ANNUAL INFORMATION FORM
DATED MARCH 29, 2018

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 inv_rel@nuvistaenergy.com.

WHAT'S INSIDE

GLOSSARY OF TERMS

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 12, 2018 evaluating as of December 31, 2017, 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.

CONVENTIONS

Certain terms used herein are defined in the "*Glossary of 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	Tcf	trillion cubic feet
Mbbls	thousand barrels	Mcf/d	thousand cubic feet per day
MMbbls	million barrels	MMcf/d	million cubic feet per day
Mstb	thousand stock tank barrels of oil	MMbtu	million British Thermal Units
NGLs	natural gas liquids	GJ	gigajoule

Other	
AECO	the natural gas storage facility located at Suffield, Alberta, connected to TransCanada'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
MBoe	thousand barrels of oil equivalent
Mcfe	thousand cubic feet of gas equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one barrel of oil
MMBoe	million barrels of oil equivalent
Tcfe	trillion cubic feet equivalent
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
$MM	millions 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: "*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 of completion of the new SemCAMS gas plant, our commodity risk management program, our future exposure to AECO, and our long term strategy with respect to acceptable debt levels; "*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 and 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, future abandonment and reclamation costs, future developments costs, our ability to fund future developments costs through funds from operations 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 – Principal Oil and Natural Gas Properties*" as to our capital expenditure plans, exploration and development activities, anticipated land expiries, hedging and marketing policies and plans, processing and transportation arrangements and plans, reclamation and abandonment obligations, tax horizon, and drilling plans, "*Dividends*" as to our dividend policy and "*Description of our Capital Structure – Credit Facility"* as to the anticipated renewal of our Credit Facility.

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; and
- expected royalty rates and the anticipated benefits of royalty incentive programs.

Statements relating to "reserves" 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:

- volatility of commodity prices and differentials;
- weakness in the oil and gas industry;
- political uncertainty;
- liabilities inherent in oil and natural gas operations;
- lack of capacity and/or regulatory constraints on gathering and processing facilities, pipeline systems and railway lines;
- stock market volatility;
- incorrect assessments of the value of acquisitions;
- operational dependence on third parties;
- project risks;
- environmental risks;
- governmental regulation and regulatory changes;
- the inability to access sufficient capital from internal and external sources and the cost of capital;
- imprecision of reserve and resource estimates;
- competition from other industry participants;
- changes in our credit ratings;
- risks associated with our information technology systems and cyber-security;
- our ability to successfully implement new technologies into our operations;
- alternatives to and changing demand for petroleum products;
- 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;
- 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

Drilling Locations

We disclose drilling locations in this Annual Information Form in three categories: (i) proved locations; (ii) probable locations; and (iii) unbooked locations. Proved locations and probable locations are derived from the GLJ Reserve Report and account for drilling locations that have associated proved and/or probable reserves, as applicable. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources.

Of the 405 net drilling locations identified herein, 135 net are proved locations, 123 net are probable locations and 147 net are unbooked locations. Of the 36 gross Pipestone drilling locations described in this Annual Information Form, 9 are proved locations and 27 are probable locations. Of the 4 gross Lower Montney drilling locations described in the Annual Information Form, 2 are proved locations and 2 are probable locations.

Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information, based upon proximal NuVista and industry well results. There is no certainty that we will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or 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. While certain of the unbooked drilling locations have been derisked by drilling existing wells in relative close proximity to such unbooked drilling locations, other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves or production.

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, MMBoes, Mcfes and Tcfes may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl and an Mcfe conversion ratio of 1 Bbl:6 Mcf 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.**

NON-GAAP MEASURES

The term "netback" in this Annual Information Form is not a recognized measure under generally accepted accounting principles. 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 and is determined by deducting royalties, transportation charges and operating expenses from petroleum and natural gas revenue. Readers are cautioned; however, that this measure should not be construed as an alternative to net earnings or funds from operating activities determined in accordance with generally accepted accounting principles 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 Alberta Deep Basin (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 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. Since then, we have grown our business through a combination of exploration, development and optimization of our assets.

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 2015 for aggregate gross proceeds of $26.9 million. Total average production associated with these assets was approximately 345 Boe/d.

We disposed of various non-core assets throughout 2016 for aggregate gross proceeds of $76.0 million. Total average production associated with these assets was approximately 3,450 Boe/d. Included in divestitures in 2016 was the June 17, 2016 divestiture of our W6 Sweet Cretaceous (non-Montney) natural gas assets in the Wapiti area south of Grande Prairie in exchange for $70 million in cash (before adjustments) together with certain Wapiti area Montney lands. The proceeds from the dispositions were used to reduce bank indebtedness.

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.

Equity Offerings

On April 29, 2015, we completed a public offering with a syndicate of underwriters of an aggregate of 11,465,000 Common Shares at $7.85 per Common Share and 2,313,000 Common Shares issued on a "flow-through" basis with respect to Canadian development expense at $8.65 per Common Share for gross proceeds of $110.0 million. In addition, we completed a non-brokered private placement of 231,040 Common Shares issued on a "flow-through" basis with respect to Canadian development expense at $8.65 per Common Share for gross proceeds of $2.0 million.

On June 28, 2016, we completed a private offering of 3,252,411 Common Shares, for gross proceeds of approximately $21.5 million. The Common Shares were issued on a "flow-through" basis in respect of Canadian development expense at a price of $6.65 per Common Share. Of the total Common Shares issued, 92,000 Common Shares were acquired by certain of our directors, officers and employees on a non-brokered, "flow through" basis on the same terms.

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.

Senior Unsecured Notes

On June 22, 2016, we completed a private placement of $70 million principal amount of the 2021 Notes. The proceeds from the sale of the 2021 Notes were used to reduce bank indebtedness.

On March 2, 2018, we issued $220.0 million aggregate principal amount of the 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

In November 2015, our lenders reconfirmed the borrowing base of our Credit Facility at $300 million.

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 July 1, 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 Facility agreement to modify our ability to enter into basis swap hedges.

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

Management and Board of Directors

On June 30, 2015, Mr. Craig Burton, our Vice President, Business Development & New Plays resigned. His position was not replaced and the business development role was transferred to the Vice President, Land.

On August 9, 2016, Ms. Deborah Stein joined our Board. On November 14, 2016, Ms. Stein was appointed Chair of the Audit Committee.

On November 14, 2016, Mr. Peter Comber retired from our Board.

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.

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 results.

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

- 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 upon safe operations and the minimization of our environmental impact.

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 99% 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 189 gross sections (171 net) of land with an approximate working interest of 90%. Currently, over 99% of our production is located in the Wapiti Montney. We have an inventory of approximately 405 net drilling locations, which includes Montney intervals with current production or with direct offset production. Based on our current drilling pace, this provides for approximately 20 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 30% to 33% condensate in BOE terms. As result, our condensate revenue comprised approximately 58% of our total oil and gas revenues in 2017. 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 currently produce from three main areas of the Wapiti Montney – Bilbo, Elmworth and Gold Creek - and have plans to develop our Pipestone area in the next couple of years.

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 lateral lengths can be in excess of 3,800 metres and can contain over 80 frac stages. These improvements 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 just over27 days in 2017.

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. The compressor station located in our Bilbo block has productive capacity of approximately 18,000 Boe/d while our Elmworth area compressor station has a capacity of approximately 18,000 Boe/d. Both of these compressors are currently being gradually pushed beyond nameplate capacity with good initial success. The vast majority of our production is processed through two large sour gas plants, Keyera Simonette and SemCams K3. We have entered into long term processing agreements at each of these plants. We have also contracted for capacity as anchor tenant in a new gas plant that is currently under construction by SemCams. This plant is expected to be operational by early to mid-2019 and will further reduce our operating costs due to the close proximity of the plant to our lands. See "*Other Oil and Natural Gas Information – Marketing Arrangements*" and *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 recent AECO pricing.

