ANNUAL INFORMATION FORM
DATED MARCH 28, 2022

NUVISTA ENERGY LTD

www.nuvistaenergy.com

WHO WE ARE

NuVista Energy Ltd. is a mid-cap Canadian energy company with top-tier assets in one of the premier economic resource plays in North America, the Montney. Originally founded in 2003, NuVista has grown significantly over the years. Since 2013 specifically, NuVista has grown production from 14,000 Boe/d to current production of over 60,000 Boe/d, with industry leading Environmental, Social and Governance performance. NuVista has a strong track record with a commitment to the highest safety standards, delivering best in class well results with a focus on maximizing value for our shareholders.

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

WHAT'S INSIDE

SELECTED TERMS

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

Entities

Board of Directors or Board means our board of directors.

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

Shareholders means holders of our Common Shares.

Reserves

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

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

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

GLJ Reserve Report means the report of GLJ dated February 10, 2022 evaluating as of December 31, 2021, 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 which were redeemed in July of 2021 with the proceeds from the issuance of the 2026 Notes.

2026 Notes means our 7.875% senior unsecured notes due July 23, 2026.

Common Shares means our common shares.

Other

Credit Facility means our extendible revolving term credit facility available from a syndicate of lenders.

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

Montney means the Montney formation in the Alberta Deep Basin.

CONVENTIONS

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

ABBREVIATIONS

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

Other	
AECO	pricing point for gas transacted on TransCanada Pipeline's Alberta System
API	American Petroleum Institute
°API	an indication of the specific gravity of crude oil measured on the API gravity scale
BOE or Boe	barrel or barrels of oil equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one barrel of oil
Boe/d	barrels of oil equivalent per day
CGR	condensate-gas ratio
CO2e	carbon dioxide equivalent
ESG	environment, social and governance
GHG	greenhouse gas
m^3	cubic metres
Mcfe	thousand cubic feet of gas equivalent, using the conversion factor of six Mcf of natural gas being equivalent to one barrel of oil
MBoe	thousand barrels of oil equivalent
NYMEX	The New York Mercantile Exchange
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for the crude oil standard grade
$000s	thousands of dollars

CONVERSIONS

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

FORWARD-LOOKING INFORMATION AND STATEMENTS

This Annual Information Form, including documents referred to herein, contains forward-looking information and statements (collectively, "**forward-looking statements**"). These forward-looking statements relate to our future events or our future performance. All information and statements other than statements of historical fact contained in this Annual Information Form are forward-looking statements. Such forward-looking statements may be identified by looking for words such as "about", "approximately", "may", "believe", "expects", "will", "intends", "should", "plan", "budget", "predict", "potential", "projects", "anticipates", "forecasts", "estimates", "continues" or similar words or the negative thereof or other comparable terminology. In addition, there are forward-looking statements in this Annual Information Form under the headings: "*Oil and Gas Advisories – Drilling Locations*" as to the reclassification of contingent resources as reserves; "*NuVista Energy Ltd. – Summary Description of our Business*" as to our business focus, plans and strategy; "*General Development of our Business*" as to our business focus, plans and strategy, and our ESG plans; "*General Description of our Business*" as to our business plan and focus, current and future drilling inventory, our future development plans, current and future infrastructure capacity and development plans, capital allocation plans, drilling and completion costs, access to markets, our commodity risk management program, our future exposure to AECO, our long term strategy with respect to acceptable debt levels, our growth potential and plans, our ESG plans, and the impact of the renegotiation or termination of contracts or subcontracts; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data*" as to our reserves and future net revenue from our reserves, income taxes, operating costs, abandonment and reclamation costs, pricing, exchange and inflation rates; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Additional Information Relating to Reserves Data*" as to the development of our proved undeveloped reserves and probable undeveloped reserves, the significant economic factors or significant uncertainties affecting our reserves data and our anticipated abandonment and reclamation costs and liability, drilling and completion plans, future developments costs, our ability to fund future developments costs through cash flow from operating activities and debt and equity issuances and anticipated funding costs; "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information*" relating to our principal oil and natural gas properties, drilling, completion, processing and transportation plans, 2022 capital expenditure, exploration and development activities, the sources of funding for development costs, anticipated land expiries, hedging and marketing policies and plans, our future marketing plans, processing and transportation arrangements and plans, reclamation and abandonment obligations, plans relating to the satisfaction of our volume commitments, and our tax horizon; "*Dividends*" as to our dividend policy and plans to focus upon prudent profitable growth, capital discipline, and rapid reduction of net debt; "*Description of our Capital Structure – Credit Facility*" as to the anticipated renewal of our Credit Facility; and *"Legal Proceedings and Regulatory Actions"* as to our plans and expectations regarding these proceedings.

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

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

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

Statements relating to "reserves" and "resources" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and that the reserves or resources can be profitably produced in the future.

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

- impacts of pandemics;
- environmental and climate change risks;
- the impact of negative public and investor sentiment;
- reputational risks associated with our operations;
- potential opposition from non-governmental organizations;
- fluctuation in the supply and demand for oil and natural gas;
- political or economic developments;
- changes in general economic, market and business conditions;
- uncertainty regarding the impact of legal developments pertaining to Indigenous rights and treaty claims;
- ability to obtain regulatory and other third party approvals;
- uncertainties and changes in royalty regimes and other regulatory changes;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- access to a skilled workforce;
- the impact of the geographical concentration of our assets;
- inflation and cost management;

- management of growth;
- the ability to access sufficient capital from internal and external sources;
- access to capital and fluctuations in the costs of borrowing;
- our credit ratings;
- market prices of oil and natural gas and differentials;
- stock market volatility;
- our ability to market our oil and natural gas;
- exploration, development and production risks;
- operational risks and liabilities inherent in oil and natural gas operations;
- geological, technical, drilling and processing problems;
- the occurrence of unexpected events;
- risks associated with hydraulic fracturing and waterflooding;
- incorrect assessments of the value of acquisitions;
- operational dependence on others and third party risks;
- project risks;
- the accuracy of oil and gas reserves estimates and estimated production levels as they are affected by exploration and development drilling and estimated decline rates;
- the uncertainties in regard to the timing of our exploration and development program;
- information technology and cyber-security issues;
- costs of new technologies;
- variations in foreign exchange or interest rates;
- the impact of our risk management activities;
- our title to and rights to produce from our assets;
- availability and costs of insurance;
- the results of litigation or regulatory proceedings that may be brought against us;
- impacts of the Russian Ukrainian conflict and related actions;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry;
- exposure to third party credit risks;
- our firm commitment transportation and processing arrangements; 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 referred to herein, identifies additional factors that could affect our operating results and performance. We urge you to carefully consider those factors.**

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

OIL AND GAS ADVISORIES

Oil and Gas Metrics

We have adopted the standard of 6 Mcf:1 Bbl when converting natural gas to oil equivalent and 1 Bbl:6 Mcf when converting oil to natural gas equivalent. Boes may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf:1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. **Given that the value ratio based on the current price of crude oil as compared to natural gas may be different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.**

Drilling Locations

We disclose drilling locations in this Annual Information Form in two categories: (i) undeveloped proved plus probable drilling locations; and (ii) undeveloped contingent resources drilling locations. Undeveloped proved locations and probable locations are derived from the GLJ Reserve Report and account for drilling locations that have associated undeveloped proved and/or probable reserves, as applicable. Undeveloped contingent resource drilling locations are derived from a report prepared by GLJ evaluating our contingent resources as of December 31, 2021 ("**GLJ Contingent Resource Repor**t"), and account for undeveloped drilling locations that have associated contingent resources based on a best estimate of such contingent resources.

Of the 1,164 gross (1,077 net) drilling locations identified herein, 340 gross (323 net) are undeveloped proved and probable locations and 824 gross (754 net) are contingent resource locations. There is no certainty that we will drill all drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas production. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. In the case of the contingent resources estimated in the GLJ Contingent Resource Report, contingencies include: (i) further delineation of interest lands; (ii) corporate commitment, and; (iii) final development plan. To further delineate interest lands additional wells must be drilled and tested to demonstrate commercial rates on the resource lands. Reserves are only assigned in close proximity to demonstrated productivity. As continued delineation drilling occurs, a portion of the contingent resources are expected to be reclassified as reserves. Confirmation of corporate intent to proceed with remaining capital expenditures within a reasonable timeframe is a requirement for the assessment of reserves. Finalization of a development plan includes timing, infrastructure spending and the commitment of capital. Determination of productivity levels is generally required before the company can prepare firm development plans and commit required capital for the development of the contingent resources. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources.

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 Pipestone and Wapiti areas of the Alberta Deep Basin. 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.

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

We have one subsidiary, NuVista Clean Canadian LNG Ltd., which has a minority interest in the Rockies LNG Limited Partnership.

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

GENERAL DEVELOPMENT OF OUR BUSINESS

History and Development

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

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

Asset Dispositions

We did not complete any producing property dispositions in the last three years ending December 31, 2021, other than as described below.

During the first quarter of 2021, we completed the divestiture of our non-core Charlie Lake and Cretaceous unit assets in the Wembley area, as well as selected water infrastructure assets in the Wembley/Pipestone area, for total net proceeds of $92.5 million. The sale included production of approximately 1,100 Boe/d and a reduction in our asset retirement obligations of $17.6 million. There was no change to our ownership in our core Montney assets in Pipestone, Wapiti, and the surrounding area and no material change to our ownership in the Wembley gas plant. The proceeds were applied to reduce borrowings on our Credit Facility with no reduction in the credit facility capacity, further improving our liquidity and undrawn credit capacity. In exchange for the divestiture of the selected water infrastructure assets, we have entered into a long term water disposal contract.

Asset Acquisitions

We did not complete any property acquisitions in the last three years ending December 31, 2021 although we did complete a number of minor undeveloped land swaps for the purpose of consolidation of our land footprint.

ESG

On August 23, 2021 we released our 2020 ESG Report. We continue to make significant progress on a number of ESG fronts including the following:

Environment

Approximately 60% of our current production is comprised of natural gas which has the lowest carbon footprint of any hydrocarbon, leading to our GHG performance being well below the North American benchmark. Our efforts to reduce GHG emissions, and to be a front runner in eliminating routine vented methane emissions, continued in 2021. In our Wapiti area we completed a project to capture routine vented methane from pneumatic instruments, and direct them to flare for a 95% reduction in GHG equivalent emissions. This project is another positive step towards NuVista's commitment to reducing methane emissions. Our efforts started in prior years with swapping "high bleed" pneumatic devices for "low bleed" devices at new and existing sites. This is now standard practice, and our attention has turned to complete elimination. In our Pipestone area we have continued with the build out of our centralized instrument air system, to maintain a standard of zero routine vented methane emissions at our well pad sites. At Bilbo, we are installing a vapor recovery unit, with start up scheduled in the first quarter of 2022, to eliminate routine flaring of tank vapors. Details on NuVista's emissions reduction targets can be found in our ESG report which is available on our website. More details on our emissions reduction efforts can be found within our 2020 submission to the Carbon Disclosure Project. Through our focused efforts, we continue to make good strides in the reduction of fresh water use for drilling and completion activities. We successfully completed a produced water recycling pilot at our Elmworth compressor station. We plan to build on this success with an expanded recycling pilot in 2022. Throughout the year we also made material progress in our water usage reduction efforts through continued tweaking in our completion design, a municipal waste water pilot and the integration of a non-potable water source into our operations. These initiatives reduced our annual high quality fresh water requirements by more than 20%.

We also continued our progress on responsibly abandoning and reclaiming inactive wells and facilities. Throughout 2021, we spent $6.7 million on abandonment and reclamation work. Many of these dollars result in local economic and employment benefits to remote parts of Alberta, and we are actively working with our First Nation partners in these areas to ensure they are participating in these benefits as well. NuVista successfully brought additional inactive sites to closure with the receipt of 31 reclamation certificates in 2021.

Social

NuVista is committed to conducting its activities in a manner that protects the health and safety of its workers and the public while minimizing our impact on the environment. We always strive towards a goal of zero injuries for our employees and third-party contractors working on our sites. In 2021, our Lost Time Injury Frequency ("**LTIF**") was zero and Total Recordable Injury Frequency ("**TRIF**") was 0.64 per 200,000 worker hours. TRIF has trended up slightly over the past year, fortunately with relatively low impact incidents, and we are working on measures towards seeing a reduction in 2022.

Of key importance to us at NuVista is maintaining focus on high-potential near-miss incidents which are uncontrolled hazards and near-miss events which did not result in serious harm to people or the environment, but could have if conditions were slightly different. These provide more impactful preventative learnings than low impact incidents. We were encouraged to see fewer of these incidents in 2021 compared to 2020. These cases receive heightened attention at all levels of the organization, and in 2021 we implemented an annual look back to ensure corrective actions put in place over the prior year have stayed in place and are functioning as intended. We also continued to embed Energy Safety Canada's 10 Life Saving Rules through our operations. These rules are a key tool in preventing the most frequent causes of fatalities and serious injury within our industry.

Investment in our people and the communities where we live and operate continues to be a top priority. Throughout 2021, we continued to support our staff through the many challenges COVID-19 presented. We went above and beyond the standards set by the local governments and health authorities to ensure our employee's health and safety and the safety of those we work directly with.

In December of 2021, we launched our annual employee engagement survey. We had a 98% participation rate indicating how much employees trust and value the process. We are proud and grateful to repeatedly receive scores that indicate best in class levels of staff engagement across our business. Some highlights from our 2021 survey include a 97% favorable rating for questions including: NuVista is committed to safety as a top priority, I am proud to work for NuVista, and I would recommend NuVista as a great place to work. We asked staff to comment about what makes them most proud to work at NuVista and here's what they shared with us:

- "I'm valued and respected as an employee. I enjoy what I do, and am surrounded by a fantastic team of understanding and amazing people."

- "I am most proud of our ongoing commitment to safety and the environment.

- "I feel that NuVista genuinely cares about the Company's employees and will do the right thing regardless of cost. NuVista is also taking strides in working with stakeholders in the areas we operate, specifically Indigenous communities."

Despite the challenges facing our industry and the impacts of the pandemic on our people, we continued to donate our time and money in support of the many charitable organizations that make a difference in our communities. Giving is at the heart of our organization and in 2021 we set a target to double our NuVista community investment contributions by 2025 to $600,000 from our 2020 baseline. NuVista has always supported the United Way and in 2021, we dug deep and had our best campaign ever, raising a total of $160,000 for the United Way. This couldn't have been done without the generosity of our staff, supported by NuVista's dollar for dollar matching program.

Throughout 2021 NuVista continued to emphasize building relationships with the Indigenous communities with whom we work and consult. NuVista's approach is informed by the four pillars of our Indigenous Inclusion Guiding Principles: cultural understanding, meaningful engagement, economic participation, and community involvement.

In 2021, NuVista conducted several cultural awareness training sessions and events, with all employees having participated in at least one event. Our engagement efforts included the second year of our Northwest Alberta abandonment and decommissioning program. This program involved partnering with a First Nation to design our program and select contractors. The First Nation then served as prime contractor. The program included numerous Indigenous suppliers in many key capacities ranging from civil work to safety to environmental.

In 2021, our efforts in Indigenous economic participation included the continued broadening of our utilization of Indigenous-owned suppliers, with NuVista spending over $4.8 million on Indigenous-owned businesses and an additional $5.7 million on businesses that were affiliated or partnered with First Nations with whom we consult. NuVista also provided funding for the education and training of Indigenous workers.

With respect to community involvement, our efforts in 2021 included providing over $100,000 in community investment funds. These were used for many purposes, including funding Indigenous leadership and cultural programs, facilities refurbishment, and a children's breakfast program. In addition, NuVista provided direct financial assistance and assistance in kind to help a First Nation with their response to a local disaster.

Governance

We believe we have world class governance standards, like so many of our Canadian peers. Governance plays a key role in providing leadership to our organization. Our Governance & Compensation and ESG Committees provide Board oversight of our policies and programs and ensures Management's continued focus on these key principles. These principles provide a framework for our field and head office staff to operate in a safe and environmentally conscious manner. We continue to strive to improve these initiatives and are committed to achieving our plans in the future.

