific Partnership and Congress has passed sweeping tax reform, which, among other things, significantly reduces U.S. corporate tax rates. This has affected competitiveness of other jurisdictions, including Canada.

In addition, NAFTA has been renegotiated and on November 30, 2018, Canada, the U.S. and Mexico signed the USMCA which will replace NAFTA once ratified by the three signatory countries. The USMCA was ratified by Mexico's Senate in June 2019 and by the United States' Senate in January 2020. In late January 2020, the Canadian Parliament tabled Bill C-4, which once proclaimed into force, will ratify the USMCA.

The USMCA is expected to fully replace NAFTA two months after Bill C-4 comes into force. See "*Industry Conditions – The North American Trade Agreement and Other Trade Agreements*". The U.S. administration has also taken action with respect to reduction of regulation, which may also affect relative competitiveness of other jurisdictions. It is unclear exactly what other actions the U.S. administration will implement, and if implemented, how these actions may impact Canada and in particular the oil and natural gas industry. Any actions taken by the current U.S. administration may have a negative impact on the Canadian economy and on the businesses, financial conditions, results of operations and the valuation of Canadian oil and natural gas companies, including us.

In addition to the political disruption in the United States, the impact of the United Kingdom exit from the European Union remains to be determined. Some European countries have also experienced the rise of anti-establishment political parties and public protests held against open-door immigration policies, trade and globalization. Conflict and political uncertainty also continues to progress in the Middle East. To the extent that certain political actions taken in North America, Europe and elsewhere in the world result in a marked decrease in free trade, access to personnel and freedom of movement, it could have an adverse effect on our ability to market our products internationally, increase costs for goods and services required for our operations, reduce access to skilled labour and negatively impact our business, operations, financial conditions and the market value of our Common Shares.

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. In January 2020, 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, tensions remain high 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 where we are active. See "*Industry Conditions – Transportation Constraints and Market Access*".

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. Lack of political consensus, 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. See "*Industry Conditions – Climate Change Regulation*", "*Industry Conditions – Transportation Constraints and Market Access*", "*Industry Conditions – Curtailment*" and "*Industry Conditions – The North American Free Trade Agreement and other Trade Agreements*".

The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development - particularly with respect to infrastructure projects. Protests, blockades, and demonstrations have the potential to delay and disrupt our activities. See "*Industry Conditions – Transportation Constraints and Market Access – Natural Gas*".

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 produces 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, our management may determine that current markets, terms of acquisition, participation or pricing conditions make potential acquisitions or participation uneconomic. There is also no assurance that we will discover or acquire further commercial quantities of oil and natural gas.

Future oil and natural gas exploration may involve unprofitable efforts from dry wells or from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, completing (including hydraulic fracturing), operating and other costs. Completion of a well does not ensure a profit on the investment or recovery of drilling, completion and operating costs.

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, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or 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 from operating activities levels to varying degrees.

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. Particularly, we may explore for and produce sour gas in certain areas. An unintentional leak of sour gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us.

Oil and natural gas production 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 our business, financial condition, results of operations and prospects.

As is standard industry practice, we are not fully insured against all risks, nor are all risks insurable. Although we maintain liability insurance and business interruption insurance in an amount that we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. See "*Insurance*" in these Risk Factors. In either event, we could incur significant costs.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through various gathering and processing facilities and pipeline systems. -- 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. Notwithstanding the Government of Alberta's plans to lease 4,400 rail cars and the implementation of production curtailment in Alberta, the ongoing lack of availability of capacity in any of the gathering and processing facilities, pipeline systems and railway lines could result in our inability to realize the full economic potential of our production, or in a reduction of the price offered for our production. The lack of firm pipeline capacity continues to affect the oil and natural gas industry and limits the ability to transport produced oil and natural gas to market. However, in early 2020, the Supreme Court of Canada and the Federal Court of Appeal both dismissed challenges to Cabinet's approval of the Trans Mountain Pipeline expansion, and construction on the pipeline expansion is underway. See "*Industry Conditions - Transportation Constraints and Market Access*". 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 CERA, 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 our production may, from time to time, be processed through facilities owned by third parties and over which we do 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 our ability to process our 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.

Market Price of our Common Shares

The trading price of the 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, the volatility, trading volume and share price of issuers have been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, 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 operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which our Common Shares will trade cannot be accurately predicted.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider 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 own. The integration of acquired businesses and assets 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 by third parties and the resources required to provide such services. In this regard, non-core assets may be periodically disposed of so we can focus our efforts and resources more efficiently. Depending on market conditions for such non-core assets, we may realize less on a disposition than their carrying value on our financial statements.

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.

In addition, due to 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 reimbursement 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, us potentially becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on our financial and operational results. See "*Industry Conditions – Liability Management Rating Program*" and "*Third Party Credit Risk*" in these Risk Factors.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project interruptions may delay expected revenues from operations. Significant project cost overruns could make a project uneconomic. Our ability to execute projects and market oil and natural gas depends upon numerous factors beyond our control, including:

- availability of processing capacity;
- availability and proximity of pipeline capacity;
- availability of storage capacity;
- availability of, and the ability to acquire, water supplies needed for drilling, hydraulic fracturing, and waterfloods or our ability to dispose of water used or removed from strata at a reasonable cost and in accordance with applicable environmental regulations;
- effects of inclement and severe weather events, including fire, drought and flooding;
- availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- regulatory changes;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, we could be unable to execute projects on time, on budget, or at all.