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 funds from operations 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, subject to a maximum volume of up to 100,000 MMbtu/day and with a term of less than 7 years from the date any such swap is entered into, that are now 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. Fixed price hedges are customarily done in Canadian dollars however at times they may be done in US dollars and can be closed to Canadian dollars using an exchange rate hedge at a later date.

As a result of our pipeline transportation agreements and strong hedge position, our exposure to AECO pricing is mitigated significantly as we receive the price at various North American markets. In 2018, our expected exposure to AECO prices is less than 1%.

Solid Balance Sheet and Liquidity Position

Our long term strategy is to maintain a net debt to annualized current quarter funds from operations 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 funds from operations ratio of around 2x.

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 oil and natural gas production. Oil 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 oil 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. 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 requirements established for the oil and gas industry. We 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 2017, expenditures for abandonment and reclamation costs, including costs to reclaim and abandon ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities, were $10 million.

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.

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially affected in the remainder of 2018 by the renegotiation or termination of contracts or subcontracts other than with respect to our Credit Facility which has an annual renewal date of April 27, 2018. See "*Risk Factors – Credit Facility Arrangements* ".

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, 2017, we employed 66 full-time employees, including 58 office and 8 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 January 31, 2018. The statement is effective as of December 31, 2017 and the preparation date of the statement is January 23, 2018. 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, 2017, 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, 2017 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 for our wells with attributable reserves. 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, 2017 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	2	2	465	419	18,254	14,305	214,673	198,851
Developed Non-Producing	24	23	177	165	2,350	1,871	26,729	24,394
Undeveloped	-	-	-	-	36,854	30,815	437,149	398,727
TOTAL PROVED	25	25	642	585	57,458	46,990	678,551	621,973
TOTAL PROBABLE	8	8	194	177	59,996	46,427	695,801	615,084
TOTAL PROVED PLUS PROBABLE	34	33	836	761	117,454	93,418	1,374,351	1,237,056

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	778,436	627,270	529,549	463,144	415,557	11.14	1.86
Developed Non-Producing	126,190	92,125	72,607	60,256	51,799	12.13	2.02
Undeveloped	1,112,436	611,997	349,014	199,444	108,352	3.59	0.60
TOTAL PROVED	2,017,062	1,331,392	951,170	722,844	575,709	6.31	1.05
TOTAL PROBABLE	2,837,043	1,430,985	830,939	531,658	363,117	5.58	0.93
TOTAL PROVED PLUS PROBABLE	4,854,104	2,762,377	1,782,109	1,254,503	938,826	5.95	0.99

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	778,436	627,270	529,549	463,144	415,557
Developed Non-Producing	126,190	92,125	72,607	60,256	51,799
Undeveloped	847,413	475,392	272,076	152,978	78,704
TOTAL PROVED	1,752,039	1,194,786	874,232	676,379	546,061
TOTAL PROBABLE	2,062,763	1,027,292	583,542	363,860	241,747
TOTAL PROVED PLUS PROBABLE	3,814,801	2,222,079	1,457,774	1,040,238	787,808

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2017 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)	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
TOTAL PROVED	6,768,709	854,799	2,784,938	1,052,063	59,848	2,017,062	265,023	1,752,039
TOTAL PROVED PLUS PROBABLE	14,929,607	2,186,689	5,769,727	2,012,018	107,069	4,854,104	1,039,303	3,814,801

Notes:

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

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

PRODUCT TYPE (1)	FUTURE NET REVENUE BY PRODUCT TYPE AS OF DECEMBER 31, 2017 FORECAST PRICES AND COSTS NET PRESENT VALUE OF FUTURE NET REVENUE (3)(4) (before deducting Future Income Tax Expenses and Discounted at 10%/year) (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)	343	7.88	1.31
Heavy Oil (1)	28	30.65	5.11
Shale Gas (2)	950,799	6.31	1.05
TOTAL PROVED	951,170	6.31	1.05
PROVED PLUS PROBABLE			
Light and Medium Crude Oil (1)	476	8.33	1.39
Heavy Oil (1)	43	28.94	4.82
Shale Gas (2)	1,781,591	5.94	0.99
TOTAL PROVED PLUS PROBABLE	1,782,109	5.95	0.99

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas. Conventional and coal bed methane gas values are included in this total due to the relative immateriality of these components.
(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 and natural gas 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)

YEAR	OIL				NATURAL GAS		NATURAL GAS LIQUIDS			INFLATION RATES (2) %/Year	EXCHANGE RATE (3) ($US/ $Cdn)
	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Hardisty Heavy 12° API ($Cdn/Bbl)	Cromer Medium 29. 0° API ($Cdn/Bbl)	AECO Natural Gas Price ($Cdn/ MMbtu)	NYMEX Gas ($US/ MMbtu)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	Edmonton C5+ Stream Quality ($/Bbl)		
Forecast											
2018	59.00	70.25	39.63	65.34	2.20	2.85	40.40	53.74	76.42	2.0	0.790
2019	59.00	70.25	45.71	65.34	2.54	3.00	36.53	49.18	74.68	2.0	0.790
2020	60.00	70.31	49.81	65.39	2.88	3.25	35.93	49.22	74.38	2.0	0.800
2021	63.00	72.84	52.89	67.74	3.24	3.50	36.06	50.99	77.16	2.0	0.810
2022	66.00	75.61	55.89	70.32	3.47	3.70	36.29	52.93	79.88	2.0	0.820
2023	69.00	78.31	58.82	72.83	3.58	3.86	37.59	54.82	82.53	2.0	0.830
2024	72.00	81.93	62.43	76.19	3.66	3.94	39.33	57.35	86.14	2.0	0.830
2025	75.00	85.54	66.05	79.55	3.73	4.02	41.06	59.88	89.76	2.0	0.830
2026	77.33	88.35	68.86	82.16	3.80	4.10	42.41	61.84	92.57	2.0	0.830
2027	78.88	90.22	70.72	83.90	3.88	4.18	43.30	63.15	94.43	2.0	0.830
2028+	+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	0.830

Notes:

(1) As at January 1, 2018.

(2) Inflation rate for costs.

(3) 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, 2017, excluding financial derivative commodity contracts were $3.58/Mcf for natural gas, $61.01/Bbl for condensate and oil, and $24.42/Bbl for NGLs (excluding condensate).

Reserves Reconciliation

	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, 2016	65	21	86	8,339	2,724	11,062
Discoveries	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(1)	1	-	454	(299)	156
Acquisitions	-	-	-	-	-	-
Dispositions	(33)	(13)	(46)	(6,486)	(2,142)	(8,628)
Economic Factors	(2)	(1)	(2)	(113)	(88)	(201)
Production	(4)	-	(4)	(1,556)	-	(1,556)
December 31, 2017	25	8	34	639	194	833

	NATURAL GAS LIQUIDS			SHALE GAS		
	PROVED (Mbbls)	PROBABLE (Mbbls)	PROVED PLUS PROBABLE (Mbbls)	PROVED (MMcf)	PROBABLE (MMcf)	PROVED PLUS PROBABLE (MMcf)
December 31, 2016	42,587	39,668	82,255	538,704	500,351	1,039,055
Discoveries	-	-	-	-	-	-
Extensions	16,480	18,578	35,058	161,428	171,417	332,845
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	4,411	1,407	5,818	28,492	23,888	52,380
Acquisitions	-	-	-	-	-	-
Dispositions	(566)	(362)	(928)	(5,704)	(4,063)	(9,767)
Economic Factors	(1,167)	704	(463)	(6,437)	4,207	(2,230)
Production	(4,286)	-	(4,286)	(37,933)	-	(37,933)
December 31, 2017	57,458	59,996	117,454	678,551	695,801	1,374,351