To ensure continuous improvement, here are a few of the governance items upon which we are focused: We have met our diversity target of 20% for female Board membership by year end 2021 with the addition of K.L. (Kate) Holzhauser in November. We have also set a new target to achieve 30% female Board membership by our annual shareholders meeting in 2023 to ensure continuous progress in diversity. Our executive and staff compensation targets have been previously changed to include ESG in addition to traditional financial and reserve metrics. NuVista has also updated our internal Enterprise Risk Management process to ensure appropriate Board oversight and continued focus on risk assessment, prevention and mitigation.

Senior Unsecured Notes

On July 23, 2021, we issued $230.0 million aggregate principal amount of 7.875% senior unsecured notes due July 23, 2026. Part of the proceeds from the 2026 Notes were used to redeem the full aggregate principal amount of $220 million of the 2023 Notes at a redemption price of 101.625%, plus accrued and unpaid interest.

Credit Facility

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

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

On April 27, 2020, we completed the annual review of our borrowing base and our lenders decreased the Credit Facility from $550 million to $475 million.

On September 29, 2020, we closed a $40 million unsecured letter of credit facility under Export Development Canada's Account Performance Security Guarantee program and subsequently transferred the majority of the existing letters of credit under the Credit Facility to this unsecured letter of credit facility.

On November 10, 2020, we completed the semi-annual redetermination of our borrowing base and, among other things, our lenders decreased the Credit Facility from $475 million to $440 million and the annual and semi-annual renewal date of the Credit Facility was changed from April 30 to May 31, and from October 31 to November 30, respectively.

Senior Management

In May 2019, Mr. Chris LeGrow, formerly Manager, Planning & Corporate Development was appointed to Vice President, Development and Planning. Ms. Tanya Dickison, formerly Manager, HR, was added to the Leadership Team on May 7, 2021. Ms. Dickison was subsequently promoted to the position of Director, Human Resources and ESG Communications in March of 2022.

GENERAL DESCRIPTION OF OUR BUSINESS

Business Plan and Growth Strategies

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

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

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

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 and ultimately return cash to Shareholders.

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 near the City of Grande Prairie, Alberta. We hold rights in approximately 156,640 gross acres (140,880 net acres) of land with an approximate working interest of 90%. Currently, over 99% of our production is located within the Wapiti and Pipestone areas. We have an inventory of approximately 1,164 gross drilling locations (340 undeveloped proved and probable drilling locations and 824 undeveloped best estimate contingent drilling locations), which includes Montney intervals with current production or with direct offset production. Based on our current drilling pace, this provides for approximately 30 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 Montney assets have a CGR that ranges from approximately 20 Bbl/MMcf to over 200 Bbl/MMcf with most wells in the 50 to 150 range. This high CGR enables our production mix to average approximately 28% to 32% condensate in Boe terms. As a result, our condensate revenue over the last three years comprised approximately 60% of our total petroleum and gas revenues. Condensate volumes are used primarily as a diluent for oil sands production and as a result, have historically traded at par or a slight premium to WTI prices.

Operational Excellence

We have a long history of operational excellence and continuous improvement. Well costs and well performance have improved in parallel resulting in a material improvement in capital efficiency and economics. As the bulk of the required infrastructure to accommodate our growth strategy is in place, the majority of our capital expenditures moving forward will be allocated to drilling, completing and equipping new wells. We have achieved significant continuous improvement in drilling and completion costs per unit, while increasing well performance and results. In addition, late in the first quarter of 2021, an operated compressor station was brought on-stream at Pipestone North, below budget and marks a major milestone as the last large infrastructure project to underpin our growth to 90,000+ Boe/d. As a result of the completion of our facility build out, approximately 85% of future capital expenditures to reach our targeted production level of between 85,000 to 90,000 Boe/d (estimated product breakdown of 62% natural gas, 30% condensate and 8% NGLs) are related to drilling, completion, equip and tie-in activities.

Strong Market Access and Egress

We have firm transportation egress and processing agreements as well as both owned and third party owned infrastructure in place to support our growth plan. Our Bilbo and Elmworth blocks, which have productive capacities of 18,000 Boe/d and 19,000 Boe/d, respectively are supported by owned and operated compressor stations. Our Gold Creek block, which has productive capacity of 10,000 Boe/d, is supported by a third party owned and operated facility.

Our Pipestone South block which has a productive capacity of 12,000 Boe/d is supported by a third party owned compressor station which we contract operate. Our Pipestone North block, which has a productive capacity of 35,000 Boe/d, is supported by both owned and third party owned compressor stations which we operate.

The vast majority of our production is processed through five large sour gas plants, Keyera Simonette, Energy Transfer K3, Energy Transfer Wapiti, Veresen Midsteam LP Hythe, and NuVista Wembley. The NuVista capacity at the Hythe plant commenced in the first quarter of 2021 in order to accommodate new production growth from the Pipestone North block.

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

In addition to securing processing agreements, we have contracted for firm pipeline transportation capacity to ensure our natural gas, condensate and natural gas liquids reach market. We have also contracted for long term and/or renewable export pipeline capacity on: the Alliance Pipeline to Chicago, Illinois, the Foothills/GTN system to Malin, Oregon, and the TCPL Mainline system to Dawn, Ontario. This approach has allowed us to reach various North American markets for our natural gas allowing for diversified natural gas 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 cash flow from operating activities against the unpredictable commodity price environment. Our Board 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 as follows:

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

Our existing contracts for firm transportation on export pipelines coupled with the financial NYMEX basis natural gas sales price derivative contracts will result in long term price diversification and exposure to AECO floating pricing limited to approximately 10% to 25% of volumes in 2021 and beyond.

Solid Balance Sheet and Liquidity Position

Our long term strategy has been recently modified to maintain a significantly reduced net debt to adjusted funds flow ratio of less than 1.0x in a stressed commodity price environment of US$ 45/Bbl WTI and US$ 2.00/MMBtu NYMEX natural gas, from a prior target of less than 1.5x. This reduction from our historic 1.5x target reflects our commitment to reducing leverage and enhancing our balance sheet strength and flexibility, and will result in net debt to adjusted funds flow figures far below 1.0x during normalized or high commodity price environments.

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

Experienced Management Team

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

Cyclical and Seasonal Impact of Industry

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

ESG 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 ESG performance. To fulfill the environmental portion of this commitment, our operating practices and procedures are consistent with the extensive requirements and regulations established for the Canadian and Alberta oil and gas industry. 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). We also support and endorse any environmental operating procedures developed by the Canadian Association of Petroleum Producers.

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 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 program; an inspection program for both active and inactive sites; 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 continuously seek, evaluate, and execute methane and greenhouse gas emission reduction opportunities to ensure a pipeline of projects towards continuous reduction in our GHG emission intensity.

We expect to incur abandonment and reclamation costs as existing oil and gas properties are abandoned. In 2021, expenditures for abandonment and reclamation costs, including costs to reclaim and abandon ownership interests in oil and natural gas assets including well sites, and gathering systems and processing facilities totaled $6.7 million. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Significant Factors or Uncertainties – Additional Information Concerning Abandonment and Reclamation Costs*".

We participate in both the Canadian federal and provincial regulated greenhouse gas emissions reporting programs and continue to quantify annual greenhouse gas emissions for internal reporting purposes. In recent years we have made great strides in reducing our production CO_2 intensity to minimize our impact on global climate change and to minimize exposure to potential future carbon taxation. For the 2021 operating year, we have enrolled our operated assets as an aggregate facility into the Government of Alberta's Technology Innovation and Emissions Reduction Regulation.

See also "*General Development of our Business – History and Development – ESG".*

Renegotiation or Termination of Contracts

As at the date hereof, we do not anticipate that any aspect of our business will be materially impaired in the remainder of 2022 by the renegotiation or termination of contracts or subcontracts**.**

Competitive Conditions

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

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, 2021, we employed 89 full-time employees, including 68 office and 21 field employees.

STATEMENT OF RESERVES DATA AND OTHER OIL AND NATURAL GAS INFORMATION

The statement of reserves data and other oil and natural gas information set forth below is dated February 28, 2022. The statement is effective as of December 31, 2021 and the preparation date of the statement is February 10, 2022. 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, 2021, 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, 2021 and the associated management's discussion and analysis should be consulted for additional information regarding our taxes.

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

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND NATURAL GAS RESERVES AND NET PRESENT VALUE OF FUTURE NET REVENUE AS OF DECEMBER 31, 2021 FORECAST PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM CRUDE OIL		CONVENTIONAL NATURAL GAS		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	-	8	1,828	2,076	44,136	34,970	462,991	434,134
Developed Non-Producing	-	-	-	-	4,459	3,580	43,883	40,193
Undeveloped	-	-	-	-	66,446	54,592	750,605	700,511
TOTAL PROVED	-	8	1,828	2,076	115,041	93,142	1,257,480	1,174,838
TOTAL PROBABLE	-	1	437	509	78,683	61,278	983,163	907,341
TOTAL PROVED PLUS PROBABLE	-	9	2,265	2,585	193,723	154,420	2,240,642	2,082,179

	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	2,254,686	1,801,273	1,492,256	1,286,702	1,143,080	13.86	2.31
Developed Non-Producing	260,110	201,077	166,303	143,790	128,043	16.18	2.70
Undeveloped	3,236,061	2,096,926	1,481,707	1,112,397	871,240	8.65	1.44
TOTAL PROVED	5,750,857	4,099,276	3,140,266	2,542,889	2,142,363	10.85	1.81
TOTAL PROBABLE	4,553,171	2,150,210	1,216,339	783,022	551,939	5.72	0.95
TOTAL PROVED PLUS PROBABLE	10,304,028	6,249,487	4,356,606	3,325,911	2,694,302	8.68	1.45

Note:

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

	NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
PROVED:					
Developed Producing	2,038,174	1,691,187	1,428,109	1,246,578	1,116,756
Developed Non-Producing	199,906	159,273	135,694	120,576	109,989
Undeveloped	2,484,037	1,596,140	1,113,356	824,102	636,257
TOTAL PROVED	4,722,117	3,446,600	2,677,159	2,191,256	1,863,003
TOTAL PROBABLE	3,505,843	1,643,891	919,083	585,496	409,661
TOTAL PROVED PLUS PROBABLE	8,227,960	5,090,491	3,596,243	2,776,752	2,272,664

RESERVES CATEGORY	REVENUE ($000s) [1]	ROYALTIES ($000s) [2]	OPERATING COSTS ($000s)	DEVELOP-MENT COSTS ($000s)	ABANDON-MENT AND RECLAMATION COSTS ($000s) [3]	FUTURE NET REVENUE BEFORE INCOME TAXES ($000s)	INCOME TAXES ($000s)	FUTURE NET REVENUE AFTER INCOME TAXES ($000s)
TOTAL PROVED	13,561,984	1,576,845	4,711,360	1,282,495	240,427	5,750,857	1,028,741	4,722,117
TOTAL PROVED PLUS PROBABLE	24,922,893	3,108,619	8,995,785	2,211,627	302,834	10,304,028	2,076,068	8,227,960

TOTAL FUTURE NET REVENUE (UNDISCOUNTED) AS OF DECEMBER 31, 2021 FORECAST PRICES AND COSTS

Notes:
(1) Total revenue includes company revenue before royalty and includes other income.
(2) Royalties include Crown, freehold and overriding royalties and mineral tax.
(3) The GLJ abandonment and reclamation costs estimates are based on the Alberta Energy Regulator's Directive 011 - Licensee Liability Rating (LLR) Program: Updated Industry Parameters and Liability Costs. These are estimated abandonment and reclamation of all of our existing and future wells, facilities and pipelines. These include all active and inactive entities within active and inactive assets.

FUTURE NET REVENUE BY PRODUCT TYPE AS OF DECEMBER 31, 2021 FORECAST PRICES AND COSTS

PRODUCT TYPE [1]	NET PRESENT VALUE OF FUTURE NET REVENUE [3][4] (BEFORE DEDUCTING FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT 10%/YEAR) ($000s)	UNIT VALUE [2] [5] (BEFORE DEDUCTING FUTURE INCOME TAX EXPENSES AND DISCOUNTED AT 10%/YEAR) ($/Boe)	($/Mcfe)
PROVED:			
Light and Medium Crude Oil [1]	707	24.72	4.12
Heavy Oil [1]	54	54.31	9.05
Conventional Natural Gas [2]	3,383	7.05	1.17
Shale Gas [2]	3,136,122	10.86	1.81
TOTAL PROVED	3,140,266	10.85	1.81
PROVED PLUS PROBABLE			
Light and Medium Crude Oil [1]	798	23.67	3.95
Heavy Oil [1]	68	52.18	8.70
Conventional Natural Gas [2]	3,923	6.53	1.09
Shale Gas [2]	4,351,817	8.68	1.45
TOTAL PROVED PLUS PROBABLE	4,356,606	8.68	1.45

Notes:
(1) Including solution gas and other by-products.
(2) Including by-products but excluding solution gas.
(3) Other company revenue and costs not related to a specific production group have been allocated proportionately to production groups.

(4) Columns may not add due to rounding.
(5) Unit values are based on net reserve volumes.

Definitions and Notes to Reserves Data Tables

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

1. "**gross**" means:

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

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

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

2. "**net**" means:

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

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

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

3. Definitions used for reserve categories are as follows:

   Reserve Categories

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

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

   (b) the use of established technology; and

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

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

   (a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

   (b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

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

Development and Production Status

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

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing:

(i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty; and

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

Levels of Certainty for Reported Reserves

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

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

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

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

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

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

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

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

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

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

(d) provide improved recovery systems.

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

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

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

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

(c) dry hole contributions and bottom hole contributions;

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

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

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

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

These are prices and costs that are:

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

(b) if and only to the extent that, there are fixed or presently determinable future prices or costs to which we are legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

12. Numbers may not add due to rounding.

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

14. We do not have any synthetic oil.

Pricing Assumptions

The forecast cost and price assumptions in this Annual Information Form assume increases in wellhead selling prices and take into account inflation with respect to future operating and capital costs.

The forecast of prices, inflation and exchange rates provided in the table below were computed using the average of the forecasts ("**IQRE Average Forecast**") by GLJ, McDaniel & Associates Consultants Ltd., and Sproule Associates Limited. The IQRE Average Forecast is dated January 1, 2022. The inflation forecast was applied uniformly to prices beyond the forecast interval, and to all future costs.

Crude oil, natural gas and NGL benchmark reference pricing, inflation and exchange rates utilized in the GLJ Reserve Report were as follows:

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

YEAR	OIL				NATURAL GAS		NATURAL GAS LIQUIDS					
	WTI Cushing Oklahoma ($US/Bbl)	Edmonton Par Price 40° API ($Cdn/Bbl)	Hardisty Heavy 12° API ($Cdn/Bbl)	Cromer Medium 29° API ($Cdn/Bbl)	AECO Natural Gas Price ($Cdn/ MMbtu)	NYMEX Gas ($US/ MMbtu)	Edmonton Ethane ($Cdn/Bbl)	Edmonton Propane ($Cdn/Bbl)	Edmonton Butane ($Cdn/Bbl)	Edmonton C5+ Stream Quality ($/Bbl)	Inflation Rates (3) %/Year	Exchange Rate (4) ($US/ $Cdn)
Forecast												
2022	72.83	86.82	66.46	83.94	3.56	3.85	11.48	43.39	57.49	91.85	0.0	0.797
2023	68.78	80.73	61.90	78.06	3.20	3.44	10.33	35.92	50.17	85.53	2.3	0.797
2024	66.76	78.01	59.44	75.43	3.05	3.17	9.81	34.62	48.53	82.98	2.0	0.797
2025	68.09	79.57	60.64	76.94	3.10	3.24	10.01	35.31	49.50	84.63	2.0	0.797
2026	69.45	81.16	61.87	78.48	3.17	3.30	10.22	36.02	50.49	86.33	2.0	0.797
2027	70.84	82.78	63.10	80.05	3.23	3.37	10.42	36.74	51.50	88.05	2.0	0.797
2028	72.26	84.44	64.38	81.65	3.30	3.44	10.64	37.47	52.53	89.82	2.0	0.797
2029	73.70	86.13	65.67	83.29	3.36	3.51	10.86	38.22	53.58	91.61	2.0	0.797
2030	75.18	87.85	66.68	84.95	3.43	3.57	11.08	38.99	54.65	93.44	2.0	0.797
2031	76.68	89.60	68.02	86.65	3.50	3.65	11.31	39.77	55.74	95.32	2.0	0.797
2032+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.797

Notes:

(1) IQRE Average Forecast effective January 1, 2022.