Environmental

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, the initiation and approval of new oil and natural gas projects, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. New environmental legislation at the federal and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions – Exports from Canada*", "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Climate Change Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. 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. Although we believe that we are in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements 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.

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 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.

Disposal of Fluids Used in Operations

The safe disposal of the hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase our costs of compliance.

Substantial Capital Requirements

We anticipate making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors:

- the overall state of the capital markets;
- our credit rating (if applicable);
- commodity prices;
- interest rates;
- royalty rates;
- tax burden due to current and future tax laws; and
- investor appetite for investments in the energy industry and our securities in particular.

Further, if our revenues or reserves decline, we may not have access to the capital necessary to undertake or complete future drilling programs. The conditions in, or affecting, the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies, including us, to access additional financing and/or the cost thereof. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to us. We may be required to seek additional equity financing on terms that are highly dilutive to existing Shareholders. Our inability to access sufficient capital for our operations could have a material adverse effect on our business financial condition, results of operations and prospects.

Additional Funding Requirements

Our future net revenue from our reserves may not be sufficient to fund our ongoing activities at all times and, from time to time, we may require additional financing in order to carry out our oil and natural gas acquisition, exploration and development activities. Failure to obtain financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. Due to the conditions in the oil and natural gas industry and/or global economic and political volatility, we may, from time to time, have restricted access to capital and increased borrowing costs. The current conditions in the oil and natural gas industry have negatively impacted the ability of oil and natural gas companies to access, as well as the cost of, additional financing.

As a result of global economic and political conditions and the domestic lending landscape, we may, from time to time, have restricted access to capital and increased borrowing costs. Failure to obtain suitable financing on a timely basis could cause us to forfeit our interest in certain properties, miss certain acquisition opportunities and reduce or terminate our operations. If our revenues from our reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect our ability to expend the necessary capital to replace our reserves or to maintain our production. To the extent that external sources of capital become limited, unavailable or available on onerous terms, our ability to make capital investments and maintain existing assets may be impaired, and our assets, liabilities, business, financial condition and results of operations may be affected materially and adversely as a result. In addition, the future development of our petroleum properties may require additional financing and there are no assurances that such financing will be available or, if available, will be available upon acceptable terms. Alternatively, any available financing may be highly dilutive to existing

Shareholders. Failure to obtain any financing necessary for our capital expenditure plans may result in a delay in development or production on our properties.

Reserves Estimates

There are numerous uncertainties inherent in estimating reserves, and the future net revenue attributed to such reserves. The reserves and associated future net revenue information set forth in this Annual Information Form are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves (including the breakdown of reserves by product type) and the future net revenues from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from properties;
- production rates;
- 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 and future operating costs (all of which may vary materially from actual results).

For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times may vary. Our actual production, revenues, taxes and development and operating expenditures with respect to our reserves will vary from estimates and such variations could be material.

The estimation of proved reserves that may be developed and produced in the future is often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas are often estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, our independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net revenues as summarized herein. Actual future net revenues will 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.

Actual production and future net revenue derived from our oil and natural gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities we intend to undertake in future years. The reserves and estimated future net revenue to be derived therefrom and contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation is effective as of a specific effective date and, except as may be specifically stated, has not been updated and therefore does not reflect changes in our reserves since that date.

Credit Ratings

Credit ratings affect our ability to obtain short term and long term financing and the cost of such financing. Additionally, our ability to engage in ordinary course derivative or hedging transactions and maintain ordinary course contracts with customers and suppliers on acceptable terms depends on our credit ratings. A reduction in the current rating on the 2023 Notes or a negative change in our rating outlook could adversely affect our cost of financing and access to sources of liquidity and capital. Given current market and industry conditions, there is a material risk that our ratings will be lowered.

Credit ratings are intended to provide investors with an independent measure of credit quality of any issuer of securities. The credit rating accorded to the 2023 Notes are not recommendations to purchase, hold or sell the securities in as much as ratings do not comment as to market price or suitability for a particular investor. Any rating may not remain in effect for any given period of time or may be revised or withdrawn entirely by a rating agency in the future if in its judgment circumstances so warrant.

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 ours. 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 we do. 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.

Information Technology Systems and Cyber-Security

We have become increasingly dependent upon the availability, capacity, reliability and security of our information technology infrastructure and our ability to expand and continually update this infrastructure, to conduct daily operations. We depend on various information technology systems to estimate reserve quantities, process and record financial data, manage our land base, manage financial resources, analyze seismic information, administer our contracts with our operators and lessees and communicate with employees and third-party partners.

Further, we are subject to a variety of information technology and system risks as a part of our normal course operations, including 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. In addition, cyber phishing attempts, in which a malicious party attempts to obtain sensitive information such as usernames, passwords, and credit card details (and money) by disguising as a trustworthy entity in an electronic communication, have become more widespread and sophisticated in recent years. If we become a victim to a cyber phishing attack it could result in a loss or theft of our financial resources or critical data and information, or could result in a loss of control of our technological infrastructure or financial resources. Our employees are often the targets of such cyber phishing attacks, as they are and will continue to be targeted by parties using fraudulent "spoof" emails to misappropriate information or to introduce viruses or other malware through "Trojan horse" programs to our computers. These emails appear to be legitimate emails, but direct recipients to fake websites operated by the sender of the email or request recipients to send a password or other confidential information through email or to download malware.