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 nine 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)		HEAVY CRUDE OIL (Mbbls)		SHALE GAS (MMcf)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2015	-	29	-	-	72,522	303,946
2016	-	29	-	-	72,632	357,977
2017	-	-	-	-	111,664	437,149

	CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2015	-	9,045	5,192	23,128
2016	-	1,245	5,851	28,036
2017	-	-	11,396	36,854

Of our total proved plus probable gross reserves, 109,712 MBoe or 32% 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 109,712 MBoe or 100% of our proved undeveloped reserves. Subject to market conditions, capital expenditures of $165.7 million in 2018 and $171.8 million in 2019 will be invested in developing our proved undeveloped reserves. The remaining proved undeveloped reserves are planned to be mostly developed within an additional three year time period 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)		HEAVY CRUDE OIL (Mbbls)		SHALE GAS (MMcf)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2015	-	12	-	-	136,609	461,758
2016	-	12	-	-	60,889	436,348
2017	-	-	-	-	224,521	606,839

	CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2015	5,507	38,105	10,218	36,905
2016	-	389	6,300	34,599
2017	-	-	24,767	52,818

Of our total proved plus probable reserves, 153,958 MBoe or 44% are probable 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 153,958 MBoe or 100% of our probable undeveloped reserves. Subject to market conditions, capital expenditures of $59.9 million in 2018 and $133.9 million in 2019 will be invested developing our probable undeveloped reserves. The remaining probable undeveloped reserves are planned to be mostly developed within an additional seven year time period 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 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 "*Marketing Arrangements*". 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 liability issues 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 issues, and opportunities for multi-location programs to reduce costs.

As at December 31, 2017, we had approximately 1,000 net wells for which we expect to incur abandonment and reclamation costs. We calculated our overall abandonment costs at $76 million (undiscounted) and $29 million (10% discount). Included in this calculation are the abandonment and reclamation costs for our proved plus probable properties as well as surface leases, facilities and pipelines. The future net revenues disclosed in this Annual Information Form based on the GLJ Reserve Report do not contain an allowance for abandonment and reclamation costs for surface leases, facilities and pipelines. The GLJ Reserve Report deducted $60 million (undiscounted proved) and $3 million (10% discount using forecast prices and costs) for abandonment costs of wells with booked reserves, 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)
2018	173,900	233,828
2019	173,971	307,873
2020	355,028	382,029
2021	172,228	251,606
2022	176,935	267,535
Remaining	-	569,147
Total (Undiscounted)	1,052,063	2,012,018

We expect to fund the development costs of our reserves through a combination of internally generated funds from operations, 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 funds from operations. 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, 2017. 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 520 kilometers northwest of Calgary. This operating area continues to play the fundamental role in our future growth with substantially all our projected 2018 capital budget expected to be spent in this region.

We hold Montney rights in approximately 120,960 gross acres (109,440 net acres) of land with an approximate 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.

In 2014, we completed the construction of a 100% owned compressor and dehydration station in the Bilbo area. The facility and downstream third party infrastructure has a gross throughput capacity of up to 80 MMcf/d. A second compressor station was constructed in the Elmworth area and became operational in June 2015. The facility at Elmworth was expanded to 80 MMcf/d of throughput capacity in 2017. Production from the Wapiti Montney zone is currently processed at one of three large area processing plants: the SemCAMS K3 plant, the Keyera Simonette plant and the CNRL Gold Creek plant.

In 2017, we drilled and completed 30 (30 net) wells resulting in 29 (29 net) condensate-rich natural gas wells and one seismic monitoring well. A combination of development pad drilling and delineation drilling took place in 2017. 2018 activity will focus on maximizing production volumes at Gold Creek, Bilbo and Elmworth and a modest amount of delineation drilling.

We currently produce from three main areas of the Wapiti Montney – Bilbo, Elmworth and Gold Creek and have plans to develop our Pipestone area in the next couple of years. In 2017, Wapiti Montney production averaged 28,900 BOE/d (105.0 MMcf/d of natural gas, 9,600 Bbls/d of condensate and 1,800 Bbls/d of natural gas liquids (excluding condensate).

Non-core Areas

We also have non-core operations in three additional areas of Alberta whose combined production in 2017 averaged 900 BOE/d compared to 2,761 BOE/d in 2016 due to asset divestitures and production decline. Substantially all of the 2017 average non-core production comprised of natural gas. These operating regions combined gross acreage in 2017 is 125,380 gross acres (102,240 net acres). We are not anticipating spending any development capital in 2018 and did not drill any wells in these regions in 2017 or 2016.

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, 2017.

	OIL WELLS				NATURAL GAS WELLS			
	PRODUCING		NON-PRODUCING [2]		PRODUCING		NON-PRODUCING [2]	
	GROSS	NET	GROSS	NET	GROSS	NET	GROSS	NET
Alberta [1]	10.0	3.2	127.0	101.1	277.0	209.8	863.0	692.0

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 54 gross (38.2 net) oil wells and 465 gross (362.4 net) natural gas wells that are abandoned but not yet reclaimed.

Properties With No Attributed Reserves

As at December 31, 2017 we held 313,426 gross acres (255,595 net acres) to which no reserves are currently attributed. Rights to explore, develop and exploit 41,149 net acres of these land holdings could expire by December 31, 2018 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 "*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 "*Marketing Arrangements*" below. For details of our material commitments to sell natural gas and crude oil which were outstanding as at December 31, 2017 see Note 17 to our financial statements for the year ended December 31, 2017.

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	2018 - 2022	2023 - 2034	2018 - 2022	2023 - 2034
Natural Gas (MMcf/d)	57	61	-	-
Condensate & NGL/s (Bbl/d)	-	449	-	-
Estimated Cost (millions)	$26	$165	$-	$2

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, 2017 see Note 20 to our financial statements for the year ended December 31, 2017.

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, 2018 to June 30, 2019 and up to 60% for July 1, 2019 to December 31, 2020 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 100,000 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 $3.58/Mcf for the year ended December 31, 2017.

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 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 is anticipated to commence in 2018 after the Sundre Crossover project is 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 LTFP 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, 2018 to June 30, 2019, up to 60% for the next 18 months and up to 30% for the following 24 months. In 2017, our average realized condensate & oil price (excluding financial derivative commodity contracts) was $61.01/Bbl and our average realized price for natural gas liquids (excluding condensate) was $24.42/Bbl. For additional details on our price risk management program see Note 17 to our financial statements for the year ended December 31, 2017.

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. With this agreement, we and SemCams have moved past Final Investment Decision. Both parties have received all board approvals needed to proceed with construction of the licensed gas plant. We will supply gas to this contract from the Gold Creek, Pipestone, Elmworth, and surrounding areas. Bilbo and adjacent southern lands will continue to be processed at the Keyera Simonette gas plant. When added to our existing capacity, this agreement will expand our total Wapiti area firm processing capacity to approximately 277 MMcf/d of raw gas by 2021. We intend to continue to pursue other processing and transportation agreements as we develop our Wapiti Montney play to provide line-of-sight to future capacity and production growth.

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 2018 funds from operations and capital expenditures, and existing tax pools, we do not expect to be cash taxable in 2018. Projecting taxability beyond 2018 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, 2017:

EXPENDITURE	YEAR ENDED DECEMBER 31, 2017 ($000s)
Property acquisition costs – Unproved properties (1)	510
Property acquisition costs – Proved properties	-
Exploration costs (2)	5,201
Development costs (3)	308,077
Other	1,514
Total	315,302

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.

Exploration and Development Activities

In 2017, we drilled 29 (100% interest) condensate-rich natural gas development wells within our Wapiti Montney resource play. We did not participate in any other exploratory or development wells in 2017.