(2) GLJ assigns a value to our existing physical diversification contracts for natural gas for consuming markets at Dawn, Chicago and Ventura based upon the IQRE Average Forecast, contracted volumes, and transportation costs. No incremental value is assigned to potential future contracts which were not in place as of December 31, 2021.

(3) Inflation rate for costs.

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

Weighted average historical prices realized by us for the year ended December 31, 2021, excluding financial derivative commodity contracts were $4.66/Mcf for natural gas, $84.35/Bbl for condensate and oil, and $35.38/Bbl for NGLs (excluding condensate).

Reserves Reconciliation

Over 2021 our reserves increased primarily as a result of our continued delineation and development of the Montney play, partially offset by the divestiture of our non-core Charlie Lake and Cretaceous unit assets in the Wembley area.

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, 2020	5,228	6,111	11,339	28,631	23,385	52,016
Discoveries	-	-	-	-	-	-
Extensions	-	-	-	-	-	-
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	-	-	-	696	155	851
Acquisitions	-	-	-	-	-	-
Dispositions	(5,194)	(6,111)	(11,305)	(26,718)	(23,052)	(49,770)
Economic Factors	-	-	-	125	(51)	75
Production	(34)	-	(34)	(906)	-	(906)
December 31, 2021	-	-	-	1,828	437	2,265

	NATURAL GAS LIQUIDS			SHALE GAS		
	PROVED (Mbbls)	PROBABLE (Mbbls)	PROVED PLUS PROBABLE (Mbbls)	PROVED (MMcf)	PROBABLE (MMcf)	PROVED PLUS PROBABLE (MMcf)
December 31, 2020	115,684	82,134	197,819	1,244,117	987,915	2,232,032
Discoveries	-	-	-	-	-	-
Extensions	9,811	1,975	11,786	93,646	22,753	116,399
Infill Drilling	-	-	-	-	-	-
Improved Recovery	-	-	-	-	-	-
Technical Revisions	(108)	(2,970)	(3,078)	(19,013)	(31,594)	(50,608)
Acquisitions	-	-	-	-	-	-
Dispositions	(2,820)	(2,745)	(5,565)	-	-	-
Economic Factors	382	289	671	4,797	4,090	8,887
Production	(7,909)	-	(7,909)	(66,068)	-	(66,068)
December 31, 2021	115,041	78,683	193,723	1,257,480	983,163	2,240,642

Note:
(1) Includes solution gas and other associated by-products.

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

Proved Undeveloped Reserves

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

	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		SHALE GAS (MMcf)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2019	1,338	2,072	64,497	959,739
2020	2,308	4,535	21,578	803,659
2021	-	-	28,896	750,605

	CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2019	4,567	10,232	5,652	79,644
2020	7,303	16,773	2,949	72,254
2021	-	-	3,061	66,446

Of our total proved plus probable gross reserves, 191,547 MBoe or 34% are proved undeveloped gross reserves. These well locations are allocated reserves because they are within the defined distances to proved reserve accumulations. The Montney play accounts for 191,547 MBoe or 100% of our proved undeveloped reserves. Subject to market conditions, we expect to develop approximately 38,173 MBoe of these reserves in 2022 and 54,411 MBoe in 2023. The remaining proved undeveloped reserves are planned to be developed within an additional three year time period subject to capital availability and allocation and regulatory and gas processing considerations.

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

Probable Undeveloped Reserves

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

	LIGHT AND MEDIUM CRUDE OIL (Mbbls)		SHALE GAS (MMcf)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2019	2,520	2,769	90,938	783,046
2020	2,575	5,847	7,765	814,010
2021	-	-	31,102	792,487

	CONVENTIONAL NATURAL GAS (MMcf)		NATURAL GAS LIQUIDS (Mbbls)	
YEAR	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END	FIRST ATTRIBUTED	CUMULATIVE AT YEAR END
2019	8,700	10,047	7,352	62,599
2020	8,277	19,135	2,602	65,753
2021	-	-	2,934	61,038

Of our total proved plus probable reserves, 193,119 MBoe or 34% are probable undeveloped gross reserves. These well locations are allocated reserves because they are within the defined distances to proved reserve accumulations. The Montney play accounts for 193,119 MBoe or 100% of our probable undeveloped reserves. Subject to market conditions, we expect to develop approximately 2,118 MBoe of these reserves in 2022 and none in 2023. Remaining probable undeveloped reserves are planned to be developed within an additional eight year time period subject to capital availability and allocation and regulatory and gas processing considerations.

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

Significant Factors or Uncertainties

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

Additional Information Concerning Abandonment and Reclamation Costs

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

As at December 31, 2021, we had approximately 248 net wells for which we expect to incur abandonment and reclamation costs and 499 net wells that have been abandoned but not yet reclaimed. As disclosed in our December 31, 2021 year end financial statements, we calculated our estimated overall abandonment and reclamation costs at $118.3 million (undiscounted and uninflated). This cost discounted is $40.6 million (10% discount). Included in this calculation are the abandonment and reclamation costs for our ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities.

The future net revenues disclosed in this Annual Information Form based on the GLJ Reserve Report contain the abandonment and reclamation costs of all of our existing and future wells, facilities and pipelines. The GLJ Reserve Report deducted $152.8 million (undiscounted and uninflated) and $25.2 million (10% discount) for abandonment and reclamation costs, in estimating the future net revenue disclosed in this Annual Information Form. Included in this calculation are the abandonment and reclamation costs for total proved and probable developed reserves and total proved and probable undeveloped reserves, as well as the abandonment and reclamation costs for wells, facilities and pipelines in our active and inactive assets.

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 COSTS	
YEAR	PROVED RESERVES ($000s)	PROVED PLUS PROBABLE RESERVES ($000s)
2022	281,018	299,318
2023	352,608	352,608
2024	210,351	210,351
2025	249,029	249,029
2026	189,488	203,769
Remaining	-	896,552
Total (Undiscounted)	1,282,495	2,211,627

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

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

Other Oil and Natural Gas Information

Principal Oil and Natural Gas Properties

The following is a description of our principal oil and natural gas properties on production or under development as at December 31, 2021. Information in respect of current production is average production, net to our working interest, except where otherwise indicated.

We hold Montney rights in approximately 156,640 gross acres (140,880 net acres) of land with an average working interest of 90% that are prospective for the Triassic Montney zone resource play. This formation is typified by high rate condensate-rich natural gas. As of the end of 2021, NuVista had 260 horizontal wells developed in the Montney formation.

Our core operating areas of Wapiti and Pipestone in the Montney formation is located near the City of Grande Prairie, Alberta, approximately 600 kilometers northwest of Calgary. This operating area continues to play the fundamental role in our future growth with substantially all our projected 2022 capital budget expected to be spent in this region.

Wapiti

Production from the Montney in the Wapiti area is currently processed at one of three large area processing plants: the Energy Transfer K3 plant, the Keyera Simonette plant, and the Energy Transfer Wapiti plant.

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

During 2021, Wapiti production averaged 27,242 Boe/d, which included 8,065 Bbls/d of condensate, 2,232 Bbls/d of NGLs (excluding condensate), and 101.7 MMcf/d of conventional natural gas. Operations during the year included drilling of twelve Montney horizontal wells and bringing 8 wells on stream into existing capacity.

Pipestone

Production in the Pipestone area is processed primarily at three sour gas plants – the Energy Transfer Wapiti gas plant, the Veresen Midstream LP Hythe gas plant, and the NuVista Wembley gas plant, with an additional smaller amount processed at the Tidewater Pipestone gas plant. The NuVista capacity at the Hythe plant commenced in the first quarter of 2021 in order to accommodate new production growth from the Pipestone North block.

Production at Pipestone averaged 24,371 Boe/d in 2021 which included 8,247 Bbls/d of condensate, 3 Bbls/d of light oil, 2,898 Bbls/d of NGLs (excluding condensate), and 79,337 Mcf/d of conventional natural gas.

In the Pipestone South Block, operations during the year included completion of a six well pad that was spud late in 2020. This pad was brought on-stream in the second quarter of 2021 to fill existing capacity at the Pipestone South Compressor Station. An additional 6 well pad was spud in late 2021 and was brought on-stream in the first quarter of 2022.

In the Pipestone North Block, steady production was achieved from 28 legacy Montney horizontal wells. The construction of the Pipestone North Compressor Station, which is owned by Veresen and contract operated by NuVista continued and came on stream in the first quarter of 2021. A twelve well pad which was drilled in the first quarter of 2020, with the completion and onstream deferred, was brought onstream late in the first quarter of 2021. Two additional 6 well pads were drilled, completed and brought on production over the course of the third and fourth quarters. An additional 7 well pad was spud in the fourth quarter of 2021 and brought on production in the first quarter of 2022. Substantially all production from these pads flows to the Veresen Hythe Gas Plant and to a lesser extent to the NuVista Wembley Gas Plant.

Non-core Areas

Production in the non-core area of Wembley, which is in the greater Wapiti-Montney area, was 103 Boe/d in 2021 which included 20 Bbls/d of condensate and light oil, 20 Bbls/d of NGLs (excluding condensate), and 378 Mcf/d of conventional natural gas.

We also have non-core operations in three additional areas of Alberta (non-core properties outside of the greater Wapiti-Montney area) whose combined production in 2021 averaged 103 Boe/d. Substantially all of the 2021 average non-core production is comprised of conventional natural gas. These operating regions combined gross acreage in 2021 is 222,202 gross acres (158,663 net acres). We are not anticipating spending any development capital in 2022 and did not drill any wells in these regions in the last three years.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2021.

	OIL WELLS				NATURAL GAS WELLS			
	PRODUCING		NON-PRODUCING (2)		PRODUCING		NON-PRODUCING (2)	
	GROSS	NET	GROSS	NET	GROSS	NET	GROSS	NET
Alberta (1)	5.0	0.4	128.0	99.6	326.0	265.7	906.0	748.6

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 63 gross (47.9 net) oil wells and 513 gross (421.0 net) natural gas wells that are properly downhole abandoned but are still in various stages of reclamation.

Properties With No Attributed Reserves

As at December 31, 2021, we held 50,160 gross acres (42,574 net acres) of Montney rights to which no reserves are currently attributed. Rights to explore, develop and exploit 19,360 net acres of these land holdings could expire by December 31, 2022 if not continued. We have no material work commitments other than abandonment obligations on these properties and the majority of this acreage is located in our non-core operating areas. When determining gross and net acreage, where we hold two or more leases granting stratigraphic interests which overlap geographically, the acreage is reported for each lease; where we hold two or more stratigraphic interests in a single lease that overlap geographically, the acreage is reported only once.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

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

Forward Contracts

We are exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of derivative instruments are used by us to reduce our exposure to fluctuations in commodity prices and foreign exchange rates. We are exposed to losses in the event of default by the counterparties to these derivative instruments. We manage this risk by diversifying our derivative portfolio amongst a number of financially sound counterparties. For information in relation to our marketing arrangements, see "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Marketing Arrangements*". For details of our material commitments to sell natural gas and crude oil which were outstanding as at December 31, 2021, see Note 20 to our financial statements for the year ended December 31, 2021.

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	2022 – 2026	2027 - 2038	2022 - 2026	2027 – 2038
Natural Gas (MMcf/d)	-	17	-	-
Condensate & NGL/s (Bbls/d)	7,800	3,300	4,700	-
Estimated Annual Cost (millions)	$11	$11	$7	-

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, 2021 see Note 21 to our financial statements for the year ended December 31, 2021. See "*Risk Factors – Firm Commitment Transportation and Processing Arrangements*".

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, 2022 to June 30, 2023 and up to 60% for July 1, 2023 to December 31, 2024 and a further 50% for the following 24 months. In addition, we may enter into natural gas basis differential contracts, subject to a maximum volume of up to 150,000 MMbtu/day and with a term of less than 6 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 $4.63/Mcf for the year ended December 31, 2021.

We have been contracting for export pipeline capacity to diversify our gas sales to other regional markets. We contracted for 20 MMcf/d of Alliance pipeline capacity to the Chicago market area that started December 2015 and is renewable on an annual evergreen basis. In 2018, we contracted an additional 40 MMcf/d of Alliance pipeline capacity starting in late 2020 for 10 years at posted tolls. In 2016, we contracted for 40,000 GJ/d of delivery service on the Nova system to the Alberta/BC border which will allow for gas exports to northern California. This service commenced in April 2018 after the Sundre Crossover project was completed by Nova. This contract has a minimum tenure of 5 years and has indefinite rights of first refusal. In 2021 Gas Transmission Northwest (GTN) triggered the ROFR process and we extended the contract for an additional 5 years to 2028. In 2017, we contracted for 44,486 GJ/d of Dawn long term fixed price delivery service that started November 2017 and has a maximum term of 10 years. The combination of these export pipeline contracts will provide for a more diverse portfolio of gas markets and prices beyond AECO. We will continue to evaluate other downstream gas marketing opportunities as they arise.

Oil and NGLs

We sell our oil and liquids production to a variety of purchasers. This enables us to benefit from specific regional advantages, while maintaining price and delivery flexibility. We are continually monitoring global and regional crude oil and NGL markets and look for opportunities to enter into price risk management contracts for up to 70% of forecast net after royalty production for the term January 1, 2022 to June 30, 2023, up to 60% for the next 18 months and up to 30% for the following 24 months. In 2021, our average realized condensate & oil price (excluding financial derivative commodity contracts) was $84.35/Bbl and our average realized price for natural gas liquids (excluding condensate) was $35.38/Bbl. For additional details on our price risk management program see Note 18 to our financial statements for the year ended December 31, 2021.

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 Montney condensate-rich natural gas play. We have entered into long-term take-or-pay contracts with minimum volume commitments 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 Montney play but we rely on third-party owned infrastructure for some of the compression, and most of the processing and transportation of our production.

For our Bilbo block of lands we have a processing, transportation and marketing agreement with Keyera Corp. for 65 MMcf/d of raw natural gas with a term that ends in early 2025. 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.

We have a processing and transportation agreement with Energy Transfer for 77 MMcf/d of raw natural gas at their Kaybob South #3 plant with a term that ends in early 2026. The gas is provided primarily from our Elmworth block of lands for this agreement. This agreement was extended from 2026 to the end of 2034 under new terms and for a volume of 50 MMcf/d.

We entered into an agreement as anchor tenant with Energy Transfer 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 annual steps reaching full capacity in the second quarter of 2023 with a term that expires in 2034. The capacity is being provided by the 200 MMcf/d gas plant at Gold Creek that began operations in early 2019. We will supply gas to this contract from the Gold Creek, Pipestone, Elmworth, and surrounding areas. In 2018 we entered into an agreement with Energy Transfer ULC to construct the Pipestone Pipeline Project to connect the Pipestone South compressor station to the new plant in Gold Creek. Transportation of raw gas started in 2019 and is contracted until late 2034 with a firm volume of 60 MMcf/d.

As part of our acquisition of Pipestone in 2018, we acquired a 39% operating working interest in the Wembley gas plant which has a total gross capacity of approximately 100 MMcf/d. Our existing Wembley and Pipestone North volumes flow through the Wembley gas plant.