We maintain policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conduct annual cyber-security risk assessments. We also employ encryption protection of our confidential information, all computers and other electronic devices. Despite our efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage our information technology infrastructure. We apply technical and process controls in line with industry-accepted standards to protect our information, assets and systems, including a written incident response plan for responding to a cyber-security incident. However, these controls may not adequately prevent cyber-security breaches. 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, and any damages sustained may not be adequately covered by our current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on our business, financial condition and results of operations.

Social Media

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into our systems and obtain confidential information. We restrict the social media access of our employees and periodically review, supervise, retain and maintain the ability to retrieve social media content. Despite these efforts, as social media continues to grow in influence and access to social media platforms becomes increasingly prevalent, there are significant risks that we may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

Cost of New 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 implement and benefit from technological advantages. 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. If we do implement such technologies, there is no assurance that we will do so successfully. 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 also be affected adversely and materially. If we are unable to utilize the most advanced commercially available technology, or are unsuccessful in implementing certain technologies, our business, financial condition and results of operations could also be adversely affected in a material way.

Alternatives to and Changing Demand for Petroleum Products

Full conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation systems could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. 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 flow from operating activities by decreasing our profitability, increasing our costs, limiting our access to capital and decreasing the value of our assets.

Reputational Risk Associated with our Operations

Our business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards us or as a result of any negative sentiment toward, or in respect of, our reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which we operate as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. Our reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which we have no control. Similarly, our reputation could be impacted by negative publicity related to loss of life, injury or damage to property and environmental damage caused by our operations. In addition, if we develop a reputation of having an unsafe work site, it may impact our ability to attract and retain the necessary skilled employees and consultants to operate our business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and fossil fuel companies may impact our reputation. See "*Climate Change*" in these Risk Factors.

Reputational risk cannot be managed in isolation from other forms of risk. Credit, market, operational, insurance, regulatory and legal risks, among others, must all be managed effectively to safeguard our reputation. Damage to our reputation could result in negative investor sentiment towards us, which may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of the Common Shares.

Changing Investor Sentiment

A number of factors, including the effects of the use of fossil fuels on climate change, the impact of oil and natural gas operations on the environment, environmental damage relating to spills of petroleum products during production and transportation and Indigenous rights, have affected certain investors' sentiments towards investing in the oil and natural gas industry. As a result of these concerns, some institutional, retail and governmental investors have announced that they no longer are willing to fund or invest in oil and natural 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 the 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 natural gas industry and more specifically, us, may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our securities even if our operating results, underlying asset values or prospects have not changed. Additionally, these factors, as well as other related factors, may cause a decrease in the value of our asset which may result in an impairment change.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing, transportation and infrastructure). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties, the exportation of oil and natural gas and infrastructure projects. Amendments to these controls and regulations may occur, from time to time, in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for crude oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". Also, in response to widening pricing differentials, the Government of Alberta implemented production curtailment. See "*Industry Conditions – Curtailment"*. Also see "*Liability Management*" in these Risk Factors.

In order to conduct oil and natural gas operations, we will require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. 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. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect our business, financial condition and the market value of our Common Shares or our assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Program*".

Royalty Regimes

There can be no assurance that the governments in the jurisdictions in which we have assets 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. See "*Industry Conditions – Royalties and Incentives*".

Carbon Pricing Risk

The majority of countries across the globe have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In Canada, the federal government implemented legislation aimed at incentivizing the use of alternative fuels and in turn reducing carbon emissions. The federal system currently applies in provinces and territories without their own system that meets federal standards. The federal regime is subject to a number of court challenges. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". Any taxes placed on carbon emissions may have the effect of decreasing the demand for oil and natural gas products and at the same time, increasing our operating expenses, each of which may have a material adverse effect on our profitability and financial condition. Further, the imposition of carbon taxes puts us at a disadvantage with our counterparts who operate in jurisdictions where there are less costly carbon regulations.

Liability Management

Alberta has developed liability management programs 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 regulatory obligations. Changes to the AB LMR Program administered by the AER or other changes to the requirements of liability management programs, may result in significant increases to our compliance obligations. The impact and consequences of the Supreme Court of Canada's decision in Redwater 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 are expected to evolve as the consequences of the decision are evaluated and considered by regulators, lenders and receivers/trustees. In addition, the AB LMR Program may prevent or interfere with our ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and natural 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. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Program*".

Climate Change

Chronic Climate Change Risks

Our exploration and production facilities and other operations and activities emit GHGs which may require us to comply with federal and/or provincial GHG emissions legislation. 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 to prevent climate change or mitigate its effects. 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.

Climate change has been linked to long-term shifts in climate patterns, including sustained higher temperatures. As the level of activity in the Canadian oil and natural gas industry is influenced by seasonal weather patterns, long-term shifts in climate patterns pose the risk of exacerbating operational delays and other risks posed by seasonal weather patterns. See "*Seasonality*" in these Risk Factors. 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 (time and capital) to deal with the challenges posed by such changes to our premises, operations, supply chain, transport needs, and employee safety. Specifically, in the event of water shortages or sourcing issues, we may not be able to, or will incur greater costs to, carry out hydraulic fracturing operations.

Concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels which has influenced investors' willingness to invest in the oil and natural gas industry. Historically, political and legal opposition to the fossil fuel industry focused on public opinion and the regulatory process. More recently, however, there has been a movement to more directly hold governments and oil and natural gas companies responsible for climate change through climate litigation. In November 2018, Environment JEUnesse, a Quebec advocacy group, applied to the Quebec Superior Court to certify all Quebecois under 35 as a class in a proposed class action lawsuit against the Government of Canada for climate related matters. While the application was denied, the group has stated it plans to appeal. In January 2019, the City of Victoria became the first municipality in Canada to endorse a class action lawsuit against oil and natural gas producers for alleged climate-related harms. The Union of British Columbia Municipalities defeated the City of Victoria's motion to initiate a class action lawsuit to recover costs it claims are related to climate change.

Given the evolving nature of climate change policy 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 potentially reducing the demand for oil and natural gas production, resulting in a decrease in our profitability and a reduction in the value of our assets or requiring asset impairments for financial statement purposes. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*" and "*Non-Governmental Organizations*", "*Reputational Risk Associated with the Our Operations*" and "*Changing Investor Sentiment*" in these Risk Factors.

Acute Climate Change Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict our ability to access our properties, or cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of our assets are located in locations that are proximate to forests and rivers, and a wildfire or flood may lead to significant downtime and/or damage to such assets. Moreover, extreme weather conditions may lead to disruptions in our ability to transport produced oil and natural gas as well as goods and services in our supply chain.

Variations in Foreign Exchange Rates and Interest Rates

World oil and natural gas prices are quoted in United States dollars. The Canadian/United States dollar exchange rate, which fluctuates over time, consequently affects the price received by Canadian producers of oil and natural gas. Material increases in the value of the Canadian dollar relative to the United States dollar will negatively affect our production revenues. Accordingly, exchange rates between Canada and the United States could affect the future value of our reserves as determined by independent evaluators. Although a low value of the Canadian dollar relative to the United States dollar may positively affect the price we receive for our oil and natural gas production, it could also result in an increase in the price for certain goods used for our operations, which may have a negative impact on our financial results**.**

To the extent that we engage in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which we may contract.

An increase in interest rates could result in a significant increase in the amount we pay to service debt, resulting in a reduced amount available to fund our exploration and development activities, and if applicable, the cash available for dividends. Such an increase could also negatively impact the market price of our Common Shares.

Credit Facility Arrangements

The amount authorized under our Credit Facility is dependent on the borrowing base determined by our lenders. We are required to comply with certain non-financial covenants under the Credit Facility and in the event that we do not comply with these covenants, our access to capital could be restricted or repayment could be required. Events beyond our control may contribute to our failure to comply with such covenants. A failure to comply with covenants could result in default under our Credit Facility, which could result in us being required to repay amounts owing thereunder. The acceleration of our indebtedness under one agreement may permit acceleration of indebtedness under other agreements that contain cross default or cross-acceleration provisions. In addition, our Credit Facility may impose operating and financial restrictions on us that could include restrictions on, repurchase or making of other distributions with respect to our securities, incurring of additional indebtedness, the provision of guarantees, the assumption of loans, making of capital expenditures, entering into of amalgamations, mergers, take-over bids or disposition of assets, among others.

Our lenders use our reserves, commodity prices, applicable discount rate and other factors to periodically determine our borrowing base. Commodity prices continue to be depressed and have fallen dramatically since 2014, and while prices remain volatile as a result of various factors including COVID 19, limited egress options for Western Canadian oil and natural gas producers, actions taken to limit OPEC and non-OPEC production and increasing production by US shale producers. Depressed commodity prices could reduce our borrowing base, reducing the funds available to us under the Credit Facility. This could result in the requirement to repay a portion, or all, of our indebtedness.

As a result of the Supreme Court of Canada's decision in the Redwater case, secured creditors will be subject to prior satisfaction of abandonment and restoration claims which may not be capable of quantification at the time credit is advanced. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Program*".

We are required to maintain LMR levels at agreed-upon thresholds and we are restricted from completing asset dispositions and acquisitions that would result in our LMR levels falling below such thresholds. We are also required to provide additional reporting to our lenders regarding our existing and/or budgeted abandonment and reclamation obligations, our decommissioning expenses, our LMR and/or any notices or orders received from an energy regulator in any applicable province. If there is a decline in our LMR below the agreed threshold or if we become subject to an abandonment and reclamation order and our estimated cost of compliance with such order exceeds a certain threshold, we could be required to repay our credit facilities. See also *"Industry Conditions –- Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

If our lenders require repayment of all or a portion of the amounts outstanding under our Credit Facility for any reason, including for a default of a covenant, or the reduction of a borrowing base, there is no certainty that we would be in a position to make such repayment. Even if we are able to obtain new financing in order to make any required repayment under our Credit Facility, it may not be on commercially reasonable terms, or terms that are acceptable to us. If we are unable to repay amounts owing under the Credit Facility, the lenders could proceed to foreclose or otherwise realize upon the collateral granted to them to secure the indebtedness.