In 2018, we expect to drill approximately 24 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 Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2018, 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	1	278	14,654	137,832	37,673
Total Proved plus Probable	1	281	16,588	158,577	43,066

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

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 2017				YEAR ENDED DEC 31, 2017
	MAR. 31	JUNE 30	SEPT. 30	DEC. 31	
Average Daily Production					
Light and Medium Crude Oil (Bbls/d)	18	6	18	2	11
Natural Gas (Mcf/d))	99,715	91,623	109,343	131,703	108,187
NGLs (Bbls/d) (1)	1,758	1,501	1,908	2,397	1,893
Condensate (Bbls/d) (1)	8,335	8,675	9,255	13,084	9,849
Combined (Boe/d)	26,731	25,454	29,405	37,435	29,783
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	43.35	12.88	4.27	2.23	5.13
Natural Gas ($/Mcf)	3.75	3.72	3.48	3.44	3.58
NGLs ($/Bbl) (1)	17.92	22.93	21.81	32.09	24.42
Condensate ($/Bbl) (1)	63.51	57.27	51.98	68.36	61.03
Combined ($/Boe)	35.01	34.28	30.72	38.04	34.75
Royalties Paid					
Light and Medium Crude Oil ($/Bbl)	3.61	12.88	4.27	2.23	5.13
Natural Gas ($/Mcf) (5)	(0.05)	(0.11)	(0.08)	(0.07)	(0.08)
NGLs ($/Bbl) (1)	1.43	1.60	1.78	1.37	1.54
Condensate ($/Bbl) (1)	3.95	3.86	3.29	4.44	3.94
Combined ($/Boe)	1.13	1.02	0.85	1.38	1.12
Production Costs (2)(3)					
Light and Medium Crude Oil ($/Bbl)	0.01	0.00	0.01	0.00	0.00
Natural Gas ($/Mcf)	1.11	1.07	1.06	0.94	1.04
NGLs ($/Bbl) (1)	0.70	0.63	0.67	0.62	0.65
Condensate ($/Bbl) (1)	3.34	3.63	3.23	3.37	3.39
Combined ($/Boe)	10.72	10.66	10.26	9.65	10.25
Transportation Costs					
Light and Medium Crude Oil ($/Bbl)	2.45	2.44	0.45	1.12	1.34
Natural Gas ($/Mcf)	0.54	0.64	0.64	0.62	0.61
NGLs ($/Bbl) (1)	0.00	0.00	0.00	0.00	0.00
Condensate ($/Bbl) (1)	1.56	2.38	0.45	1.12	1.33
Combined ($/Boe)	2.51	3.13	2.51	2.57	2.66
Netback Received (4)					
Light and Medium Crude Oil ($/Bbl)	37.28	39.25	25.52	57.84	34.00
Natural Gas ($/Mcf)	2.15	2.15	2.15	2.15	2.15
NGLs ($/Bbl) (1)	15.79	15.79	15.79	15.79	15.79
Condensate ($/Bbl) (1)	54.66	47.40	45.01	59.43	52.37
Combined ($/Boe)	20.65	19.47	17.10	24.44	20.72

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.

(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, 2017:

	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	-	1,879	9,829	103,925	29,028
Non-core	11	14	20	4,262	755
Total	11	1,893	9,849	108,187	29,783

Note:

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

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.

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 $285 million extendible revolving line of credit and a $25 million operating line of credit (collectively, the "**Credit Facility**"). The Credit Facility revolves for a one year period and, with the consent of lenders holding at least $66^{2/3}$% of the commitment amounts under the Credit Facility, may be extended for a period of up to one year. The current maturity date for the Credit Facility is April 27, 2018. If not extended by any or all lenders, the commitments of such non-extending lenders under the Credit Facility will cease to revolve, all outstanding advances thereunder owing to such non-extending lenders will become repayable in one year from the term date and the margins owing on such outstanding advances will increase by 0.50%. 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 1.00 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 2.00 percent to 3.50 percent depending upon our senior funded debt to EBITDA ratio calculated at our previous quarter end.

As at December 31, 2017, 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 0.50 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 renewal. At December 31, 2017, we had issued letters of credit totaling $13.2 million. The effective interest rate per annum on our borrowings under our Credit Facility for the twelve months ended December 31, 2017 was 3.0% 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

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.

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
2017			
January	7.15	6.3	9,190,792
February	6.83	5.82	8,837,879
March	6.39	5.33	10,478,689
April	7.10	6.06	11,850,992
May	7.73	5.91	15,056,570
June	7.09	6.08	6,394,731
July	6.84	5.91	8,588,855
August	6.72	6.03	5,849,691
September	8.02	6.43	9,935,592
October	8.16	6.83	10,696,535
November	8.87	7.58	12,147,194
December	8.63	7.51	6,644,451
2018			
January	9.16	7.65	9,795,193
February	8.83	7.14	10,064,997
March (1 - 28)	8.04	6.78	11,678,504

Prior Sales

During the year ended December 31, 2017, we issued a total of 1.0 million options pursuant to our stock option plan and 0.2 million restricted share awards pursuant to our restricted share award plan. No funds are received by us until the options are exercised. On the payment date of the restricted share awards, we have the sole discretion as to whether the awards shall be paid in cash, Common Shares from treasury or Common Shares purchased on the Toronto Stock Exchange. See note 15 of our financial statements for the year ended December 31, 2017 for a summary of stock option and restricted share award transactions.

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)(5) Calgary, Alberta	Chairman and Director	May 2003	Our Chairman and Chair of Bonavista Energy Corporation.
Ronald J. Eckhardt (2) Calgary, Alberta	Director	March 2013	Former Executive Vice-President, North American Operations for Talisman Energy Inc.
Pentti O. Karkkainen (1)(3)(6) West Vancouver, British Columbia	Director	July 2003	Former General Partner, KERN Partners Ltd. (a private equity firm and partnership).
Ronald J. Poelzer (1)(4)(5) Calgary, Alberta	Director	May 2003	Vice Chair of Bonavista Energy Corporation.
Brian G. Shaw (1) Toronto, Ontario	Director	August 2014	Director of Encana Corp., Manulife Bank of Canada and Manulife Trust Company.
Sheldon B. Steeves (2)(4) Calgary, Alberta	Director	March 2013	Former CEO and Chairman of Echoex Ltd., a private oil and natural gas exploration and production company.
Deborah S. Stein (1) Heritage Pointe, Alberta	Director	August 2016	Former Executive Vice President at AltaGas Ltd. From 2008 to 2015. Ms. Stein was Senior Vice President Finance and Chief Financial Officer of AltaGas Ltd.
Grant A. Zawalsky (4)(5) Calgary, Alberta	Director	May 2003	Managing Partner of Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Jonathan A. Wright (5) 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 McDavid Calgary, Alberta	Vice President, Development & Engineering	August 2006	Our Vice President, Development & Engineering since December 5, 2017. Prior thereto, our Vice President, Operations.
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 6, 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 Compensation Committee.
(4) Member of our Governance and Nominating Committee.
(5) Member of our Executive Committee.
(6) 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, approximately 7.1 million Common Shares or approximately 4.1% 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. MacPhail who was formerly a director of The Resort at Copper Point Ltd. (a private real estate development company) which was placed in receivership in February 2009 and 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.

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: Independent Businesswoman

Ms. Stein has over 30 years of industry experience, including 17 years of direct experience in the oil and gas business, most recently having held the position of 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 Parkland Fuel Corporation, Trican Well Service Ltd., Velvet Energy Ltd., CEDA and Past Chair of Financial Executives Canada.

Ms. Stein is a 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 and a Masters of Business Administration degree from Queen's University in Kingston.