We contracted for 100 MMcf/d with Veresen Midstream Limited Partnership ("**VMLP**") for firm transportation and processing for our Pipestone North block of lands. The capacity was provided by the expansion of the VMLP owned Hythe gas plant and the construction of a new sour gas pipeline connecting a portion of our Pipestone North production to the Hythe Gas Plant. This contract started in early 2021 with a ramp profile to reach the full 100 MMcf/d by 2024 with a term that ends in mid-2037.

Most of the condensate produced from our 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 2022 cash flow from operating activities and capital expenditures, and existing tax assets, we do not expect to be cash taxable in 2022. Projecting taxability beyond 2022 is subject to many uncertainties including commodity prices, capital spending, acquisitions, divestments and government regulations and guidelines. Within the context of current strip commodity prices and our capital spending plans, we expect to be taxable starting in 2024.

Costs Incurred

The following table summarizes the costs incurred related to our activities for the year ended December 31, 2021:

EXPENDITURE	YEAR ENDED DECEMBER 31, 2021 ($000s)
Property acquisition costs – Unproved properties (1)	1,000
Property acquisition costs – Proved properties	-
Exploration costs (2)	421
Development costs (3)	282,266
Other	5,159
Total	288,846

Notes:

(1) Cost of land acquired and non-producing lease rentals on those lands.

(2) Geological and geophysical capital expenditures and drilling costs for exploration wells.

(3) Development costs include development drilling costs and equipping, tie-in and facility costs for all wells, and are net of proceeds received for the funding of assets under construction by third party ownership.

Exploration and Development Activities

In 2021, we drilled 38 (38 net) condensate-rich natural gas development wells within our Montney resource play.

Subject to market conditions, in 2022, we expect to drill approximately 45 condensate-rich natural gas wells within our Montney resource play. See "*Statement of Reserves Data and Other Oil and Natural Gas Information – Other Oil and Natural Gas Information – Principal Oil and Natural Gas Properties*".

Production History

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

	QUARTER ENDED 2021				YEAR ENDED DEC 31, 2021
	MAR. 31	JUNE 30	SEPT. 30	DEC. 31	
Average Daily Production					
Light and Medium Crude Oil (Bbls/d)	287	65	13	11	93
Natural Gas (Mcf/d)	168,433	178,293	184,149	202,730	183,497
NGLs (Bbls/d) (1)	5,155	5,473	4,534	6,028	5,298
Condensate (Bbls/d) (1)	12,340	16,231	15,766	21,061	16,372
Combined (Boe/d)	45,854	51,485	51,005	60,888	52,345
Average Net Production Prices Received					
Light and Medium Crude Oil ($/Bbl)	62.54	75.66	75.52	81.10	65.82
Natural Gas ($/Mcf)	3.79	3.48	4.88	6.09	4.63
NGLs ($/Bbl) (1)	28.80	28.73	41.36	42.38	35.38
Condensate ($/Bbl) (1)	71.06	79.02	84.60	96.16	84.45
Combined ($/Boe)	36.68	40.11	47.44	57.73	46.34
Royalties Paid					
Light and Medium Crude Oil ($/Bbl)	9.21	14.89	11.04	15.99	10.46
Natural Gas ($/Mcf) (5)	-0.16	-0.29	-0.15	-0.04	-0.16
NGLs ($/Bbl) (1)	2.78	2.68	5.22	5.73	4.12
Condensate ($/Bbl) (1)	10.52	9.36	11.61	12.86	11.26
Combined ($/Boe)	2.61	2.24	3.51	4.89	3.41
Production Costs (2)(3)					
Light and Medium Crude Oil ($/Bbl)	0.07	0.01	0.00	0.00	0.02
Natural Gas ($/Mcf)	1.13	1.02	1.05	0.97	1.04
NGLs ($/Bbl) (1)	1.25	1.12	0.93	1.04	1.08
Condensate ($/Bbl) (1)	2.99	3.32	3.24	3.64	3.33
Combined ($/Boe)	11.11	10.54	10.49	10.53	10.65
Transportation Costs					
Light and Medium Crude Oil ($/Bbl)	0.51	5.77	5.26	5.77	5.00
Natural Gas ($/Mcf)	1.20	1.04	1.04	0.96	1.06
NGLs ($/Bbl) (1)	-1.17	3.34	3.46	2.98	2.18
Condensate ($/Bbl) (1)	2.92	4.62	4.27	4.92	4.32
Combined ($/Boe)	5.07	5.44	5.38	5.20	5.27
Resulting Netback (4)					
Light and Medium Crude Oil ($/Bbl)	52.75	54.99	59.22	59.34	50.34
Natural Gas ($/Mcf)	1.62	1.72	2.94	4.20	2.69
NGLs ($/Bbl) (1)	25.94	21.59	31.75	32.63	28.00
Condensate ($/Bbl) (1)	54.63	61.72	65.48	74.74	65.54
Combined ($/Boe)	17.89	21.89	28.06	37.11	27.01

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) Resulting netback is calculated by subtracting royalties, production costs and transportation from revenues. 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, 2021:

	LIGHT AND MEDIUM CRUDE OIL (Bbls/d)	NATURAL GAS LIQUIDS (Bbls/d)	CONDENSATE (1) (Bbls/d)	NATURAL GAS (Mcf/d)	TOTAL (Boe/d)
Montney	3	5,130	16,312	181,007	51,612
Non-core	90	168	60	2,491	733
Total	93	5,298	16,372	183,497	52,345

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

Production Estimates

The following table sets out the volumes of our working interest production estimated for the year ended December 31, 2022, which is reflected in the estimates of future net revenue disclosed in the forecast price tables contained above under the subheading "*Statement of Reserves Data and Other Oil and Natural Gas Information – Disclosure of Reserves Data – Reserves Data (Forecast Prices and Costs)*":

	LIGHT AND MEDIUM OIL (Bbls/d)	CONVENTIONAL NATURAL GAS (Mcf/d)	NATURAL GAS LIQUIDS (Bbls/d)	SHALE GAS (Mcf/d)	TOTAL (Boe/d)
Total Proved	-	619	28,766	246,477	69,948
Total Proved plus Probable	-	626	31,194	265,782	75,596

DIVIDENDS

We have not declared dividends on our Common Shares since November of 2010. We are currently focused upon prudent profitable growth, capital discipline, and rapid reduction of net debt. We expect to achieve enough reduction in net debt during the second quarter of 2022 to allow a portion of free adjusted funds flow to then be diverted from debt reduction for return to shareholders through either share buybacks or dividends. 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.

DESCRIPTION OF OUR CAPITAL STRUCTURE

Credit Facility

General

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 $415 million extendible revolving line of credit and a $25 million operating line of credit (collectively, the "**Credit Facility**"). The Credit Facility revolves for a two year period and, with the consent of lenders holding at least 66⅔% of the commitment amounts under the Credit Facility, may be extended for a period of up to two years. The current maturity date for the Credit Facility is May 31, 2023. 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 at the end of such two year term. 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. In May and November 2021, we completed the annual and semi-annual review of our borrowing base with our lenders with no change to the Credit Facility capacity of $440 million. The next annual review is scheduled for on or before May 31, 2022.

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.

Interest Rates

Advances under the Credit Facility are available by way of Canadian prime rate and U.S. base rate loans with interest rates between 1.75 percent and 5.25 percent over the bank's prime lending rate and bankers' acceptances, which are subject to stamping fees and margins ranging from 2.75 percent to 6.25 percent depending upon our senior funded debt to EBITDA ratio calculated at our previous quarter end.

As at December 31, 2021, our applicable pricing included a 2.00 percent per annum margin on prime loans, a 3.00 percent per annum stamping fee and margin on bankers' acceptances along with a 0.75 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. As at December 31, 2021, we had drawn $196.1 million on the Credit Facility and had outstanding letters of credit of $7.0 million which reduce the credit available on this credit facility.

The average interest rate per annum on our borrowings under our Credit Facility for the twelve months ended December 31, 2021 was 4.3% per annum.

Security and Guarantees

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 material subsidiaries and, as such, no guarantees have been provided under the Credit Agreement.

Covenants

The Credit Agreement contains customary borrowing base provisions.

The Credit Agreement contains customary negative covenants including, but not limited to, restrictions on our and our material subsidiaries' 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 and our material subsidiaries' ability to merge and consolidate with other companies or change their respective lines of business will also be restricted, 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.

Events of Default

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

Export Development Canada ("EDC") Facility

During the third quarter of 2020, we established a $40 million unsecured letter of credit facility under EDC Account Performance Security Guarantee ("**APSG**") program. In the second quarter of 2021 the letter of credit facility was reduced to $30 million. At December 31, 2021, we had outstanding letters of credit associated with the APSG of $18.1 million, leaving $11.9 million of credit available on this facility.

Senior Unsecured Notes

On July 23, 2021, we issued $230.0 million aggregate principal amount of 7.875% senior unsecured notes due July 23, 2026. The 2026 Notes were issued at $989.89 expressed as a price per $1,000.00 principal amount. Interest is payable semi-annually in arrears. The 2026 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 or financial covenants.

The 2026 Notes are non-callable by us prior to July 23, 2023. At any time on or after July 2, 2023, we may redeem all or part of the 2026 Notes at the redemption prices set forth in the table below plus any accrued and unpaid interest:

12 month period beginning on:	Percentage
July 23, 2023	103.938%
July 23, 2024	101.969%
July 23, 2025 and thereafter	100.000%

If a change of control occurs, each holder of the 2026 Notes will have the right to require us to purchase all or any part of that holder's 2026 Notes for an amount in cash equal to 101% of the aggregate principal repurchased plus accrued and unpaid interest.

On March 2, 2018, we issued $220.0 million aggregate principal amount of 6.50% senior unsecured notes due March 2, 2023. On July 23, 2021, part of the proceeds from the 2026 Notes were used to redeem the full aggregate principal amount of $220 million of the 2023 Notes, resulting in an agreed redemption call premium of $3.6 million.

Share Capital

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

Ratings

As of the date hereof, we received a corporate credit rating of B and the 2026 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 2026 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
2021			
January	1.28	0.89	22,244,222
February	2.03	1.08	29,543,334
March	2.73	1.94	39,840,022
April	2.51	2.00	22,282,046
May	3.10	2.34	32,190,904
June	4.01	2.66	30,570,251
July	4.33	3.26	14,867,697
August	3.79	2.90	16,049,972
September	5.35	3.55	18,266,749
October	6.18	5.06	16,442,398
November	7.71	6.00	24,626,155
December	7.25	5.83	16,674,159
2022			
January	8.99	6.94	24,421,184
February	9.78	8.59	20,629,970
March (1 - 28)	11.92	8.79	49,407,068

Prior Sales

During the year ended December 31, 2021, we issued a total of 0.9 million options pursuant to our stock option plan, 0.7 million restricted share awards and 1.0 million performance share awards pursuant to our share award plan and 0.1 million deferred share units pursuant to our director deferred share unit incentive plan. No funds are received by us until the options are exercised. See Note 17 of our financial statements for the year ended December 31, 2021 for a summary of stock option, restricted share award and performance share award activity.

DIRECTORS AND OFFICERS

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

NAME AND MUNICIPALITY OF RESIDENCE	POSITION WITH NUVISTA	DIRECTOR OR OFFICER SINCE	PRINCIPAL OCCUPATION
Pentti O. Karkkainen (1)(3) West Vancouver, British Columbia	Chair and Director	July 2003	Former General Partner, KERN Partners Ltd. (a private equity firm and partnership), Chair of AltaGas Ltd.
Ronald J. Eckhardt (2)(3) Calgary, Alberta	Director	March 2013	Former Executive Vice-President, North American Operations for Talisman Energy Inc., Chair of Athabasca Oil Corporation.
K.L. (Kate) Holzhauser Houston, Texas, USA	Director	December 2021	Former Vice President of Environmental, Health, Safety and Security of Chevron Phillips Chemical.
Keith A. MacPhail (2)(3) Calgary, Alberta	Director	May 2003	Chair of Cenovus Energy Inc., our former Chair and former Chair of Bonavista Energy Corporation.
Ronald J. Poelzer (1)(3) Calgary, Alberta	Director	May 2003	Former Vice Chair of Bonavista Energy Corporation.
Brian G. Shaw (1)(4) Toronto, Ontario	Director	August 2014	Director of Ovintiv Inc., Manulife Bank of Canada and Manulife Trust Company.
Sheldon B. Steeves (2)(4) Calgary, Alberta	Director	March 2013	Former CEO and Chair of Echoex Ltd., a private oil and natural gas exploration and production company. Director of Enerplus Corporation and PrairieSky Royalty Ltd.
Deborah S. Stein (1)(4) Heritage Pointe, Alberta	Director	August 2016	Former Senior Vice President Finance and Chief Financial Officer of AltaGas Ltd. Director of Aecon Group Inc., Parkland Corporation, and Trican Well Service Ltd.
Grant A. Zawalsky (4) Calgary, Alberta	Director	May 2003	Vice Chair and former Managing Partner of Burnet, Duckworth & Palmer LLP (barristers and solicitors).
Jonathan A. Wright Calgary, Alberta	President and Chief Executive Officer and a Director	May 2011	Our President and Chief Executive Officer and a Director since May 2011.
Ross L. Andreachuk Calgary, Alberta	Vice President, Finance and Chief Financial Officer and Corporate Secretary	May 2009	Our Vice President, Finance and Chief Financial Officer since September 2014. Prior thereto, Mr. Andreachuk was our Vice President and Controller.
Mike J. Lawford Calgary, Alberta	Chief Operating Officer	January 2012	Our Chief Operating Officer since December 5, 2017. Prior thereto, our Vice President, Development since January 2012.

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

Notes:
(1) Member of our Audit Committee.
(2) Member of our Reserves Committee.
(3) Member of our Corporate Governance & Compensation Committee.
(4) Member of our Environment, Social and Governance Committee.
(5) 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, 11.7 million Common Shares or 5.1% 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. Zawalsky who was a former director of Endurance Energy Ltd. (a private oil and gas company) which filed for creditor protection under the *Companies Creditors' Agreement Act* on May 30, 2016. Mr. Zawalsky resigned as a director of Endurance Energy Ltd. on November 1, 2016. Mr. Zawalsky was a director of Zargon Oil & Gas Ltd., a public company engaged in the exploitation of oil, which filed a Notice of Intention to Make a Proposal to its creditors under the provisions of Part III, Division I of the Bankruptcy and Insolvency Act (Canada) on September 8, 2020. Mr. Zawalsky resigned as a director of Zargon Oil & Gas Ltd. on September 8, 2020.

None of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us is, has, within the ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, executive officer or Shareholder.

None of our directors or executive officers (nor any personal holding company of any of such persons), or Shareholder holding a sufficient number of our securities to affect materially the control of us, has been subject to any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority or any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

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

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

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

AUDIT COMMITTEE INFORMATION

Audit Committee Charter

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

Composition of the Audit Committee

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

Deborah Stein: Corporate Director

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

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

Pentti O. Karkkainen: Independent Businessman

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

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

Ronald J. Poelzer: Independent Businessman

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

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

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

Brian G. Shaw: Independent Businessman

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

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

Pre-Approval of Policies and Procedures

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

External Auditor Service Fees

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

YEAR	AUDIT FEES [1] ($)	AUDIT-RELATED FEES [2] ($)	TAX FEES [3] ($)	ALL OTHER FEES[4] ($)
2021	390,550	107,000	17,639	21,400
2020	377,175	-	11,235	-

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 all other services provided by our external auditors other than Audit Fees, Audit-Related Fees and Tax Fees which include those related the evaluation and review of our enterprise risk management program.

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 operating in the oil and gas industry are subject to extensive regulation and control of operations (including with respect to land tenure, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government as well as with respect to the pricing and taxation of petroleum and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered by investors in the Western Canadian oil and gas industry. All current legislation is a matter of public record and we are unable to predict what additional legislation or amendments governments may enact in the future.