Issuance of Debt

From time to time, we may enter into transactions to acquire assets or shares of other entities. These transactions may be financed in whole, or in part, with debt, which may increase our debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, we may require additional debt financing that may not be available or, if available, may not be available on favourable terms. Neither our articles nor our by-laws limit the amount of indebtedness that we may incur. The level of our indebtedness from time to time could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time, we may enter into agreements to receive fixed prices on our oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that we engage in price risk management activities to protect ourselves from commodity price declines, we may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, our hedging arrangements may expose us to the risk of financial loss in certain circumstances, including instances in which:

- 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;
- counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or
- a sudden unexpected event materially impacts oil and natural gas prices.

Similarly, from time to time, we may enter into agreements to fix the exchange rate of Canadian to United States dollars or other currencies in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to other currencies. However, if the Canadian dollar declines in value compared to such fixed currencies, we will not benefit from the fluctuating exchange rate.

Availability and Cost of Material and Equipment

Oil and natural gas exploration, development and operating activities are dependent on the availability and cost of specialized materials and equipment (typically leased from third parties) in the areas where such activities are conducted. The availability of such material and equipment is limited. An increase in demand or cost, or a decrease in the availability of such materials and equipment may impede our exploration, development and operating activities.

Availability of Skilled Workforce

The operations and management of our business require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement our business plans.

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. We do not have any key personnel insurance in effect. Contributions of the existing management team to our immediate and near term operations are likely to be of central importance. If we are unable to: (i) retain current employees; and/or (ii) recruit new employees with the requisite knowledge and experience, we could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

Title to and Right to Produce from Assets

Our actual title to and interest in our properties, and our right to produce and sell the oil and natural gas therefrom, may vary from our records. In addition, there may be valid legal challenges or legislative changes that affect our title to and right to produce from our oil and natural gas properties, which could impair our activities and result in a reduction of the revenue received by us.

If a defect exists in the chain of title or in our right to produce, or a legal challenge or legislative change arises, it is possible that we may lose all, or a portion of, the properties to which the title defect relates and/or our right to produce from such properties. This may have a material adverse effect on our business, financial condition, results of operations and prospects.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result in us becoming subject to liability for pollution, blowouts, 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. 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.

Geopolitical Risks

Political changes in North America and political instability in the Middle East and elsewhere may cause disruptions in the supply of oil that affects the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or parties in power, may have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and result in a reduction of our net production revenue.

Non-Governmental Organizations

The oil and natural gas exploration, development and operating activities conducted by us may, at times, be subject to public opposition. Such public opposition could expose us to the risk of higher costs, delays or even project cancellations due to increased pressure on governments and regulators by special interest groups including Indigenuous groups, landowners, environmental interest groups (including those opposed to oil and natural gas production operations) and other non-governmental organizations, blockades, legal or regulatory actions or challenges, increased regulatory oversight, reduced support of the federal, provincial or municipal governments, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses, and direct legal challenges, including the possibility of climate-related litigation. See "*Industry Conditions – Transportation Constraints and Market Access*". There is no guarantee that we will be able to satisfy the concerns of the special interest groups and non-governmental organizations and attempting to address such concerns may require us to incur significant and unanticipated capital and operating expenditures.

Dilution

We may make future acquisitions or enter into financings or other transactions involving the issuance of our securities, which may be dilutive to Shareholders.

Management of Growth

We may be subject to growth related risks including capacity constraints and pressure on our internal systems and controls. Our ability to manage growth effectively will require us to continue to implement and improve our operational and financial systems and to expand, train and manage our employee base. If we are unable to deal with this growth, it may have a material adverse effect on our business, financial condition, results of operations and prospects.

Expiration of Licenses and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we, or the holder of the licence or lease, fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of our licences or leases or the working interests relating to a licence or lease and the associated abandonment and reclamation obligations 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 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 and access 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 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 proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse affect on our financial condition.

Intellectual Property Litigation

Due to the rapid development of oil and natural gas technology, in the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings in which it is alleged that we have infringed the intellectual property rights of others or which we initiate against others it believes are infringing upon our intellectual property rights. Our involvement in intellectual property litigation could result in significant expense, adversely affecting the development of our assets or intellectual property or diverting the efforts of our technical and management personnel, whether or not such litigation is resolved in our favour. In the event of an adverse outcome as a defendant in any such litigation, we may, among other things, be required to: (a) pay substantial damages and/or cease the development, use, sale or importation of processes that infringe upon other patented intellectual property; (b) expend significant resources to develop or acquire non-infringing intellectual property; (c) discontinue processes incorporating infringing technology; or

(d) obtain licences to the infringing intellectual property. However, we may not be successful in such development or acquisition, or such licences may not be available on reasonable terms. Any such development, acquisition or licence could require the expenditure of substantial time and other resources and could have a material adverse effect on our business and financial results.

Indigenous Claims

Indigenous peoples have claimed aboriginal title and rights in portions of Western Canada. Except as described in this Annual Information Form under "*Legal Proceedings and Regulatory Actions*", we are not aware that any claims have been made in respect of our properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays in the construction of infrastructure systems and facilities which could have a material adverse effect on our business and financial results.

Breach 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 any 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.

Income Taxes

We file all required income tax returns and believes that we are in full compliance with the provisions of the *Income Tax Act* (Canada) and all other applicable provincial tax legislation. However, such returns are subject to reassessment by the applicable taxation authority. In the event of a successful reassessment of us, whether by re-characterization of exploration and development expenditures or otherwise, such reassessment may have an impact on current and future taxes payable.