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 Encana Corp., 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 Chairman 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] ($)	ALL OTHER FEES [4] ($)
2017	279,000	35,000	350	-
2016	314,000	55,000	9,205	-

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.
(4) Represents fees billed for products and services provided by our auditors other than the other services reported.

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 where the companies have assets or operations. While these regulations do not affect our operations in any manner that is materially different than they affect other similarly-sized industry participants with similar assets and operations, investors should consider such regulations carefully. Although governmental legislation is a matter of public record, we are unable to predict what additional legislation or amendments governments may enact in the future.

We have interests in crude oil and natural gas properties, along with related assets, primarily in the Canadian province of Alberta. Our assets and operations are regulated by administrative agencies deriving authority from underlying legislation. 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 (vi) 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 provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions. The discussion below outlines certain pertinent conditions and regulations that impact the crude oil and natural gas industry in Western Canada.

Pricing and Marketing in Canada

Crude Oil

Producers of crude oil are entitled to negotiate sales contracts directly with crude oil purchasers, which results in the market determining the price of crude oil. Worldwide supply and demand factors primarily determine 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

The price of natural gas sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. 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 price of condensate and other natural gas liquids such as ethane, butane and propane ("**NGLs**") sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such price depends, 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

Crude oil, natural gas and NGLs exports from Canada are subject to the *National Energy Board Act* (Canada) (the "**NEB Act**") and the *National Energy Board Act Part VI (Oil and Gas) Regulation* (the "**Part VI Regulation**"). The NEB Act and the Part VI Regulation authorize crude oil, natural gas and NGLs exports under either short-term orders or long-term licences. To obtain a crude oil export licence, a mandatory public hearing with the National Energy Board (the "**NEB**") is required, which is no longer the case for natural gas and NGLs. For natural gas and NGLs, the NEB uses a written process that includes a public comment period for impacted persons. Following the comment period, the NEB completes its assessment of the application and either approves or denies the application. For natural gas, the maximum duration of an export licence is 40 years and, for crude oil and other gas substances (e.g. NGLs), the maximum term is 25 years. All crude oil, natural gas and NGLs licences require the approval of the cabinet of the Canadian federal government.

Orders from the NEB provide a short-term alternative to export licences and may be issued more expediently, since they do not require a public hearing or approval from the cabinet of the Canadian federal government. 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 other criteria prescribed by the NEB 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 or other transportation projects are underway, many contemplated projects have been cancelled or are delayed due to regulatory hurdles, court challenges and economic and political factors. The transportation capacity deficit is not likely to be resolved quickly given the significant length of time required to complete major pipeline or other transportation projects 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.

Pursuant to the draft legislation introduced by the Government of Canada on February 8, 2018, if enacted the NEB will be replaced by the Canadian Energy Regulator ("**CER**") who will take on the NEB's responsibilities with respect to exports of crude oil, natural gas and NGL exports from Canada; however, at the present time it is not proposed that the legislative regime relating to exports of crude oil, natural gas and NGL exports from Canada will substantively change under the new regime.

Transportation Constraints and Market Access

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

Developing a strong network of transportation infrastructure for crude oil, natural gas and NGLs, including by means of pipelines, rail, marine and trucks, in order to obtain better access to domestic and international markets has been a significant challenge to the Canadian crude oil and natural gas industry. Improved means of access to global markets, especially the Midwest United States and export shipping terminals on the west coast of Canada, would help to alleviate the pressures of pricing discussed. Several proposals have been announced to increase pipeline capacity out of Western Canada, to reach Eastern Canada, the United States and international markets via export shipping terminals on the west coast of Canada. While certain projects are proceeding, the regulatory approval process as well as economic and political factors for transportation and other export infrastructure has led to the delay of many pipeline projects or their cancellation altogether.

Under the Canadian constitution, interprovincial and international pipelines fall within the federal government's jurisdiction and require approval by both the NEB and the cabinet of the federal government. However, recent years have seen a perceived lack of policy and regulatory certainty at a federal level. Although the current federal government recently introduced draft legislation to amend the current federal approval processes, it is uncertain when the new legislation will be brought into force and whether any changes to the draft legislation will be made before the legislation is brought into force. It is also uncertain whether any new approval process adopted by the federal government will result in a more efficient approval process. The lack of regulatory certainty is likely to have an influence on 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 as well as court challenges on various issues such as indigenous title, the government's duty to consult and accommodate indigenous peoples and the sufficiency of environmental review processes, which creates further uncertainty. Export pipelines from Canada to the United States face additional uncertainty as such pipelines require approvals of several levels of government in the United States.

Natural gas prices in Alberta and British Columbia have also been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. While 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, other companies 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.

Additionally, while a number of liquefied natural gas export plants have been proposed for the west coast of Canada, 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.

The North American Free Trade Agreement and Other Trade Agreements

The North American Free Trade Agreement ("**NAFTA**") among the governments of Canada, the United States and Mexico came into force on January 1, 1994. Under the terms of NAFTA, 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.

In 2017, the United States government announced its intention to renegotiate NAFTA. As a result, Canada, the United States and Mexico began renegotiating the terms of NAFTA in mid-2017. The United States has also suggested that it might give notice of the termination of NAFTA if it is not satisfied with the outcome of the renegotiations. If the United States does give notice of its intent to terminate or withdraw from NAFTA, the earliest such termination or withdrawal could occur would be six months after such notice is given. The renegotiations are still underway and the outcome of such negotiations remain unclear, but as the United States remains by far Canada's largest trade partner and the largest international market for the export of crude oil, natural gas and NGLs from Canada, any changes to, or termination of, NAFTA could have an impact on Western Canada's crude oil and natural gas industry at large, including our business.

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 oil and gas products to the European Union. Although CETA remains subject to ratification by certain national legislatures in the European Union, provisional application of CETA commenced on September 21, 2017. In addition, Canada and ten other countries recently concluded discussions and agreed on the draft 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 text of CPTPP has not been finalized or published and the agreement remains subject to ratification by the governments of each of the countries involved. While it is uncertain what effect CETA, CPTPP or any other trade agreements will have on the oil and gas industry in Canada, the lack of available infrastructure for the offshore export of oil and gas may limit the ability of Canadian oil and 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. The 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.

Alberta has 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 the province of Alberta. In the provinces of Alberta, approximately 19% 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.

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 governmental regulation and are generally calculated as a percentage of the value of gross production. The rate of royalties payable generally depends in part on prescribed reference prices, well productivity, geographical 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 are often 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.

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

Alberta

In Alberta, the provincial government royalty rates apply to Crown-owned mineral rights. In 2016, Alberta adopted a modernized Alberta royalty framework (the "**Modernized Framework**") that applies to all wells drilled after January 1, 2017. 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 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% 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.

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 also required to pay annual rental payments, at a rate of $3.50 per hectare, and make monthly royalty payments in respect of crude oil and natural gas produced.

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

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

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

Freehold and Other Types of Non-Crown Royalties

Royalties on production from privately-owned freehold lands are negotiated between the mineral freehold owner and the lessee under a negotiated lease or other contract.

In addition to the royalties payable to the mineral owners, 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.

IOGC is a special agency responsible for managing and regulating the crude oil and natural gas resources located on indigenous reservations across Canada. IOGC's responsibilities include negotiating and issuing the crude oil and natural gas agreements between indigenous groups and crude oil and natural gas companies, as well as collecting royalty revenues on behalf of indigenous groups and depositing the revenues in their trust accounts. While certain standards exist, 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 terms.