Our assets and operations are regulated by administrative agencies that derive their authority from legislation enacted by the applicable level of government. Regulated aspects of our upstream oil and natural gas business include all manner of activities associated with the exploration for and production of oil and natural gas, including, among other matters: (i) permits for the drilling of wells and construction of related infrastructure; (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, including by reducing emissions; (vi) storage, injection and disposal of substances associated with production operations; and (vii) the abandonment and reclamation of impacted sites. In order to conduct oil and natural gas operations and remain in good standing with the applicable federal or provincial regulatory scheme, producers must comply with applicable legislation, regulations, orders, directives and other directions (all of which are subject to governmental oversight, review and revision, from time to time). Compliance in this regard can be costly and a breach of the same may result in fines or other sanctions.

The discussion below outlines some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas industry in Western Canada, specifically in the province of Alberta, where our assets are primarily located. While these matters do not affect our operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such matters carefully.

Pricing and Marketing in Canada

Crude Oil

Oil producers are entitled to negotiate sales contracts directly with purchasers. As a result, macroeconomic and microeconomic market forces determine the price of oil. Worldwide supply and demand factors are the primary determinant of oil prices, but regional market and transportation issues also influence prices. The specific price that a producer receives will depend, in part, on oil quality, prices of competing products, distance to market, availability of transportation, value of refined products, supply/demand balance and contractual terms of sale.

Global oil markets have recovered significantly from price drops resulting from the COVID-19 pandemic. In the first quarter of 2022, oil prices have risen to the highest levels since 2014 due to tight supply and a resurgence in demand. The Organization of Petroleum Exporting Countries ("**OPEC**") forecasts robust growth in world oil demand in 2022, despite newly emerging COVID-19 variants, expected interest rate increases in major economies and other uncertainties with respect to the world economy.

In February 2022, Russian military forces invaded Ukraine. Ongoing military conflict between Russia and Ukraine has the potential to threaten the supply of oil and gas from the region. In addition, certain countries including Canada and the United States have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy in addition to the near term effects on Russia. The long-term impacts of the conflict remain uncertain.

Natural Gas

Negotiations between buyers and sellers determine the price of natural gas sold in intra-provincial, interprovincial and international trade. The price received by a natural gas producer depends, in part, on the price of competing natural gas supplies and other fuels, natural gas quality, distance to market, availability of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms of sale.

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. The profitability of NGLs extracted from natural gas is based on the products extracted being of greater economic value as separate commodities than as components of natural gas and therefore commanding higher prices. Such prices depend, in part, on the quality of the NGLs, price of competing chemical stock, distance to market, access to downstream transportation, length of contract term, supply/demand balance and other contractual terms of sale.

Exports from Canada

The Canada Energy Regulator (the "**CER**") regulates the export of oil, natural gas and NGLs from Canada through the issuance of short-term orders and longer-term licences pursuant to its authority under the *Canadian Energy Regulator Act* (the "**CERA**"). Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts continue to meet certain criteria prescribed by the CER and the federal government. We do not directly enter into contracts to export our production outside of Canada.

Transportation Constraints and Market Access

Under the Canadian Constitution, the development and operation of interprovincial and international pipelines fall within the federal government's jurisdiction and, under the CERA, new interprovincial and international pipelines require a federal regulatory review and Cabinet approval before they can proceed. However, recent years have seen a perceived lack of policy and regulatory certainty in this regard such that, even when projects are approved, they often face delays due to actions taken by provincial and municipal governments and legal opposition related to issues such as Indigenous rights and title, the government's duty to consult and accommodate Indigenous peoples and the sufficiency of all relevant environmental review processes. Export pipelines from Canada to the United States face additional unpredictability as such pipelines also require approvals from several levels of government in the United States.

Producers negotiate with pipeline operators to transport their products to market on a firm, spot or interruptible basis depending on the specific pipeline and the specific substance. Transportation availability is highly variable across different jurisdictions and regions. This variability can determine the nature of transportation commitments available, the number of potential customers and the price received.

Oil Pipelines

Specific Pipeline Updates

The Enbridge Inc. ("**Enbridge**") Line 3 Replacement from Hardisty, Alberta to Superior, Wisconsin came into service in October 2021. The Line 3 Replacement, originally expected to be in-service in late 2019, faced significant permitting difficulties in the United States, resulting in the two-year delay. The pipeline provides an incremental 370,000 Bbls/d of export capacity from Western Canada into the United States.

The Trans Mountain Pipeline expansion received Cabinet approval in November 2016. Following a period of political opposition in British Columbia, the federal government acquired the Trans Mountain Pipeline in August 2018. Following the resolution of a number of legal challenges and a second regulatory hearing, construction on the Trans Mountain Pipeline expansion commenced in late 2019. Earlier estimated at $12.6 billion, the project budget has risen to $21.4 billion as of February 2022. The pipeline is expected to be in service in the third quarter of 2023, an extension from Trans Mountain's December 2022 estimate. The budget increase and in-service date delay have been attributed to, among other things, the ongoing effects of the COVID-19 pandemic and the widespread flooding in British Columbia in late 2021.

In November 2020, the Attorney General of Michigan filed a lawsuit to terminate an easement that allows the Enbridge Line 5 pipeline system to operate below the Straits of Mackinac, attempting to force the lines comprising this segment of the pipeline system to be shut down. Enbridge filed a federal complaint in late November 2020 in the United States District Court for the Western District of Michigan and is seeking an injunction to prevent the termination of the easement. Enbridge stated in January 2021 that it intends to defy the shut down order, as the dual pipelines are in full compliance with U.S. federal safety standards. The Government of Canada invoked a 1977 treaty with the United States on October 4, 2021, triggering bilateral negotiations over the pipeline. On December 15, 2021, Enbridge moved to transfer the Attorney General's lawsuit from Michigan State Court to United States Federal Court.

Marine Tankers

The *Oil Tanker Moratorium Act*, which was enacted in June 2019, imposes a ban on tanker traffic transporting crude oil or persistent crude oil products in excess of 12,500 metric tonnes to and from ports located along British Columbia's north coast. The ban may prevent pipelines being built to, and export terminals being located on, the portion of the British Columbia coast subject to the moratorium.

Natural Gas and LNG

Natural gas prices in Western Canada have been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Companies that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access more markets and obtain better pricing. Companies without firm access may be forced to accept spot pricing in Western Canada for their natural gas, which is generally lower than the prices received in other North American markets.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to reduced capacity and apportionment of access, the effects of which have been exacerbated by storage limitations. In October 2020, TC Energy received federal approval to expand the NGTL System and the expanded NGTL System is expected to be fully operational by April 2022.

Specific Pipeline and Proposed LNG Export Terminal Updates

While a number of LNG export plants have been proposed in Canada, regulatory and legal uncertainty, social and political opposition and changing market conditions have resulted in the cancellation or delay of many of these projects. Nonetheless, in October 2018, the joint venture partners of the LNG Canada LNG export terminal announced a positive final investment decision. Once complete, the project will allow producers in northeastern British Columbia to transport natural gas to the LNG Canada liquefaction facility and export terminal in Kitimat, British Columbia via the Coastal GasLink pipeline (the "**CGL Pipeline**"). Pre-construction activities on the LNG Canada facility began in November 2018, with a completion target of 2025.

In May 2020, TC Energy sold a 65% equity interest in the CGL Pipeline to investment companies KKR & Co Inc. and Alberta Investment Management Corporation while remaining the pipeline operator. Despite its approval, the CGL Pipeline has faced legal and social opposition. For example, protests involving the Hereditary Chiefs of the Wet'suwet'en First Nation and their supporters have delayed construction activities on the CGL Pipeline, although construction is proceeding. As of December 2021, construction of the CGL Pipeline is approximately 60% complete.

In addition to LNG Canada and the CGL Pipeline projects, a number of other LNG projects are underway at varying stages of progress, though none have reached a positive final investment decision.

International Trade Agreements

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the Comprehensive Economic and Trade Agreement, the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the United States Mexico Canada Agreement (the "**USMCA**"), which replaced the former North American Free Trade Agreement ("**NAFTA**") on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the implementation of the USMCA could impact Western Canada's oil and gas industry at large, including our business.

While the proportionality rules in Article 605 of NAFTA previously prevented Canada from implementing policies that limit exports to the United States and Mexico relative to the total supply produced in Canada, the USMCA does not contain the same proportionality requirements. This may allow Canadian producers to develop a more diversified export portfolio than was possible under NAFTA, subject to the construction of infrastructure allowing more Canadian production to reach eastern Canada, Asia and Europe.

Land Tenure

Mineral rights

With the exception of Manitoba, each provincial government in Western Canada owns most of the mineral rights to the oil and natural gas located within their respective provincial borders. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits (collectively, "**leases**") for varying terms, and on conditions set forth in provincial legislation, including requirements to perform specific work or make payments in lieu thereof. The provincial governments in Western Canada conduct regular land sales where oil and natural gas companies bid for the leases necessary to explore for and produce oil and natural gas owned by the respective provincial governments. These leases generally have fixed terms, but they can be continued beyond their initial terms if the necessary conditions are satisfied.

All of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deep, non-productive geological formations at the conclusion of the primary term of a disposition. In addition, Alberta has a policy of "shallow rights reversion" which provides for the reversion to the Crown of mineral rights to shallow, non-productive geological formations for new leases and licences.

In addition to Crown ownership of the rights to oil and natural gas, private ownership of oil and natural gas (i.e. freehold mineral lands) also exists in Western Canada. Rights to explore for and produce privately owned 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 companies seeking to explore for and/or develop oil and natural gas reserves.

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 manages subsurface and surface leases in consultation with applicable Indigenous peoples, for the exploration and production of oil and natural gas on Indigenous reservations through *An Act to Amend the Indian Oil and Gas Act* and the accompanying regulations. We do not have active operations on Indigenous reserve lands.

Surface rights

To develop oil and natural gas resources, producers must also have access rights to the surface lands required to conduct operations. For Crown lands, surface access rights can be obtained directly from the government. For private lands, access rights can be negotiated with the landowner. Where an agreement cannot be reached, however, each province has developed its own process that producers can follow to obtain and maintain the surface access necessary to conduct operations throughout the lifespan of a well, including notification requirements and providing compensation to affected persons for lost land use and surface damage. Similar rules apply to facility and pipeline operators.

Royalties and Incentives

General

Each province has legislation and regulations in place to govern Crown royalties and establish the royalty rates that producers must pay in respect of the production of Crown resources. The royalty regime in a given province is in addition to applicable federal and provincial taxes and is a significant factor in the profitability of oil sands projects and oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are negotiated between the mineral freehold owner and the lessee, though certain provincial taxes and other charges on production or revenues may be payable.

Producers and working interest owners of oil and natural gas rights may create additional royalties or royalty-like interests, such as overriding royalties, net profits interests and net carried interests, through private transactions, the terms of which are subject to negotiation.

Occasionally, the provincial governments in Western Canada create incentive programs for the oil and gas industry. These programs often provide for volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits and may be introduced when commodity prices are low to encourage exploration and development activity. Governments may also introduce incentive programs to encourage producers to prioritize certain kinds of development or utilize technologies that may enhance or improve recovery of oil, natural gas and NGLs, or improve environmental performance. In addition, from time-to-time, including during the COVID-19 pandemic, the federal government has created incentives and other financial aid programs intended to assist businesses operating in the oil and gas industry as well as other industries in Canada.

Alberta

Crown royalties

In Alberta, oil and natural gas producers are responsible for calculating their royalty rate on an ongoing basis. The Crown's royalty share of production is payable monthly and producers must submit their records showing the royalty calculation.

In 2016, the Government of Alberta adopted a modernized Crown royalty framework (the "**Modernized Framework**") that applies to all conventional oil (i.e., not oil sands) and natural gas wells drilled after December 31, 2016 that produce Crown-owned resources. The previous royalty framework (the "**Old Framework**") will continue to apply to wells producing Crown-owned resources that were drilled prior to January 1, 2017 until December 31, 2026, following which time they will become subject to the Modernized Framework. The *Royalty Guarantee Act* (Alberta), came into effect on July 18, 2019, and provides that no major changes will be made to the current oil and natural gas royalty structure for a period of at least 10 years.

Royalties on production from wells subject to the Modernized Framework are determined on a "revenue-minus-costs" basis. The cost component is based on a Drilling and Completion Cost Allowance formula that relies, in part, on the industry's average drilling and completion costs, determined annually by the Alberta Energy Regulator (the "**AER**"), and incorporates information specific to each well such as vertical depth and lateral length.

Under the Modernized Framework, producers initially pay a flat royalty of 5% on production revenue from each producing well until payout, which is the point at which cumulative gross revenues from the well equals the applicable Drilling and Completion Cost Allowance. After payout, producers pay an increased royalty of up to 40% on oil and condensate or 36% on natural gas that will vary depending on the nature of the resource and market prices. Once the rate of production from a well is too low to sustain the full royalty burden, its royalty rate is gradually adjusted downward as production declines, eventually reaching a floor of 5%.

Under the Old Framework, royalty rates for conventional oil production can be as high as 40% and royalty rates for natural gas production can be as high as 36%. Similar to the Modernized Framework, these rates vary based on the nature of the resource and market prices. The natural gas royalty formula also provides for a reduction based on the measured depth of the well, as well as the acid gas content of the produced gas.

In addition to royalties, producers of oil and natural gas from Crown lands in Alberta are also required to pay annual rentals to the Government of Alberta.

Freehold royalties and taxes

Royalty rates for the production of privately owned oil and natural gas are negotiated between the producer and the resource owner.

The Government of Alberta levies annual freehold mineral taxes for production from freehold mineral lands. On average, the tax levied in Alberta is 4% of revenues reported from freehold mineral title properties and is payable by the registered owner of the mineral rights.

Regulatory Authorities and Environmental Regulation

General

The Canadian oil and gas industry is 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 oil and gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well, facility and pipeline sites.

Compliance with such regulations can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability, and the imposition of material fines and penalties. In addition, future changes to environmental legislation, including legislation related to air pollution and GHG emissions (typically measured in terms of their global warming potential and expressed in terms of CO2e, may impose further requirements on operators and other companies in the oil and gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the federal government can regulate environmental matters where they impact matters of federal jurisdiction or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including pipelines and railways, and activities carried out on federal lands. Where there is a direct conflict between federal and provincial environmental legislation in relation to the same matter, the federal law prevails.

The CERA and the Impact Assessment Act (the "**IAA**") provide a number of important elements to the regulation of federally regulated major projects and their associated environmental assessments. The CERA separates the CER's administrative and adjudicative functions. The CER has jurisdiction over matters such as the environmental and economic regulation of pipelines, transmission infrastructure and certain offshore renewable energy projects. In its adjudicative role, the CERA tasks the CER with reviewing applications for the development, construction and operation of many of these projects, culminating in their eventual abandonment.

The IAA relies on a designated project list as a trigger for a federal assessment. Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the Impact Assessment Agency (the "**IA Agency**") or, in the case of certain pipelines, a joint review panel comprised of members from the CER and the IA Agency. The impact assessment requires consideration of the project's potential adverse effects and the overall societal impact that a project may have, both of which may include a consideration of, among other items, environmental, biophysical and socio-economic factors, climate change, and impacts to Indigenous rights. It also requires an expanded public interest assessment. Designated projects specific to the oil and gas industry include pipelines that require more than 75km of new rights of way and pipelines located in national parks, large scale in situ oil sands projects not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

The federal government has stated that an objective of the legislative changes was to improve decision certainty and turnaround times. Once a review or assessment is commenced under either the CERA or IAA, there are limits on the amount of time the relevant regulatory authority will have to issue its report and recommendation. Designated projects will go through a planning phase to determine the scope of the impact assessment, which the federal government has stated should provide more certainty as to the length of the full review process.

The Government of Alberta has submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA, but this matter remains before the courts.

Alberta

The AER is the principal regulator responsible for all energy resource development in Alberta. It derives its authority from the *Responsible Energy Development Act* and a number of related statutes including the *Oil and Gas Conservation Act* (the "**OGCA**"), the *Oil Sands Conservation Act*, the *Pipeline Act*, and the *Environmental Protection and Enhancement Act*. The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources, including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission and the Surface Rights Board, as well as the Alberta Ministry of Energy's responsibility for mineral tenure.