Income tax laws relating to the oil and natural gas industry, such as the treatment of resource taxation or dividends, may in the future be changed or interpreted in a manner that adversely affects us. Furthermore, tax authorities having jurisdiction over us may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment.

Seasonality and Extreme 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 which prevents, delays or makes operations more difficult. 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 impassable muskeg. 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.

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, generally, and of our joint venture partners may affect a joint venture 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 a portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

Conflicts of Interest

Certain of our directors or officers may also be directors or officers of other oil and natural gas companies and as such may, in certain circumstances, have a conflict of interest. Conflicts of interest, if any, will be subject to and governed by procedures prescribed by the *Business Corporations Act* (Alberta) which require a director or officer of a corporation who 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 proposed material contract with us to disclose his or her interest and, in the case of directors, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the *Business Corporations Act* (Alberta). See "*Directors and Officers – Conflicts of Interest*".

Firm Commitment Transportation and Processing Arrangements

We may be unable to satisfy our obligations under our firm commitment transportation and processing arrangements. If this occurs, we will be required to satisfy the financial obligations under such firm commitment transportation and processing arrangements and, as a result, will incur the notional cost of transporting volumes of oil, NGLs and/or natural gas that exceed our production, which would adversely affect our financial condition.

Expansion into New Activities

The operations and expertise of our management are currently focused primarily on oil and natural 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 and may acquire different energy related assets; as a result, we may face unexpected risks or, alternatively, our exposure to one or more existing risk factors may be significantly increased, which may in turn result in our future operational and financial conditions being adversely affected.

Forward-Looking Information

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Additional information on the risks, assumption and uncertainties are found under the heading "*Forward Looking Information and Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

In January 2013, a casing failed at one of our wells and we suffered approximately $14 million dollars in damages, $10.5 million in drilling/completion costs and an estimated $3.5 million in lost production. We commenced an action in the Alberta Court of Queen's Bench against the supplier of the casing, Alberta Tubular Products Ltd. ("**ATP**") and the manufacturer of the casing, Welded Tube of Canada Corp. ("**WTC**") on December 5, 2014. ATP filed its Statement of Defence on January 22, 2015. WTC filed its Statement of Defence and brought a cross-claim against ATP on February 20, 2015. No counterclaim was filed by either ATP or WTC against us.

On April 1, 2015, ATP filed third party claims against all of the companies down the casing supply chain. All of the third parties have filed their third party Statements of Defence and the pleadings are now closed. We filed an Affidavit of Records on May 1, 2016. In the fall of 2016, all defendants, and third parties served their Affidavits of Records and provided their document production.

On November 10, 2015, one of the third parties noted by ATP obtained a favourable jury verdict against two other third parties included in the claim by ATP in a related lawsuit in the US District Court for the Southern District of Texas. We are not a party to the Texas action. The jury verdict and trial transcripts from the U.S. action support the claims made within our Alberta action.

In May of 2017, ATP served a Notice to Admit Facts on WTC. We also served a Notice to Admit Facts on WTC in May of 2017. WTC responded to the Notices and made several admissions of facts which will streamline the court proceedings in Alberta.

Experts were retained by all parties to assist with the litigation and the action is moving forward. On October 5, 2018, we served a Summary Judgment application on ATP and WTC to recover damages of $10,508,785.88. On March 22, 2019, ATP served its own Summary Judgment application against WTC for damages on its cross claim against WTC. On the same day, WTC served its own Summary Judgment application on all of the companies down the casing supply chain. Questioning on affidavits was completed over 2019 and a hearing is scheduled for August 6 and 7, 2020.

Chief Joe Danny Pastion on his own behalf and on behalf of all members of Dene Tha' First Nation and Dene Tha' First Nation ("**DTFN**") filed a Statement of Claim on August 10, 2017 in the Court of Queen's Bench in Edmonton relating to the Sousa NW Alberta pipeline spill (which occurred in August 2015) on DTFN reserve lands. We were served with the Statement of Claim on October 30, 2017. The Statement of Claim in general alleges that the spill resulted in toxic and dangerous substances migrating into surface water and ground water on the reserve. The claim alleges that the spill substances adversely impacted flora and fauna and the band's ability to use the reserve. No damage amounts were specified.

We filed a Statement of Defence on February 7, 2019 at DTFN's request. Our Statement of Defence describes our operations and maintenance of the Sousa NW Alberta pipeline, our immediate actions taken upon discovering the pipeline spill, efforts to completely remediate the spill site at a cost to us of approximately $13 million, and denials of liability. Affidavits of Records have not been served.

In 2018, we transitioned our reporting software from Trident Solutions Inc. ("**Trident**") to a product developed by Arcurve Inc. ("**Arcurve**"). The software was installed in late 2018 and we terminated our licensing agreement with Trident as of December 31, 2018. On September 20, 2019, Trident filed a claim against us and Arcurve along with a number of employees of us and Arcurve. The claim alleged that we and Arcurve had conspired to reverse engineer Trident's product thereby breaching the agreement between us and Trident and the copyright over the software that Trident held.

An application was brought in December to have the individual defendants struck from Trident's claim. The application was partially successful as it lead Trident to drop its claims against three of our employees. All the defendants have filed their Statements of Defence and we and Trident have produced their Affidavits of Records. We anticipate coordinating with Arcurve in the spring of 2020 to have this matter summarily dismissed.