Regulatory Authorities and Environmental Regulation

General

The 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 and facility sites. Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability and the imposition of material fines and penalties. In addition to these specific, known requirements, future changes to environmental legislation, including anticipated legislation for air pollution and greenhouse gas ("**GHG**") emissions, 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. However, such conflicts are uncommon. 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 June 20, 2016, the federal government launched a review of current environmental and regulatory processes. On February 8, 2018, the Government of Canada introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with the CER. Pursuant to the draft legislation, the Impact Assessment Agency of Canada (the "**Agency**") would replace the Canadian Environmental Assessment Agency. It appears that additional categories of projects may be included within new impact assessment process, such as large-scale wind power facilities and in-situ oilsands facilities. The revamped approval process for applicable major developments will have specific legislated timelines at each stage of the formal impact assessment process. The Agency's process would focus on: (i) early engagement by proponents to engage the Agency and all stakeholders such as the public and indigenous groups prior to the formal impact assessment process; (ii) potentially increased public participation where the project undergoes a panel review; (iii) providing analysis of the potential impacts and effects of a project without making recommendations, to support a public-interest approach to decision-making, with cost-benefit determinations and approvals made by the

Minister of Environment and Climate Change or the cabinet of the federal government; (iv) analyzing further specified factors for projects such as alternatives to the project and social and indigenous issues in addition to health, environmental and economic impacts; and (v) overseeing an expanded follow-up, monitoring and enforcement process with increased involvement of indigenous peoples and communities. As to the proposed CER, many of its activities would be similar to the NEB, albeit with a different structure and the notable exception that the CER would no longer have primary responsibility in the consideration of the new major projects, instead focusing on the lifecycle regulation (e.g. overseeing construction, tolls and tariffs, operations and eventual winding down) of approved projects, while providing for expanded participation by communities and indigenous peoples. It is unclear when the new regulatory scheme will come into force or whether any amendments will be made prior to coming into force. Until then, the federal government's interim principles released on January 27, 2016 will continue to guide decision-making authorities for projects currently undergoing environmental assessment. The eventual effects of the proposed regulatory scheme on proponents of major projects remains unclear.

On May 12, 2017, the federal government introduced the *Oil Tanker Moratorium Act* 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 is still considering the bill, which passed second reading on October 4, 2017. If implemented, the legislation may prevent the building of pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium and, as a result, negatively affect the ability of producers to access global markets.

Alberta

The AER is the single regulator responsible for all resource development in Alberta. 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 Alberta 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 Alberta Environment and Parks, Alberta Energy, the Policy Management Office, 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 and others are in the process of being implemented. These regional plans may affect further development and operations in such regions.

Liability Management Rating Program

Alberta

The AER administers the Licensee Liability Rating Program (the "**AB LLR Program**"). The AB LLR Program is a liability management program governing most conventional upstream crude oil and natural gas wells, facilities and pipelines. Alberta's *Oil and Gas Conservation Act* (the "**OGCA**") establishes an orphan fund (the "**Orphan Fund**") to pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program if a licensee or working interest participant ("**WIP**") becomes insolvent or is unable to meet its obligations. The Orphan Fund is funded by licensees in the AB LLR Program through a levy administered by the AER. The AB LLR Program is designed to minimize the risk to the Orphan Fund posed by unfunded liability of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines. The AB LLR Program requires a licensee whose deemed liabilities exceed its deemed assets to provide the AER with a security deposit. The ratio of deemed assets to deemed liabilities is assessed once each month and where a security deposit is deemed to be required, the failure to post any required amounts may result in the initiation of enforcement action by the AER. The AER publishes the liability management rating for each licensee on a monthly basis on its public website.

In *Redwater Energy Corporation (Re)* ("**Redwater**"), the Court of Queen's Bench of Alberta found that there was an operational conflict between the abandonment and reclamation provisions of the OGCA, including the AB LLR Program, and the *Bankruptcy and Insolvency Act* (the "**BIA**"). This ruling meant that receivers and trustees have the right to renounce assets within insolvency proceedings, which was affirmed by a majority of the Alberta Court of Appeal. Such a conflict renders the AER's legislated authority unenforceable 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 insolvent. Effectively, this means that abandonment costs will be borne by the industry-funded Orphan Well Fund or the province in these instances because any financial resources of the insolvent licensee will first be used to satisfy secured creditors under the BIA. This decision is currently under appeal to the Supreme Court of Canada, with final resolution expected in 2018.

In response to Redwater, the AER issued several bulletins and interim rule changes to govern while the case is appealed and to allow the Government of Alberta to develop appropriate regulatory measures to adequately address environmental liabilities. The AER's *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals*, which deals with licence eligibility to operate wells and facilities, was amended and now requires extensive corporate governance and shareholder information, with a particular focus on any previous companies of directors and officers that have 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 are assessed on a non-routine basis and the AER now requires all transferees to demonstrate that they have a liability management rating ("**LMR**"), being the ratio of a licensee's assets to liabilities, of 2.0 or higher immediately following the transfer, or to otherwise prove that it can satisfy its abandonment and reclamation obligations. The AER may make further rule changes in response to Redwater at any time, especially as the case heads towards a final determination, which means that additional obligations and/or different requirements may be forthcoming.

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 by 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. The IWCP completed its second year on March 31, 2017. Overall, the AER has announced that licensees brought 19% of non-compliant wells in the IWCP into compliance with AER requirements in the second year of the IWCP.

Climate Change Regulation

Climate change regulation at both the federal and provincial level has the potential to significantly affect the regulatory environment of the crude oil and natural gas industry in Canada.

In general, there is some uncertainty with regard to the impacts of federal or provincial climate change and environmental laws and regulations, as 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 funds from operations.

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 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 February 1, 2018, 174 of the 197 parties to the convention have ratified the Paris Agreement.

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, increasing annually until it reaches $50/tonne in 2022. A draft legislative proposal for the federal carbon pricing system was released on January 15, 2018. This system would apply 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 in 2018. Four provinces currently have carbon pricing systems in place that would meet federal requirements (Alberta, British Columbia, Ontario and Quebec). The federal government will accept comments on the draft legislative proposals to implement the federal carbon pricing system until February 12, 2018.

On May 27, 2017, the federal government published draft regulations to reduce emissions of methane from the crude oil and natural gas sector. The proposed 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, by introducing new control measures. Among other things, the proposed regulations limit how much methane upstream oil and 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 GHG emissions by about 20 megatonnes by 2030.

Alberta

On November 22, 2015, the Government of Alberta introduced its Climate Leadership Plan (the "**CLP**"). The CLP has four areas of focus: implementing a carbon price on GHG emissions, phasing out coal-generated electricity and developing renewable energy, legislating an oil sands emission limit, and introducing a new methane emissions reduction plan. The Government of Alberta has since introduced new legislation to give effect to these initiatives. The *Climate Leadership Act* came into force on January 1, 2017 and enabled a carbon levy that increased from $20 to $30 per tonne on January 1, 2018. The levy is anticipated to increase again in 2021 in line with the federal legislation. On December 14, 2016, the *Oil Sands Emissions Limit Act* came into force, establishing a 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.

The *Carbon Competitiveness Incentives Regulation* (the "**CCIR**"), which replaces the *Specified Gas Emitters Regulation*, came into effect on January 1, 2018. Unlike the previous regulation, which set emission reduction requirements, the CCIR imposes an output-based benchmark on competitors in the same emitting industry. The aim is to reduce emissions by 20 million tonnes by 2020 and 50 million tonnes by 2030, and targets facilities that emit more than 100,000 tonnes of GHGs per year and mandates quarterly and final reporting requirements. The CCIR compliance obligations will be reduced by 50% and 25% for the 2018 and 2019, respectively, with no reduction for 2020 onward. In addition to the industry-specific benchmarks, each benchmark will decrease annually at a rate of 1%, beginning in 2020. The Government of Alberta intends for this strategy to align with the federal Framework.

The Government of Alberta also signaled its intention through its CLP to implement regulations that would lower methane emissions by 45% by 2025. Regulations are planned to take effect in 2020 to ensure the 2025 target is met.