The Government of Alberta relies on regional planning to accomplish its 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. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Parks, the Alberta Ministry of Energy, the Aboriginal Consultation Office and the Land Use Secretariat.

The Government of Alberta's land-use policy 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.

The AER monitors seismic activity across Alberta to assess the risks associated with, and instances of, earthquakes induced by hydraulic fracturing. Hydraulic fracturing involves the injection of water, sand or other proppants and additives under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate oil and natural gas production. We routinely conduct hydraulic fracturing in our drilling and completion programs. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place, prompting regulatory authorities to investigate the practice further.

The AER has developed monitoring and reporting requirements that apply to all oil and natural gas producers working in certain areas where the likelihood of an earthquake is higher, and implemented the requirements in *Subsurface Order Nos. 2*, *6*, and *7*. The regions with seismic protocols in place are Fox Creek, Red Deer, and Brazeau (the "**Seismic Protocol Regions**"). We do not have active operations in these areas. Oil and natural gas producers in each of the Seismic Protocol Regions are subject to a "traffic light" reporting system that sets thresholds on the Richter scale of earthquake magnitude. The thresholds vary among the Seismic Protocol Regions and trigger a sliding scale of obligations from the oil or natural gas producers operating there. Such obligations range from no action required, to informing the AER and invoking an approved response plan, to ceasing operations and informing the AER. The AER has the discretion to suspend operations while it investigates following a seismic event until it has assessed the ongoing risk of earthquakes in a specific area and/or may require the operator to update its response plan. The AER may extend these requirements to other areas of Alberta if necessary, subject to the results of its ongoing province-wide monitoring.

Liability Management

Alberta

The AER administers the Liability Management Framework (the "**AB LM Framework**") and the Liability Management Rating Program (the "**AB LMR Program**") to manage liability for most conventional upstream oil and natural gas wells, facilities and pipelines in Alberta. The AER is in the process of replacing the AB LMR Program with the AB LM Framework. This change was effected under key new AER directives in 2021. Broadly, the AB LM Framework is intended to provide a more holistic approach to liability management in Alberta, as the AER found that the more formulaic approach under the AB LMR Program did not necessarily indicate whether a company could meet its liability obligations. New developments under the AB LM Framework include a new Licensee Capability Assessment System (the "**AB LCA**"), a new Inventory Reduction Program (the "**AB IR Program**"), and a new Licensee Management Program ("**AB LM Program**"). Meanwhile, some programs under the AB LMR Program remain in effect, including the Oilfield Waste Liability Program (the "**AB OWL Program**"), the Large Facility Liability Management Program (the "**AB LF Program**") and elements of the Licensee Liability Rating Program (the "**AB LLR Program**"). The mix between active programs under the AB LM Framework and the AB LMR Program highlights the transitional and dynamic nature of liability management in Alberta. While the province is moving towards the AB LM Framework and a more holistic approach to liability management, the AER has noted that this will be a gradual process that will take time to complete. In the meantime, the AB LMR Program continues to play an important role in Alberta's liability management scheme.

Complementing the AB LM Framework and the AB LMR Program, Alberta's OGCA establishes an orphan fund (the "**Orphan Fund**") to help pay the costs to suspend, abandon, remediate and reclaim a well, facility or pipeline included in the AB LLR Program and the AB OWL Program if a licensee or working interest participant becomes insolvent or is unable to meet its obligations. Licensees in the AB LLR Program and the AB OWL Program fund the Orphan Fund through a levy administered by the AER. However, given the increase in orphaned oil and natural gas assets, the Government of Alberta has loaned the Orphan Fund approximately $335 million to carry out abandonment and reclamation work. In response to the COVID-19 pandemic, the Government of Alberta also covered $113 million in levy payments that licensees would otherwise have owed to the Orphan Fund, corresponding to the levy payments due for the first six months of the AER's fiscal year. A separate orphan levy applies to persons holding licences subject to the AB LF Program. Collectively, these programs are designed to minimize the risk to the Orphan Fund posed by the unfunded liabilities of licensees and to prevent the taxpayers of Alberta from incurring costs to suspend, abandon, remediate and reclaim wells, facilities or pipelines.

The Supreme Court of Canada's decision in *Orphan Well Association v Grant Thornton* (also known as the "**Redwater**" decision), provides the backdrop for Alberta's approach to liability management. As a result of the Redwater decision, receivers and trustees can no longer avoid the AER's legislated authority to impose abandonment orders against licensees or to require a licensee to pay a security deposit before approving a licence transfer when any such licensee is subject to formal insolvency proceedings. This means that insolvent estates can no longer disclaim assets that have reached the end of their productive lives (and therefore represent a net liability) in order to deal primarily with the remaining productive and valuable assets without first satisfying any abandonment and reclamation obligations associated with the insolvent estate's assets. In April 2020, the Government of Alberta passed the *Liabilities Management Statutes Amendment Act*, which places the burden of a defunct licensee's abandonment and reclamation obligations first on the defunct licensee's working interest partners, and second, the AER may order the Orphan Fund to assume care and custody and accelerate the clean-up of wells or sites which do not have a responsible owner. These changes came into force in June 2020.

One important step in the shift to the AB LM Framework has been amendments to *Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals* ("**Directive 067**"), which deals with licensee eligibility to operate wells and facilities. All licence transfers and granting of new well, facility and pipeline licences in Alberta are subject to AER approval. Previously under the AB LMR Program, as a condition of transferring existing AER licences, approvals and permits, all transfers required transferees to demonstrate that they had a liability management rating of 2.0 or higher immediately following the transfer. If transferees did not have the required rating, they would have to otherwise prove to the satisfaction of the AER that they could meet their abandonment and reclamation obligations, through means such as posting security or reducing their existing obligations. However, amendments from April 2021 to Directive 067 expanded the criteria for assessing licensee eligibility. Notably, the recent amendments increase requirements for financial disclosure, detail new requirements for when a licensee poses an "unreasonable risk" of orphaning assets, and adds additional general requirements for maintaining eligibility.

Alongside changes to Directive 067, the AER also introduced *Directive 088: Licensee Life-Cycle Management* ("**Directive 088**") in December 2021 under the AB LM Framework. Directive 088 replaces, to an extent, the AB LLR Program with the AB LCA. Whereas the AB LLR Program previously assessed a licensee based on a liability rating determined by the ratio of a licensee's deemed asset value relative to the deemed liability value of its oil and gas wells and facilities, the AB LCA now considers a wider variety of factors and is intended to be a more comprehensive assessment of corporate health. Such factors are wide reaching and include: (i) a licensee's financial health; (ii) its established total magnitude of liabilities, (iii) the remaining lifespan of its mineral resources; (iv) the management of its operations; (v) the rate of closure activities for its liabilities; and (vi) and its compliance with administrative and regulatory requirements. These various factors then feed into a broader holistic assessment of a licensee under the AB LM Framework. In turn, that holistic assessment provides the basis for assessing risk posed by licence transfers, as well as any security deposit that the AER may require from a licensee in the event that the regulator deems a licensee at risk of not being able to meet its liability obligations. However, the liability management rating under the LLR Program is still in effect for other liability management programs such as the AB OWL Program and the AB LF Program, and will remain in effect until a broadened scope of Directive 088 is phased in over time.

In addition to the AB LCA, Directive 088 also implemented other new liability management programs under the AB LM Framework. These include the AB LM Program and the AB IR Program. Under the AB LM Program the AER will continuously monitor licensees over the life-cycle of a project. If, under the AB LM Program, the AER identifies a licensee as high risk, the regulator may employ various tools to ensure that a licensee meets its regulatory and liability obligations. In addition, under the AB IR Program the AER sets industry wide spending targets for abandonment and reclamation activities. Licensees are then assigned a mandatory licensee specific target based on the licensee's proportion of provincial inactive liabilities and the licensee's level of financial distress. Certain licensees may also elect to provide the AER with a security deposit in place of their closure spend target.

The Government of Alberta followed the announcement of the AB LM Framework with amendments to the *Oil and Gas Conservation Rules* and the *Pipeline Rules* in late 2020. The changes to these rules fall into three principal categories: (i) they introduce "closure" as a defined term, which captures both abandonment and reclamation; (ii) they expand the AER's authority to initiate and supervise closure; and (iii) they permit qualifying third parties on whose property wells or facilities are located to request that licensees prepare a closure plan.

To address abandonment and reclamation liabilities in Alberta, the AER also implements, from time to time, programs intended to encourage the decommissioning, remediation and reclamation of inactive or marginal oil and natural gas infrastructure. In 2018, for example, the AER announced a voluntary area-based closure ("**ABC**") program. The ABC program was designed to reduce the cost of abandonment and reclamation operations through industry collaboration and economies of scale. Parties seeking to participate in the program were required commit to an inactive liability reduction target to be met through closure work of inactive assets.

Federal and Provincial Support for Liability Management

As part of an announcement of federal relief for Canada's oil and gas industry in response to COVID-19, in May 2020 the federal government pledged $1.72 billion to clean up orphan and inactive wells in Alberta, Saskatchewan and British Columbia. These funds were administered by regulatory authorities in each province and disbursed through various provincial programs. The majority of these funds have now been allocated and disbursed.

Climate Change Regulation

Climate change regulation at each of the international, federal and provincial levels has the potential to significantly affect the future of the oil and gas industry in Canada. These impacts are uncertain and it is not possible to predict what future policies, laws and regulations will entail. Any new laws and regulations (or additional requirements to existing laws and regulations) could have a material impact on our operations and cash from operating activities.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change (the "**UNFCCC**") since 1992. Since its inception, the UNFCCC has instigated numerous policy changes with respect to climate governance. On April 22, 2016, 197 countries, including Canada, signed the Paris Agreement, committing to prevent global temperatures from rising more than 2° Celsius above pre-industrial levels and to pursue efforts to limit this rise to no more than 1.5° Celsius. To date, 189 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In 2016, Canada committed to reducing its emissions by 30% below 2005 levels by 2030. In 2021, Canada updated its original commitment by pledging to reduce emissions by 40-45% below 2005 levels by 2030, and to net-zero by 2050.

During the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact, including: (i) reducing methane emissions in the oil and gas sector to 75% of 2012 levels by 2030; (ii) ceasing export of thermal coal by 2030; (iii) imposing a cap on emissions from the oil and gas sector; (iv) halting direct public funding to the global fossil fuel sector by the end of 2022; and (v) committing that all new vehicles sold in the country will be zero-emission on or before 2040.

The Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change in 2016, setting out a plan to meet the federal government's 2030 emissions reduction targets. On June 21, 2018, the federal government enacted the Greenhouse Gas Pollution Pricing Act (the "**GGPPA**"), which came into force on January 1, 2019. This regime has two parts: an output-based pricing system ("**OBPS**") for large industry (enabled by the Output-Based Pricing System Regulations) and a fuel charge (enabled by the Fuel Charge Regulations), both of which impose a price on CO2e emissions. This system applies in provinces and territories that request it and in those that do not have their own equivalent emissions pricing systems in place that meet the federal standards and ensure that there is a uniform price on emissions across the country. Originally under the federal plans, the price was set to escalate by $10 per year until it reaches a maximum price of $50/tonne of CO2e in 2022; however, on December 11, 2020, the federal government announced its intention to continue the annual price increases beyond 2022, such that, commencing in 2023, the benchmark price per tonne of CO2e will increase by $15 per year until it reaches $170/tonne of CO2e in 2030. Starting April 1, 2022, the minimum price permissible under the GGPPA is $50/tonne of CO2e. In addition, on March 5, 2021, the federal government introduced for comment the Greenhouse Gas Offset Credit System Regulations (Canada) (the "**Federal Offset Credit Regulations**"). The proposed Federal Offset Credit Regulations are intended to establish a regulatory framework to allow certain kinds of projects to generate and sell offset credits for use in the federal OBPS. The final Federal Offset Credit Regulations are currently targeted for publication in mid-2022.

While several provinces challenged the constitutionality of the GGPPA following its enactment, the Supreme Court of Canada confirmed its constitutional validity in a judgment released on March 25, 2021.

On April 26, 2018, the federal government passed the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector) (the "**Federal Methane Regulations**"). The Federal Methane Regulations seek to reduce emissions of methane from the oil and natural gas sector, and came into force on January 1, 2020. By introducing a number of new control measures, the Federal Methane Regulations aim to reduce unintentional leaks and the intentional venting of methane and ensure that oil and natural gas operations use low-emission equipment and processes. Among other things, the Federal Methane Regulations limit how much methane upstream oil and natural gas facilities are permitted to vent. The federal government anticipates that these actions will reduce annual GHG emissions by about 20 megatonnes by 2030.

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

As part of its efforts to provide relief to Canada's oil and gas industry in light of the COVID-19 pandemic, the federal government announced the $750 million Emissions Reduction Fund ("**ERF**"), intended to help the oil and gas sectors to reduce the production of methane and other GHG emissions. Funds disbursed through the ERF will primarily take the form of repayable contributions to onshore and offshore oil and gas firms. Of the $750 million in funding, $675 million was allocated to the Onshore Deployment Program, while $75 million was dedicated to the Offshore Deployment Program and the Offshore RD&D (research, development and demonstration) Program. Natural Resources Canada expects that all funding for onshore projects will be allocated by March 2022, while funding for offshore projects will be allocated by March 2023.

The federal government has also announced that it will implement a Clean Fuel Standard that will require producers, importers and distributors to reduce the emissions intensity of liquid fuels. It is expected that the applicable regulations will come into force in December 2022.

In the November 23, 2021 Speech from the Throne, the federal government restated its commitment to achieve net-zero emission by 2050. In pursuit of this objective, the government's proposed actions include: (i) moving to cap and cut oil and gas sector emissions; (ii) investing in public transit and mandating the sale of zero-emission vehicles; (iii) increasing the federally imposed price on pollution; (iv) investing in the production of cleaner steel, aluminum, building products, cars, and planes; (v) addressing the loss of biodiversity by continuing to strengthen partnerships with First Nations, Inuit, and

Métis, to protect nature and the traditional knowledge of those groups; (vi) creating a Canada Water Agency to safeguard water as a natural resource and support Canadian farmers; (vii) strengthening action to prevent and prepare for floods, wildfires, droughts, coastline erosion, and other extreme weather worsened by climate change; and (viii) helping build back communities impacted by extreme weather events through the development of Canada's first-ever National Adaptation Strategy.

The *Canadian Net-Zero Emissions Accountability Act* (the "**CNEAA**") received royal assent on June 29, 2021, and came into force on the same day. The CNEAA binds the Government of Canada to a process intended to help Canada achieve net-zero emissions by 2050. It establishes rolling five-year emissions-reduction targets and requires the government to develop plans to reach each target and support these efforts by creating a Net-Zero Advisory Body. The CNEAA also requires the federal government to publish annual reports that describe how departments and crown corporations are considering the financial risks and opportunities of climate change in their decision-making. A comprehensive review of the Act is required every five years from the date the Act came into force.

The Government of Canada is also in the midst of developing a carbon capture utilization and storage ("**CCUS**") strategy. CCUS is a technology that captures carbon dioxide from facilities, including industrial or power applications, or directly from the atmosphere. The captured carbon dioxide is then compressed and transported for permanent storage in underground geological formations or used to make new products such as concrete. The federal government has indicated that urgent steps are necessary to ramp up CCUS in Canada, as this will be a critical element of the plan to reach net-zero by 2050.

Alberta

In December 2016, the *Oil Sands Emissions Limit Act* came into force, establishing an annual 100 megatonne limit for GHG emissions from all oil sands sites, but the regulations necessary to enforce the limit have not yet been developed. The delay in drafting these regulations has been inconsequential thus far, as Alberta's oil sands emit roughly 70 megatonnes of GHG emissions per year, well below the 100 megatonne limit.