Regulatory Actions

There were no: (i) penalties or sanctions imposed against us by a court relating to securities legislation or by a security regulatory authority during the most recently completed financial year; (ii) other penalties or sanctions imposed by a court or regulatory body against us that would likely be considered important to a reasonable investor in making an investment decision; or (iii) settlement agreements we entered into before a court relating to securities legislation or with a securities regulatory authority during our most recently completed financial year.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There are no material interests, direct or indirect, of our directors and senior officers, or any holder of our Common Shares who beneficially owns, or controls or directs, directly or indirectly, more than 10% of our outstanding Common Shares, or any known associate or affiliate of such persons, in any transaction completed within the last three years or in any proposed transaction during the current financial year which have materially affected or are reasonably expected to materially affect us, other than as disclosed herein.

AUDITORS

KPMG LLP, Suite 3100, Bow Valley Square II, 205 – 5th Avenue S.W., Calgary, Alberta, T2P 4B9, is our auditor.

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our Common Shares is Computershare Trust Company of Canada at its principal offices in Calgary, Alberta and in Toronto, Ontario.

MATERIAL CONTRACTS

The only material contract entered into by us within the most recently completed financial year and which is presently material other than in the ordinary course of business, is the Credit Agreement and the note indenture in respect of the 2023 Notes. Copies of these agreements are available on SEDAR at *www.sedar.com*.

INTERESTS 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 National Instrument 51-102 by us during, or related to, our most recently completed financial year other than GLJ, our independent engineering evaluator and KPMG LLP, our independent auditors.

KPMG 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.

None of the designated professionals of GLJ 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, except for Grant A. Zawalsky, one of our directors, is the managing partner of Burnet, Duckworth & Palmer LLP, the law firm which renders legal services to us.

ADDITIONAL INFORMATION

Additional information relating to us can be found on SEDAR at *www.sedar.com* and on our website at *www.nuvistaenergy.com*. Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities issued and authorized for issuance under our equity compensation plans will be contained in our proxy materials relating to our annual Shareholder meeting to be held on May 7, 2019. Additional financial information is contained in our financial statements for the year ended December 31, 2019 and the related management's discussion and analysis.

For additional copies of this Annual Information Form and the materials listed in the preceding paragraphs, please contact:

NuVista Energy Corporation
2500, 525 – 8th Avenue SW
Calgary AB T2P 1G1
Tel: (403) 538-8500
Fax: (403) 538-8505

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Form 51-101F3

Management of NuVista Energy Ltd. ("**NuVista**") is responsible for the preparation and disclosure of information with respect to NuVista's oil and natural gas activities in accordance with securities regulatory requirements. This information includes reserves data which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated NuVista's reserves data. The report of the independent qualified reserves evaluator is presented below.

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

(a) reviewed NuVista'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 with management and the independent qualified reserves evaluator.

The Reserves Committee of the Board of Directors has reviewed NuVista's procedures for assembling and reporting other information associated with oil and natural 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 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 are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) "*Ronald J. Eckhardt*"
Ronald J. Eckhardt
Director and Chairman of the Reserves Committee

(signed) "*Jonathan A. Wright*"
Jonathan A. Wright
President and Chief Executive Officer

(signed) "*Keith A. MacPhail*"
Keith A. MacPhail
Chairman

(signed) "*Mike Lawford*"
Mike Lawford
Chief Operating Officer

March 3, 2020

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

Form 51-101F2

To the Board of Directors of NuVista Energy Ltd. (the "Company"):

2. We have evaluated the Company's reserves data as at December 31, 2019. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2019, estimated using forecast prices and costs.

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

4. 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).

5. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

6. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us 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:

Independent Qualified Reserves Evaluator	Effective Date of Evaluation Report	Location of Reserves (County or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate - $000s)			
			Audited	**Evaluated**	**Reviewed**	**Total**
GLJ Petroleum Consultants	Dec. 31, 2019	Canada	—	3,180,360	—	**3,180,360**

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

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

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

Executed as to our report referred to above:

GLJ Petroleum Consultants Ltd., Calgary, Alberta, Canada, February 6, 2020.

(signed) "*Kelly J. Zukowski*"
P. Eng., Manager, Engineering

APPENDIX C

NUVISTA ENERGY LTD.
MANDATE OF THE AUDIT COMMITTEE

Role and Objective

The Audit Committee (the "**Committee**") is a committee of the Board of Directors (the "**Board of Directors**") of NuVista Energy Ltd. ("**NuVista**") to whom the Board of Directors has delegated responsibility for oversight of the nature and scope of the annual audit, management's reporting on internal accounting standards and practices, financial information and accounting systems and procedures, financial reporting and statements and recommending, for Board of Directors approval, the audited financial statements and other mandatory disclosure releases containing financial information. The objectives of the Committee, with respect to NuVista and its subsidiaries, partnership and other controlled entities are as follows:

- To assist the directors in meeting their responsibilities (especially for accountability) in respect of the preparation and disclosure of the financial statements of NuVista and related matters;
- To provide better communication between directors and external auditors;
- To enhance the external auditor's independence;
- To increase the credibility and objectivity of financial reports; and
- To strengthen the role of the outside directors by facilitating in depth discussions between directors on the Committee, management and external auditors.

Membership of Committee

- The Committee shall be comprised of at least three directors, all of whom are "independent" (as such term is used in Multilateral Instrument 52-110 — Audit Committees ("**MI 52-110**").
- The Board of Directors shall have the power to appoint the Committee Chair and other members of the Committee.
- All of the members of the Committee shall be "financially literate". The Board of Directors has adopted the definition for "financial literacy" used in MI 52-110.