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 over 15 years to fund two large-scale carbon capture and storage projects that will begin commercializing the technology on the scale needed to be successful. 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

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. Our ability to market our oil and natural gas may depend upon our ability to acquire capacity on pipelines that deliver natural gas to commercial markets or contract for the delivery of crude oil by rail. Deliverability uncertainties related to the distance our reserves are from pipelines, railway lines, processing and storage facilities; operational problems affecting pipelines, railway lines and facilities; and government regulation relating to prices, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business may also affect us.

Prices for oil and natural gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors beyond our control. These factors include economic and political conditions in the United States, Canada, Europe, China and emerging markets, the actions of the Organization of the Petroleum Exporting Countries ("**OPEC**") and other oil and gas exporting nations, governmental regulation, political stability in the Middle East, Northern Africa and elsewhere, the foreign supply and demand of oil and natural gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. A material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of our reserves. We might also elect not to produce from certain wells at lower prices.

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

Oil and natural gas prices are expected to remain volatile for the near future because of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, increased growth of shale oil production in the United States, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and ongoing credit and liquidity concerns. 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 in the Oil and Gas Industry

Recent market events and conditions, including global excess oil and natural gas supply, recent actions taken by OPEC, slowing growth in emerging economies, market volatility and disruptions in Asia, sovereign debt levels and political upheavals in various countries have caused significant weakness and volatility in commodity prices. These events and conditions have caused a significant decrease in the valuation of oil and gas companies and a decrease in confidence in the oil and gas industry. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation. In addition, the inability to get the necessary approvals to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the oil and gas industry in Western Canada has led to additional downward price pressure on oil and gas produced in Western Canada and uncertainty and reduced confidence in the oil and gas industry in Western Canada. Lower commodity prices may also affect the volume and value of our reserves, rendering certain reserves uneconomic. In addition, lower commodity prices restrict our funds from operations resulting in less funds from operations 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. Any decrease in value of our reserves may reduce the borrowing base under our Credit Facility, which, depending on the level of our indebtedness, could result in us having to repay a portion of our indebtedness. 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 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 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. If these conditions persist, our funds from operations may not be sufficient to continue to fund our operations and to satisfy our obligations when due and our ability to discharge our obligations will require additional equity or debt financing and/or proceeds or reduction in liabilities from asset sales. There can be no assurance that such equity or debt financing will be available on terms that are satisfactory to us or at all. Similarly, there can be no assurance that we will be able to realize any or sufficient proceeds or reduction in liabilities from asset sales to discharge our obligations.

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. During the 2016 presidential campaign a number of election promises were made and the new American administration has begun taking steps to implement certain of these promises. Included in the actions that the administration has discussed are the renegotiation of the terms of the North American Free Trade Agreement, withdrawal of the United States from the Trans-Pacific Partnership, imposition of a tax on the importation of goods into the United States, reduction of regulation and taxation in the United States, and introduction of laws to reduce immigration and restrict access into the United States for citizens of certain countries. It is presently unclear exactly what actions the new administration in the United States will implement, and if implemented, how these actions may impact Canada and in particular the oil and gas industry. Any actions taken by the new United States 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 gas companies, including us.

In addition to the political disruption in the United States, the citizens of the United Kingdom recently voted to withdraw from the European Union and the Government of the United Kingdom has begun taken steps to implement such withdrawal. 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. 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.

In addition, due to the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations we may be required to satisfy such obligations and to seek 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, we potentially becoming subject to additional liabilities relating to such assets and may have 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.

Risks Associated with Forecast Prices

Our reserves as at December 31, 2017 are estimated using forecast pricing escalating prices as set forth under "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data – Pricing Assumptions*". These prices are substantially above current oil and natural gas prices. If oil and gas prices stay at current levels our reserves may be substantially reduced as economic limits of developed reserves are reached earlier and undeveloped reserves become uneconomic at such prices. Even if some reserves remain economic at lower price levels, sustained low prices may compel us to re-evaluate our development plans and reduce or eliminate various projects with marginal economics.

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 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 as well as 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 and effective maintenance operations 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 funds from operations 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, the environment and personal injury. Particularly, we may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural 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 all the risks typically associated with such operations, 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 in an amount that we consider consistent with industry practice, liabilities associated with certain risks could exceed policy limits or not be covered. In either event, we could incur significant costs.

Gathering and Processing Facilities, Pipeline Systems and Rail

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by rail. The amount of oil and natural gas that we can produce and sell is subject to the accessibility, availability, proximity and capacity of these gathering and processing facilities, pipeline systems and railway lines. The lack of 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 limit the ability to transport produced oil and gas to market. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas. 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 are increasingly turning to rail as an alternative means of transportation. In recent years, the volume of crude oil shipped by rail in North America has increased dramatically. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays or uncertainty in constructing new infrastructure systems and facilities could harm our business and, in turn, our financial condition, operations and funds from operations. Announcements and actions taken by the governments of British Columbia and Alberta relating to approval of infrastructure projects may continue to intensify, leading to increased challenges to interprovincial and international infrastructure projects moving forward. In addition, while the federal government has recently introduced draft legislation to overhaul the existing environmental assessment process and replace the NEB with a new regulatory agency, the impact of the new proposed regulatory scheme on proponents and the timing of receipt of approvals of major projects remains unclear.

Following major accidents in Lac-Megantic, Quebec and North Dakota, the Transportation Safety Board of Canada and the U.S. National Transportation Board have recommended additional regulations for railway tank cars carrying crude oil. In June 2015, as a result of these recommendations, the Government of Canada passed the *Safe and Accountable Rail Act* which increased insurance obligations on the shipment of crude oil by rail and imposed a per tonne levy of $1.65 on crude oil shipped by rail to compensate victims and for environmental cleanup in the event of a railway accident. In addition to this legislation, new regulations have implemented the TC-117 standard for all rail tank cars carrying flammable liquids which formalized the commitment to retrofit, and eventually phase out DOT-111 tank cars carrying crude oil. The increased regulation of rail transportation may reduce the ability of railway lines to alleviate pipeline capacity issues and adds additional costs to the transportation of crude oil by rail. On July 13, 2016, the Minister of Transport (Canada) issued Protective Direction No. 38, which directed that the shipping of crude oil on DOT-111 tank cars end by November 1, 2016. Tank cars entering Canada from the United States will be monitored to ensure they are compliant with Protective Direction No. 38.

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 materially adverse effect on our ability to process our production and deliver the same for sale. 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 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 gas market. In certain jurisdictions institutions, including government sponsored entities, have determined to decrease their ownership in oil and 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 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 assets 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 the state of the market 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 the current low and volatile commodity prices, many companies, including companies that may operate some of the assets in which we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations we may be required to satisfy such obligations and to seek 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, NuVista potentially becoming subject to additional liabilities relating to such assets and NuVista 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.

Project Risks

We manage a variety of small and large projects in the conduct of our business. Project delays may delay expected revenues from operations. Significant project cost 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:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the 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;
- the effects of inclement weather;
- the 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 and may be unable to market the oil and natural gas that we produce effectively.

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, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and 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.

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 NuVista is ultimately able to produce from its reserves.

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 current conditions in the oil and gas industry have negatively impacted the ability of oil and gas companies to access additional financing. 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 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 gas industry have negatively impacted the ability of oil and gas companies to access additional financing. Due to the conditions in the oil and 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 gas industry have negatively impacted the ability of oil and gas companies to access additional financing.

Reserves Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future net revenue attributed to such reserves. The reserve and associated future net revenue information set forth in this document are estimates only. Generally, estimates of economically recoverable oil and natural gas reserves and the future net revenues from such estimated reserves are based upon a number of variable factors and assumptions, such as:

- historical production from the 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. 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. 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. We apply technical and process controls in line with industry-accepted standards to protect our information assets and systems; 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. 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.