Meetings

- At all meetings of the Committee every question shall be decided by a majority of the votes cast. In case of an equality of votes, the Committee Chair shall not be entitled to a second or casting vote.
- A quorum for meetings of the Committee shall be a majority of its members, and the rules for calling, holding, conducting and adjourning meetings of the Committee shall be the same as those governing the Board of Directors.
- Meetings of the Committee should be scheduled to take place at least four times per year. Minutes of all meetings of the Committee shall be taken. The CEO and CFO shall attend meetings of the Committee, unless otherwise excused from all or part of any such meeting by the Committee Chair.
- The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board of Directors.

- The Committee shall meet with the external auditor at least once per year (in connection with the preparation of the year-end financial statements) and at such other times as the external auditor and the Committee consider appropriate.

Mandate and Responsibilities of Committee

- It is the responsibility of the Committee to oversee the work of the external auditors, including resolution of disagreements between management and the external auditors regarding financial reporting.

- It is the responsibility of the Committee to monitor, on behalf of the Board of Directors, NuVista's internal control systems, including:

    - identifying, monitoring and mitigating business risks; and

    - ensuring compliance with legal, ethical and regulatory requirements including the certification process.

- It is a primary responsibility of the Committee to review the annual and quarterly financial statements of NuVista prior to their submission to the Board of Directors for approval. The process should include but not be limited to:

    - reviewing the appropriateness of significant accounting principles and any changes in accounting principles, or in their application, which may have a material impact on the current or future years' quarterly unaudited and annual audited financial statements;

    - reviewing significant accruals, reserves or other estimates such as the impairment test calculation;

    - reviewing accounting treatment of unusual or non-recurring transactions;

    - ascertaining compliance with covenants under loan agreements;

    - reviewing the adequacy of the asset retirement obligation in the financial statements;

    - reviewing disclosure requirements for commitments and contingencies;

    - reviewing adjustments raised by the external auditors, whether or not included in the financial statements;

    - reviewing unresolved differences between management and the external auditors;

    - reviewing non-recurring transactions;

    - reviewing related party transactions; and

    - obtaining explanations of significant variances with comparative reporting periods.

- The Committee is to review the financial statements, prospectuses, management discussion and analysis (MD&A), annual information forms (AIF) and all public disclosure containing audited or unaudited financial information before release and prior to Board of Directors approval. The Committee must be satisfied that adequate procedures are in place for the review of NuVista's disclosure of all other financial information and shall periodically access the accuracy of those procedures.

- With respect to the appointment of external auditors by the Board of Directors, the Committee shall:

    - recommend to the Board of Directors the appointment of the external auditors;

  - recommend to the Board of Directors the terms of engagement of the external auditor, including the compensation of the auditors and a confirmation that the external auditors shall report directly to the Committee;

  - when there is to be a change in auditors, review the issues related to the change and the information to be included in the required notice to securities regulators of such change; and

  - review and approve any non-audit services to be provided by the external auditors' firm and consider the impact on the independence of the auditors.

- The Committee shall review with external auditors (and internal auditor if one is appointed by NuVista) their assessment of the internal controls of NuVista, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses. The Committee shall also review annually with the external auditors their plan for their audit and, upon completion of the audit, their reports upon the financial statements of NuVista and its subsidiaries.

- The Committee must pre–approve all non–audit services to be provided to NuVista or its subsidiaries by the external auditors. The Committee may delegate to one or more members the authority to pre–approve non–audit services, provided that the member report to the Committee at the next scheduled meeting such pre–approval and the member comply with such other procedures as may be established by the Committee from time to time.

- The Committee shall review financial risk management policies and procedures of NuVista (i.e. hedging, litigation and insurance).

- The Committee shall establish a procedure for:

  - the receipt, retention and treatment of complaints received by NuVista regarding accounting, internal accounting controls or auditing matters; and

  - the confidential, anonymous submission by employees of NuVista of concerns regarding questionable accounting or auditing matters.

- The Committee shall review and approve NuVista's hiring policies regarding employees and former employees of the present and former external auditors of NuVista.

- The Committee shall have the authority to investigate any financial activity of NuVista. All employees of NuVista are to cooperate as requested by the Committee.

- The Committee shall meet at least quarterly with the Chief Financial Officer, independent of other management and the external auditors. The issues for consideration should include, but are not limited to:

  - obtaining feedback on competencies, skill sets and performance of key members of the financial reporting team;

  - enquiring as to significant differences from prior year period audits or reviews;

  - enquiring as to transactions accounted for in an acceptable manner but on a basis which in the opinion of the external auditor, was not the preferable accounting treatment;

  - enquiring as to any differences between management and the external auditor;

  - enquiring as to material differences in accounting policies, disclosures or presentation from prior periods;

- enquiring as to deficiencies in internal controls identified in the course of the performance of the procedures by the Chief Financial Officer; and

- enquiring as to any other matters or observations that the external auditors would like to bring to the attention of the Committee.

- The Committee may retain persons having special expertise and/or obtain independent professional advice to assist in filling their responsibilities at the expense of NuVista without any further approval of the Board of Directors.

Reviewed and re-approved by the Board of Directors: March 3, 2020.

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