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 enjoy technological advantages and may in the future allow them to implement new technologies before us. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. 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 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 devices 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. In addition, advancements in energy efficient products have a similar effect on the demand for oil and 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 funds from operations by decreasing our profitability, increasing its costs, limiting its access to capital and decreasing the value of its assets.

Reputational Risk Associated with our Operations

Any environmental damage, loss of life, injury or damage to property caused by our operations could damage our reputation in the areas in which we operate. Negative sentiment towards us could result in a lack of willingness of municipal authorities being willing to grant the necessary licenses or permits for us to operate our business and in residents in the areas where we are doing business opposing further operations in the area by us. 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 consultant to operate its business. Further, our reputation could be affected by actions and activities of other corporations operating in the oil and gas industry, over which we have no control. In addition, environmental damage, loss of life, injury or damage to property caused by our operations 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 concerns of the effects of the use of fossil fuels on climate change, concerns of the impact of oil and gas operations on the environment, concerns of environmental damage relating to spills of petroleum products during transportation and concerns of indigenous rights, have affected certain investors' sentiments towards investing in the oil and gas industry. As a result of these concerns, some institutional, retail and public investors have announced that they no longer are willing to fund or invest in oil and gas properties or companies or are reducing the amount thereof over time. In addition, certain institutional investors are requesting that issuers develop and implement more robust social, environmental and governance policies and practices. Developing and implementing such policies and practices can involve significant costs and require a significant time commitment from our Board, management and employees Failing to implement the policies and practices as requested by institutional investors may result in such investors reducing their investment in us or not investing in us at all. Any reduction in the investor base interested or willing to invest in the oil and gas industry and more specifically, us, may result in limiting our access to capital, increasing the cost of capital, and decreasing the price and liquidity of our Common Shares.

Regulatory

Various levels of governments impose extensive controls and regulations on oil and natural gas operations (including exploration, development, production, pricing, marketing and transportation). Governments may regulate or intervene with respect to exploration and production activities, prices, taxes, royalties and the exportation of oil and natural gas. 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. Recently, the federal government and certain provincial governments have taken steps to initiate protocols and regulations to limit the release of methane from oil and gas operations. Such draft regulations and protocols may require additional expenditures or otherwise negatively impact our operations, which may affect our profitability. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulations*".

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.

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. On January 29, 2016, the Government of Alberta adopted a new royalty regime which took effect on January 1, 2017. 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. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*". In Canada, the federal and certain provincial governments have implemented legislation aimed at incentivizing the use of alternatives fuels and in turn reducing carbon emissions. The 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 its 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. These programs involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is generally required. Changes to the required ratio of our deemed assets to deemed liabilities or other changes to the requirements of liability management programs may result in significant increases to our compliance obligations. In addition, the liability management regime may prevent or interfere with our ability to acquire or dispose of assets, as both the vendor and the purchaser of oil and gas assets must be in compliance with the liability management programs (both before and after the transfer of the assets) for the applicable regulatory agency to allow for the transfer of such assets. The recent Alberta Court of Queen's Bench decision, *Redwater Energy Corporation (Re)*, found an operational conflict between the *Bankruptcy and Insolvency Act* and the AER's abandonment and reclamation powers when the licensee is insolvent, which was affirmed by a majority of the Alberta Court of Appeal, and has been appealed by the AER to the Supreme Court of Canada for final determination. In response to the decision, the AER issued interim rules to administer the liability management program and until the Government of Alberta can develop new regulatory measures to adequately address environmental liabilities. There remains a great deal of uncertainty as to what new regulatory measures will be developed by the provinces or in concert with the federal government, as the final ruling will become binding in all Canadian jurisdictions. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management Rating Programs*".

Climate Change

Our exploration and production facilities and other operations and activities emit greenhouse gases which may require us to comply with GHG emissions legislation at the provincial or federal level. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place. As a signatory to the UNFCCC and a signatory to the Paris Agreement, which was ratified in Canada on October 3, 2016, the Government of Canada pledged to cut its GHG emissions by 30 per cent from 2005 levels by 2030. One of the pertinent policies announced to date by the Government of Canada to reduce GHG emission is the planned implementation of a nation-wide price on carbon emissions. Provincially, the Government of Alberta has already implemented a carbon levy on almost all sources of GHG emissions, now at a rate of $30 per tonne. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, concerns about climate change have resulted in a number of environmental activists and members of the public opposing the continued exploitation and development of fossil fuels. Given the evolving nature of the debate related to climate change and the control of GHG and resulting requirements, it is expected that current and future climate change regulations will have the affect of increasing our operating expenses and in the long-term reducing the demand for oil and gas production resulting in a decrease in our profitability and a reduction in the value of its assets or asset write-offs. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

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 its exploration and development activities, and if applicable, the cash available for dividends and could negatively impact the market price of the 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 have recently increased they remain volatile as a result of various factors including 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.

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;
- the 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 of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically leased from third parties) as well as skilled personnel trained to use such equipment in the areas where such activities will be conducted. Demand for such limited equipment and skilled personnel, or access restrictions, may affect the availability of such equipment and skilled personnel to us and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that a defect in the chain of title will not arise. Our actual interest in properties may accordingly vary from our records. If a title defect does exist, it is possible that we may lose all or a portion of the properties to which the title defect relates, which may have a material adverse effect on our business, financial condition, results of operations and prospects. There may be valid challenges to title or legislative changes, which affect our title to the oil and natural gas properties we control that could impair our activities on them and result in a reduction of our revenues.

Insurance

Our involvement in the exploration for and development of oil and natural gas properties may result us becoming subject to liability for pollution, blow outs, leaks of sour natural 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 events throughout the world that cause disruptions in the supply of oil continuously affect the marketability and price of oil and natural gas acquired or discovered by us. Conflicts, or conversely peaceful developments, arising outside of Canada, including changes in political regimes or the parties in power, 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.

Eco-Terrorism Risks

Our oil and natural gas properties, wells and facilities could be the subject of a terrorist attack. If any of our properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on our business, financial condition, results of operations and prospects. We do not have insurance to protect against the risk from terrorism.

Dilution

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

Management of Growth

We may be subject to growth related risks including capacity constraints and pressure on its 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. Our inability to deal with this growth 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 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, relating 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 as a result, could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail in any such legal 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.

Aboriginal Claims

Aboriginal 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 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 its 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. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Road bans and other restrictions generally result in a reduction of drilling and exploratory activities and may also result in the shut-in of some of our production if not otherwise tied-in. Certain oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict our ability to access our properties, cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions.

Third Party Credit Risk

NuVista may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production and other parties. In addition, we may be exposed to third party credit risk from operators of properties in which we have a working or royalty interest. In the event such entities fail to meet their contractual obligations to us, such failures may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of 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, we may unable to collect all or portion of any money owing from such parties. Any of these factors could materially adversely affect our financial and operational results.

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 ABCA which require a director of 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*".

Reliance on Key Personnel

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

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

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 have been retained by all parties to assist with the litigation and the action is moving forward. We are currently looking at possible next steps to find resolution and recovery of losses.

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. A statement of defence from us has not yet been requested.

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 the 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 8, 2018. Additional financial information is contained in our financial statements for the year ended December 31, 2017 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, 2017, 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

February 12, 2018

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"):

1. We have evaluated the Company's reserves data as at December 31, 2017. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2017, estimated using forecast prices and costs.

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

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

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

5. 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, 2017, 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	December 31, 2017	Canada	—	1,782,109	—	**1,782,109**

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

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

8. 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, January 31, 2018.

(signed) "*Myron J. Hladyshevsky*"
P. Eng., Vice President

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 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 8, 2018.

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