In June 2019, the fuel charge element of the federal backstop program took effect in Alberta. On April 1, 2022, the carbon tax payable in Alberta will increase from $40 to $50 per tonne of CO2e, and will continue to increase at a rate of $15 per year until it reaches $170 per tonne in 2030. In December 2019, the federal government approved Alberta's *Technology Innovation and Emissions Reduction* ("**TIER**") regulation, which applies to large emitters. The TIER regulation came into effect on January 1, 2020 and replaces the previous *Carbon Competitiveness Incentives Regulation*. The TIER regulation meets the federal benchmark stringency requirements for emissions sources covered in the regulation, but the federal backstop continues to apply to emissions sources not covered by the regulation.

The TIER regulation applies to emitters that emit more than 100,000 tonnes of CO2e per year in 2016 or any subsequent year. The initial target for most TIER-regulated facilities is to reduce emissions intensity by 10% as measured against that facility's individual benchmark, with a further 1% reduction in each subsequent year. The facility-specific benchmark does not apply to all facilities, such as those in the electricity sector, which are compared against the good-as-best-gas standard. Similarly, for facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available. Under the TIER regulation, certain facilities in high-emitting or trade exposed sectors can opt-in to the program in specified circumstances if they do not meet the 100,000 tonne threshold. To encourage compliance with the emissions intensity reduction targets, TIER-regulated facilities must provide annual compliance reports. Facilities that are unable to achieve their targets may either purchase credits from other facilities, purchase carbon offsets, or pay a levy to the Government of Alberta.

On September 1, 2020, the Government of Alberta announced $750 million in spending from the TIER fund to support projects that help industries reduce their carbon emissions. Such projects include CCUS, energy efficiency, and increased methane management initiatives. An additional $176 million in spending from the TIER fund was announced for similar GHG reduction projects on November 1, 2021.

The Government of Alberta aims to lower annual methane emissions by 45% by 2025. The Government of Alberta enacted the *Methane Emission Reduction Regulation* on January 1, 2020, and the AER simultaneously released an updated edition of *Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting*. The release of the updated Directive 060 complements a previously released update to *Directive 017: Measurement Requirements for Oil and Gas Operations* that took effect in December 2018. In November 2020, the Government of Canada and the Government of Alberta announced an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in Alberta.

Indigenous Rights

Constitutionally mandated government-led consultation with and, if applicable, accommodation of, the rights of Indigenous groups impacted by regulated industrial activity, as well as proponent-led consultation and accommodation or benefit sharing initiatives, play an increasingly important role in the Western Canadian oil and gas industry. In addition, Canada is a signatory to the United Nations Declaration of the Rights of Indigenous Peoples ("**UNDRIP**") and the principles set forth therein may continue to influence the role of Indigenous engagement in the development of the oil and gas industry in Western Canada. For example, in November 2019, the *Declaration on the Rights of Indigenous Peoples Act* ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with UNDRIP. In June 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* ("**UNDRIP Act**") came into force in Canada. Similar to British Columbia's DRIPA, the UNDRIP Act requires the Government of Canada to take all measures necessary to ensure the laws of Canada are consistent with the principles of UNDRIP and to implement an action plan to address UNDRIP's objectives.

Continued development of common law precedent regarding existing laws relating to Indigenous consultation and accommodation as well as the adoption of new laws such as DRIPA and UNDRIP Act are expected to continue to add uncertainty to the ability of entities operating in the Canadian oil and gas industry to execute on major resource development and infrastructure projects, including, among other projects, pipelines. The Government of Canada has expressed that implementation of the UNDRIP Act has the potential to make meaningful change in how Indigenous peoples collaborate in impact assessment moving forward, but has confirmed that the current IAA already establishes a framework that aligns with UNDRIP and does not need to be changed in light of the UNDRIP Act.

On June 29, 2021, the British Columbia Supreme Court issued a judgement in *Yahey v British Columbia* (the "**Blueberry Decision**"), in which it determined that the cumulative impacts of industrial development on the traditional territory of the Blueberry River First Nation ("**BRFN**") in northeast British Columbia had breached the BRFN's rights guaranteed under Treaty 8. Going forward, the Blueberry Decision may have significant impacts on the regulation of industrial activities in northeast British Columbia. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties.

On October 7, 2021, the Government of British Columbia and the BRFN reached an initial agreement in response to the Blueberry Decision in which the parties agreed to negotiate a land management process for BRFN territory, and certain previously authorized forestry and oil and gas projects were put on hold pending further negotiation. Currently, the Government of British Columbia and the BRFN are in the midst of negotiations to finalize a new regime for assessment, authorization and management of industrial activities on BRFN territory in a manner consistent with the Blueberry Decision. The BRFN elected Judy Desjarlais as Chief in January 2022, replacing Marvin Yahey Sr. in the role. The long-term impacts and risks of the Blueberry Decision and the election of a new BRFN Chief on the Canadian oil and gas industry remain uncertain.

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.

Impacts of Pandemics

In March 2020, the World Health Organization declared COVID-19 a global pandemic, prompting many countries around the world to close international borders and order the closure of institutions and businesses deemed non-essential. This resulted in a swift and significant reduction in economic activity in Canada and internationally along with a sudden drop in demand for oil, liquids and natural gas. Since 2020, oil prices have largely recovered from their historic lows, but price support from future demand remains uncertain as countries experience varying degrees of virus outbreak and newly emerging virus variants following efforts to re-open local economies and international borders. Low commodity prices resulting from reduced demand associated with the impact of COVID-19 has had, and may continue to have, a negative impact on our operational results and financial condition. Low prices for oil, liquids and natural gas will reduce our cash from operating activities, and impact our level of capital investment and may result in the reduction of production at certain producing properties.

While the duration and full impact of the COVID-19 pandemic is not yet known, effects of COVID-19 may also include disruptions to production operations, access to materials and services, increased employee absenteeism from illness, and temporary closures of our facilities.

The extent to which our operational and financial results are affected by COVID-19 will depend on various factors and consequences beyond our control such as the duration and scope of the pandemic; additional actions taken by business and government in response to the pandemic, and the speed and effectiveness of responses to combat the virus. Additionally, COVID-19 and its effect on local and global economic conditions stemming from the pandemic could also aggravate the other risk factors identified herein, the extent of which is not yet known.

Climate Change

Global climate issues continue to attract public and scientific attention. Numerous reports, including reports from the Intergovernmental Panel on Climate Change, have engendered concern about the impacts of human activity, especially hydrocarbon combustion, on global climate issues. In turn, increasing public, government, and investor attention is being paid to global climate issues and to emissions of GHG, including emissions of carbon dioxide and methane from the production and use of oil, liquids and natural gas. The majority of countries across the globe, including Canada, have agreed to reduce their carbon emissions in accordance with the Paris Agreement. In addition, during the course of the 2021 United Nations Climate Change Conference in Glasgow, Scotland, Canada's Prime Minister Justin Trudeau made several pledges aimed at reducing Canada's GHG emissions and environmental impact. As discussed below, we face both transition risks and physical risks associated with climate change and climate change policy and regulations.

Transition risks

Foreign and domestic governments continue to evaluate and implement policy, legislation, and regulations focused on restricting emissions commonly referred to as GHG emissions and promoting adaptation to climate change and the transition to a low-carbon economy. It is not possible to predict what measures foreign and domestic governments may implement in this regard, nor is it possible to predict the requirements that such measures may impose or when such measures may be implemented. However, international multilateral agreements, the obligations adopted thereunder and legal challenges concerning the adequacy of climate-related policy brought against foreign and domestic governments may accelerate the implementation of these measures. Given the evolving nature of climate change policy and the control of

GHG emissions and resulting requirements, including carbon taxes and carbon pricing schemes implemented by varying levels of government, it is expected that current and future climate change regulations will have the effect of increasing our operating expenses, and, in the long-term, potentially reducing the demand for oil, liquids, natural gas and related products, resulting in a decrease in our profitability and a reduction in the value of our assets.

Claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under certain laws or that such energy companies provided misleading disclosure to the public and investors of current or future risks associated with climate change. As a result, individuals, government authorities, or other organizations may make claims against oil and natural gas companies, including us, for alleged personal injury, property damage, or other potential liabilities. While we are not a party to any such litigation or proceedings, we could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely affect the demand for and price of securities issued by us, impact our operations and have an adverse impact on our financial condition.

Given the perceived elevated long-term risks associated with policy development, regulatory changes, public and private legal challenges, or other market developments related to climate change, there have also been efforts in recent years affecting the investment community, including investment advisors, sovereign wealth funds, banks, public pension funds, universities and other institutional investors, promoting direct engagement and dialogue with companies in their portfolios on climate change action (including exercising their voting rights on matters relating to climate change) and increased capital allocation to investments in low-carbon assets and businesses while decreasing the carbon intensity of their portfolios through, among other measures, divestments of companies with high exposure to GHG-intensive operations and products. Certain stakeholders have also pressured insurance providers and commercial and investment banks to reduce or stop financing, and providing insurance coverage to oil and natural gas and related infrastructure businesses and projects. The impact of such efforts require our management to dedicate significant time and resources to these climate change-related concerns, may adversely affect our operations, the demand for and price of our securities and may negatively impact our cost of capital and access to the capital markets.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social, governance and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators published for comment Proposed National Instrument 51-107 – *Disclosure of Climate Related Matters*, intended to introduce climate-related disclosure requirements for reporting issuers in Canada with limited exceptions. If we are not able to meet future sustainability reporting requirements of regulators or current and future expectations of investors, insurance providers, or other stakeholders, our business and ability to attract and retain skilled employees, obtain regulatory permits, licenses, registrations, approvals, and authorizations from various governmental authorities, and raise capital may be adversely affected. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Climate Change Regulation*".

Physical risks

Based on our current understanding, the potential physical risks resulting from climate change are long-term in nature and associated with a high degree of uncertainty regarding timing, scope, and severity of potential impacts. Many experts believe global climate change could increase extreme variability in weather patterns such as increased frequency of severe weather, rising mean temperature and sea levels, and long-term changes in precipitation patterns. Extreme hot and cold weather, heavy snowfall, heavy rainfall, and wildfires may restrict our ability to access our properties and cause operational difficulties, including damage to equipment and infrastructure. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of our assets are located in locations that are proximate to forests and rivers and a wildfire or flood may lead to significant downtime and/or damage to our assets or cause disruptions to the production and transport of our products or the delivery of goods and services in our supply chain.

Changing Investor Sentiment

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

Reputational Risk Associated with Our Operations

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

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

Non-Governmental Organizations

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

Alternatives to and Changing Demand for Petroleum Products

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy generation systems could reduce the demand for oil, natural gas and liquid hydrocarbons. Recently, certain jurisdictions have implemented policies or incentives to decrease the use of hydrocarbons and encourage the use of renewable fuel alternatives, which may lessen the demand for petroleum products and put downward pressure on commodity prices. Advancements in energy efficient products have a similar effect on the demand for oil and natural gas products. We cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on our business, financial condition, results of operations and cash from operating activities by decreasing our profitability, increasing our costs, limiting our access to capital and decreasing the value of our assets.

Political Uncertainty

Our results can be adversely impacted by political, legal, or regulatory developments in Canada and elsewhere that affect local operations and local and international markets. Changes in government, government policy or regulations, changes in law or interpretation of settled law, third-party opposition to industrial activity generally or projects specifically, and duration of regulatory reviews could impact our existing operations and planned projects. This includes actions by regulators or other political actors to delay or deny necessary licenses and permits for our activities or restrict the operation of third-party infrastructure that we rely on. Additionally, changes in environmental regulations, assessment processes or other laws, and increasing and expanding stakeholder consultation (including Indigenous stakeholders), may increase the cost of compliance or reduce or delay available business opportunities and adversely impact our results.

Other government and political factors that could adversely affect our financial results include increases in taxes or government royalty rates (including retroactive claims) and changes in trade policies and agreements. Further, the adoption of regulations mandating efficiency standards, and the use of alternative fuels or uncompetitive fuel components could affect our operations. Many governments are providing tax advantages and other subsidies to support alternative energy sources or are mandating the use of specific fuels or technologies. Governments and others are also promoting research into new technologies to reduce the cost and increase the scalability of alternative energy sources, and the success of these initiatives may decrease demand for our products.

A change in federal, provincial or municipal governments in Canada may have an impact on the directions taken by such governments on matters that may impact the oil and natural gas industry including the balance between economic development and environmental policy. The oil and natural gas industry has become an increasingly politically polarizing topic in Canada, which has resulted in a rise in civil disobedience surrounding oil and natural gas development—particularly with respect to infrastructure projects. Protests, blockades and demonstrations have the potential to delay and disrupt our activities. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*" and "*Industry Conditions – Transportation Constraints and Market Access*".

Indigenous Lands and Rights Claims

Opposition by Indigenous groups to the conduct our operations, development or exploratory activities in any of the jurisdictions in which we conduct business may negatively impact us in terms of public perception, diversion of management's time and resources, legal and other advisory expenses, and could adversely impact our progress and ability to explore and develop properties.

Some Indigenous groups have established or asserted Indigenous treaty, title and rights to portions of Canada. Although there are no Indigenous and treaty rights claims on lands where we operate, no certainty exists that any lands currently unaffected by claims brought by Indigenous groups will remain unaffected by future claims. Such claims, if successful, could have a material adverse impact on our operations or pace of growth.

The Canadian federal and provincial governments have a duty to consult with Indigenous people when contemplating actions that may adversely affect the asserted or proven Indigenous or treaty rights and, in certain circumstances, accommodate their concerns. The scope of the duty to consult by federal and provincial governments varies with the circumstances and is often the subject of ongoing litigation. The fulfillment of the duty to consult Indigenous people and any associated accommodations may adversely affect our ability to, or increase the timeline to, obtain or renew, permits, leases, licenses and other approvals, or to meet the terms and conditions of those approvals. For example, a recent British Columbia Supreme Court decision determined that the cumulative impacts of government sanctioned industrial development on the traditional territories of a First Nations group in northeast British Columbia breached that group's treaty rights. Going forward, this decision may have significant impacts on the regulation of industrial activities in northeast British Columbia. Further, it may lead to similar claims of cumulative effects across Canada in other areas covered by numbered treaties. The long-term impacts of and associated risks of the decision on the Canadian oil and natural gas industry and us remain uncertain.

In addition, the federal government has introduced legislation to implement the UNDRIP. Other Canadian jurisdictions, including British Columbia, have also introduced or passed similar legislation, or begun considering the principles and objectives of UNDRIP, or may do so in the future. The means and timelines associated with UNDRIP’s implementation by government is uncertain; additional processes may be created or legislation amended or introduced associated with project development and operations, further increasing uncertainty with respect to project regulatory approval timelines and requirements. See "*Industry Conditions – Indigenous Rights*".

Regulatory

The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for oil and natural gas and increase our costs, either of which may have a material adverse effect on our business, financial condition, results of operations and prospects. Further, the ongoing third party challenges to regulatory decisions or orders has reduced the efficiency of the regulatory regime, as the implementation of the decisions and orders has been delayed resulting in uncertainty and interruption to business of the oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

In order to conduct oil and natural gas operations, we require regulatory permits, licenses, registrations, approvals and authorizations from various governmental authorities at the municipal, provincial and federal level. There can be no assurance that we will be able to obtain all of the permits, licenses, registrations, approvals and authorizations that may be required to conduct operations that we may wish to undertake. In addition, certain federal legislation such as the *Competition Act* and the *Investment Canada Act* could negatively affect our business, financial condition and the market value of our Common Shares or our assets, particularly when undertaking, or attempting to undertake, acquisition or disposition activity. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management*".

Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. New environmental legislation at the federal and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation*".

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require us to incur costs to remedy such discharge. Although we believe that we are in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Royalty Regimes

There can be no assurance that the governments in the jurisdictions in which we have assets will not adopt new royalty regimes, or modify the existing royalty regimes, which may have an impact on the economics of our projects. An increase in royalties would reduce our earnings and could make future capital investments, or our operations, less economic. See "*Industry Conditions - Royalties and Incentives*".

Reliance on a Skilled Workforce and Key Personnel

Our operations and management require the recruitment and retention of a skilled workforce, including engineers, technical personnel and other professionals. The loss of key members of such workforce, or a substantial portion of the workforce as a whole, could result in the failure to implement our business plans which could have a material adverse effect on our business, financial condition, results of operations and prospects.

Competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that we will be able to continue to attract and retain all personnel necessary for the development and operation of our business. We do not have any key personnel insurance in effect. Contributions of the existing management team to our immediate and near-term operations are likely to be of central importance. In addition, certain of our current employees are senior and have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If we are unable to: (i) retain current employees; (ii) successfully complete effective knowledge transfers; and/or (iii) recruit new employees with the requisite knowledge and experience, we could be negatively impacted. In addition, we could experience increased costs to retain and recruit these professionals.

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.

Asset Concentration

Our producing properties are geographically concentrated. As a result, to the extent demand for and costs of personnel, equipment, power, services, and resources in such geographic area are high it could result in a delay or inability to secure the personnel, equipment, power, services, and resources. Any delay or inability to secure the personnel, equipment, power, services, and resources could result in crude oil, liquids and natural gas production volumes being below the our forecasted production volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our financial conditions, results of operations, cash flow, and profitability.

As a result of this concentration, we may be disproportionately exposed to the impact of delays or interruptions of operations or production in this area caused by external factors such as governmental regulation, provincial politics, market limitations, supply shortages, or extreme weather-related conditions.

Inflation and Cost Management

Our operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations. Our inability to manage costs may impact project returns and future development decisions, which could have a material adverse effect on our financial performance and cash from operating activities.

The cost or availability of oil and gas field equipment may adversely affect our ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to our operations for the expected price, on the expected timeline, or at all, may have an adverse effect on our financial performance and cash from operating activities.

Management of Growth

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

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 from operating activities, borrowings and possible future equity sales, our ability to do so is dependent on, among other factors:

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

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

Additional Funding Requirements

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

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

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, the payment of dividends, 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. 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.

We are required to meet government annual abandonment spending progress requirements, and to maintain a positive rating in all aspects of the AER LCA and liability assessment process, and we are restricted from completing asset dispositions and acquisitions that would result in our LCA ratings falling below such thresholds. We are also required to provide additional reporting to our lenders regarding our existing and/or budgeted abandonment and reclamation obligations, our decommissioning expenses, our LCA and/or any notices or orders received from an energy regulator in any applicable province. If there is a decline in our LCA below acceptable thresholds or if we become subject to an abandonment and reclamation order and our estimated cost of compliance with such order exceeds a certain threshold, we could be required to repay our credit facilities.

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

Issuance of Debt

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

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 2026 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 2026 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.

Prices, Markets and Marketing

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

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

Oil and natural gas prices may be volatile for a variety of reasons including market uncertainties over the supply and demand of these commodities due to the current state of the world economies, the ongoing COVID-19 pandemic, OPEC actions, political uncertainties, sanctions imposed on certain oil producing nations by other countries and conflicts in the Middle East. Prices for oil and natural gas are also subject to the availability of foreign markets and our ability to access such markets. A material decline in prices could result in a reduction of our net production revenue. The economics of producing from some wells may change because of lower prices, which could result in reduced production of oil or natural gas and a reduction in the volumes and the value of our reserves. We might also elect not to produce from certain wells at lower prices. Any substantial and extended decline in the price of oil and natural gas would have an adverse effect on the carrying value of our reserves, borrowing capacity, revenues, profitability and cash from operating activities and may have a material adverse effect on our business, financial condition, results of operations and prospects.

See "*Industry Conditions – Transportation Constraints and Market Access*".

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.

Market Price

The trading price of the securities of oil and natural gas issuers is subject to substantial volatility often based on factors related and unrelated to the financial performance or prospects of the issuers involved. Factors unrelated to our performance could include macroeconomic developments nationally, within North America or globally, domestic and global commodity prices, and/or current perceptions of the oil and natural gas market. In recent years, the volatility of commodities has increased due, in part, to the implementation of computerized trading and the decrease of discretionary commodity trading. In addition, the volatility, trading volume and share price of our Common Shares has been impacted by increasing investment levels in passive funds that track major indices, as such funds only purchase securities included in such indices. In addition, in certain jurisdictions, institutions, including government sponsored entities, have determined to decrease their ownership in oil and natural gas entities which may impact the liquidity of certain securities and may put downward pressure on the trading price of those securities. Similarly, the market price of our Common Shares could be subject to significant fluctuations in response to variations in our operating results, financial condition, liquidity and other internal factors. Accordingly, the price at which our Common Shares will trade cannot be accurately predicted.

Gathering and Processing Facilities, Pipeline Systems, Trucking and Rail

We deliver our products through gathering and processing facilities, pipeline systems and, in certain circumstances, by truck and 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, trucking and railway lines. Unexpected shutdowns 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.

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

Exploration, Development and Production Risks

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

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

Drilling hazards, environmental damage and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays in obtaining governmental approvals or consents, shut-ins of wells resulting from extreme weather conditions, insufficient storage or transportation capacity or geological and mechanical conditions. While diligent well supervision, effective maintenance operations and the development of enhanced oil recovery technologies can contribute to maximizing production rates over time, it is not possible to eliminate production delays and declines from normal field operating conditions, which can negatively affect revenue and cash from operating activities levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including, but not limited to, fire, explosion, blowouts, cratering, sour gas releases, spills and other environmental hazards. These typical risks and hazards could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment and cause personal injury or threaten wildlife. Particularly, we may explore for and produce sour gas in certain areas. An unintentional leak of sour gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to us.

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

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

Hydraulic Fracturing

Hydraulic fracturing involves the injection of water, sand, and small amounts of additives under high pressure into tight rock formations that were previously unproductive to stimulate the production of oil, liquids and natural gas. Concerns about seismic activity, including earthquakes, caused by hydraulic fracturing has resulted in regulatory authorities implementing additional protocols for areas that are prone to seismic activity or completely banning hydraulic fracturing in other areas. 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, liquids and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions or bans on hydraulic fracturing in the areas where we operate could result in us being unable to economically recover our oil and gas reserves and reserves, which would result in a significant decrease in the value of our assets.

Water is an essential component of our drilling and hydraulic fracturing processes. Limitations or restrictions on our ability to secure sufficient amounts of water (including limitations resulting from natural causes such as drought), could materially and adversely impact our operations. Severe drought conditions can result in local water authorities taking steps to restrict the use of water in their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, it may need to be obtained from new sources and transported to drilling sites, resulting in increased costs, which could have a material adverse effect on our financial condition, results of operations, and cash from operating activities.

In addition, we must dispose of the fluids produced from oil, liquids and natural gas production operations, including produced water, which we do directly or through the use of third-party vendors. The legal requirements related to the disposal of produced water into a non-producing geologic formation by means of underground injection wells are subject to change based on concerns of the public or governmental authorities regarding such disposal activities.

Another consequence of seismic events may be lawsuits alleging that disposal well operations have caused damage to neighboring properties or otherwise violated laws and regulations regarding waste disposal. These developments could result in additional regulation and restrictions on the use of injection wells by us or by commercial disposal well vendors that we may use from time to time to dispose of produced water. Increased regulation and attention given to induced seismicity could also lead to greater opposition, including litigation to limit or prohibit oil and natural gas activities utilizing injection wells for produced water disposal. Any one or more of these developments may result in us or our vendors having to limit disposal well volumes, disposal rates and pressures or locations, or require us or our vendors to shut down or curtail the injection of produced water into disposal wells, which events could have a material adverse effect on our business, financial condition, and results of operations.

See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – General – Alberta*".

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

We consider acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and our ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with our own. The integration of acquired businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided by third parties and the resources required to provide such services. In this regard, non-core assets may be periodically disposed of so we can focus our efforts and resources more efficiently. Depending on the market conditions for such non-core assets, certain of our non core assets may realize less on disposition than their carrying value on our consolidated 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 volatile commodity prices, many companies, including companies that may operate some of the assets in which we have an interest, may be in financial difficulty, which could impact their ability to fund and pursue capital expenditures, carry out their operations in a safe and effective manner and satisfy regulatory requirements with respect to abandonment and reclamation obligations. If companies that operate some of the assets in which we have an interest fail to satisfy regulatory requirements with respect to abandonment and reclamation obligations, we may be required to satisfy such obligations and to seek reimbursement from such companies. To the extent that any of such companies go bankrupt, become insolvent or make a proposal or institute any proceedings relating to bankruptcy or insolvency, it could result in such assets being shut-in, us potentially becoming subject to additional liabilities relating to such assets and us having difficulty collecting revenue due from such operators or recovering amounts owing to us from such operators for their share of abandonment and reclamation obligations. Any of these factors could have a material adverse affect on our financial and operational results. See "*Industry Conditions – Regulatory Authorities and Environmental Regulation – Liability Management*" and "*Third Party Credit Risk*" in these Risk Factors.

Project Risks

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

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

Reserves Estimates

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

- historical production from properties;
- production rates;
- ultimate reserve recovery;
- timing and amount of capital expenditures;
- marketability of oil and natural gas;
- royalty rates; and
- the assumed effects of regulation by governmental agencies and future operating costs (all of which may vary materially from actual results).

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

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

In accordance with applicable securities laws, our independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net revenues as summarized herein. Actual future net revenues will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and future net revenues 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 revenues 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.

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

Increasingly, social media is used as a vehicle to carry out cyber phishing attacks. Information posted on social media sites, for business or personal purposes, may be used by attackers to gain entry into our systems and obtain confidential information. Although we have a social media policy, we do not restrict the social media access of our employees. Despite these efforts, there are significant risks that the Corporation may not be able to properly regulate social media use and preserve adequate records of business activities and client communications conducted through the use of social media platforms.

We maintain policies and procedures that address and implement employee protocols with respect to electronic communications and electronic devices and conduct annual cyber-security risk assessments and our leadership team briefs our Board at least once per year on information security matters. We apply technical and process controls in line with industry accepted standards to protect our information, assets and systems, including a written incident response plan for responding to a cyber-security incident. Our information technology department routinely advises us of any material security issues and ensures any training required is carried out in a prudent, timely manner. We also have a standardized on-boarding process for new employees which provides training on our information technology security protocols. In addition on an annual basis, all of our employees, including our executives and Board members certify that they have read and fully understand our information technology policies. We also have information technology policies applicable to employees who are working remotely and we employ encryption protection of our confidential information, all computers and other electronic devices.

We have not experienced a security breach in the last three years that had a material impact on our business. Nevertheless, despite our efforts to mitigate such cyber phishing attacks through education and training, cyber phishing activities remain a serious problem that may damage our information technology infrastructure. We apply technical and process controls in line with industry-accepted standards to protect our information, assets and systems, including a written incident response plan for responding to a cyber-security incident. However, these controls may not adequately prevent cyber-security breaches. Disruption of critical information technology services, or breaches of information security, could have a negative effect on our performance and earnings, as well as our reputation, and any damages sustained may not be adequately covered by our current insurance coverage, or at all. The significance of any such event is difficult to quantify, but may in certain circumstances be material and could have a material adverse effect on our business, financial condition and results of operations.

Cost of New Technologies

The petroleum industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other companies may have greater financial, technical and personnel resources that allow them to implement and benefit from technological advantages. There can be no assurance that we will be able to respond to such competitive pressures and implement such technologies on a timely basis, or at an acceptable cost. If we do implement such technologies, there is no assurance that we will do so successfully. One or more of the technologies currently utilized by us or implemented in the future may become obsolete. 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.

Variations in Foreign Exchange Rates and Interest Rates

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

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

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

Hedging

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

- production falls short of the hedged volumes or prices fall significantly lower than projected;
- there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement;
- counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; or

- a sudden unexpected event materially impacts oil and natural gas prices.

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

Title to and Right to Produce from Assets

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

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

Insurance

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

Our insurance policies are generally renewed on an annual basis and, depending on factors such as market conditions, the premiums, policy limits and/or deductibles for certain insurance policies can vary substantially. In some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Significantly increased costs could lead us to decide to reduce or possibly eliminate, coverage. In addition, insurance is purchased from a number of third-party insurers, often in layered insurance arrangements, some of whom may discontinue providing insurance coverage for their own policy or strategic reasons. Should any of these insurers refuse to continue to provide insurance coverage, our overall risk exposure could be increased and we could incur significant costs.

Dilution

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

Expiration of Licenses and Leases

Our properties are held in the form of licences and leases and working interests in licences and leases. If we, or the holder of the licence or lease, fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of our licences or leases or the working interests relating to a licence or lease and the associated abandonment and reclamation obligations may have a material adverse effect on our business, financial condition, results of operations and prospects.

Litigation

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

Intellectual Property Litigation

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

Breach of Confidentiality

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

Russian Ukrainian Conflict

In February 2022, Russian military forces invaded Ukraine. In response, Ukrainian military personnel and civilians are actively resisting the invasion. Many countries throughout the world have provided aid to the Ukraine in the form of financial aid and in some cases military equipment and weapons to assist in their resistance to the Russian invasion. The North Atlantic Treaty Organization ("**NATO**") has also mobilized forces to NATO member countries that are close to the conflict as deterrence to further Russian aggression in the region. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the peace and stability of the region and the world economy.

In addition, certain countries including Canada and the United States, have imposed strict financial and trade sanctions against Russia, which sanctions may have far reaching effects on the global economy. As part of the sanctions package, the German government paused the certification process for the 1,200 km Nord Stream 2 natural gas pipeline that was built to carry natural gas from Russia to Germany. Russia is a major exporter of oil and natural gas. Disruption of supplies of oil and natural gas from Russia could cause a significant worldwide supply shortage of oil and natural gas and have a significant impact on worldwide prices of oil and natural gas. A lack of supply and high prices of oil and natural gas could have a significant adverse impact on the world economy. The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain.

Income Taxes

We file all required income tax returns and believe that we are in full compliance with the provisions of the Tax Act 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.

Third Party Credit Risk

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

Conflicts of Interest

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

Firm Commitment Transportation and Processing Arrangements

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

Expansion into New Activities

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

Dividends

We do not currently pay dividends on our outstanding Common Shares. Payment of dividends in the future will be dependent on, among other things, our results of operations, financial condition, the need for funds to finance ongoing operations and other considerations, as the Board considers relevant.

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 "*Notice to Reader – Special Note Regarding Forward-Looking Statements*" of this Annual Information Form.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Legal Proceedings

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

We filed a Statement of Defence on February 7, 2019 at DTFN's request. Our Statement of Defence describes our operations and maintenance of the Sousa NW Alberta pipeline, our immediate actions taken upon discovering the pipeline spill, efforts to completely remediate the spill site at a cost to us of approximately $13 million, and denials of liability. DTFN filed a Reply to Defence on November 21, 2019. Affidavits of Records have not been served.

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

An application was brought in December to have the individual defendants struck from Trident's claim. The application was partially successful as it led Trident to drop its claims against three of our employees. All the defendants have filed their Statements of Defence and we and Trident have produced their Affidavits of Records.

We have filed a security for costs application, which was successful. The Defendants, including NuVista, have now applied to have the claim summarily dismissed. A hearing on the dismissal has not yet been scheduled.

Regulatory Actions

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

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

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

AUDITORS

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

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for our Common Shares is Odyssey Trust Company at its principal offices in Calgary, Alberta and in Toronto, Ontario. The transfer agent for our 2026 Notes is Computershare Trust Company of Canada.

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 2026 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 Vice Chair and former 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 10, 2022. Additional financial information is contained in our financial statements for the year ended December 31, 2021 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 Ltd.
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, 2021, 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 Chair of the Reserves Committee

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

(signed) "*Pentti O. Karkkainen*"
Pentti O. Karkkainen
Chair

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

March 7, 2022

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, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2021, 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, 2021, 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 Ltd.	Dec. 31, 2021	Canada	—	4,356,606	—	**4,356,606**

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 Ltd., Calgary, Alberta, Canada, February 28, 2022.

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

APPENDIX C

NUVISTA ENERGY LTD.
MANDATE OF THE AUDIT COMMITTEE

Role and Objective

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

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

Membership of Committee

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

Meetings

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

- The Committee shall forthwith report the results of meetings and reviews undertaken and any associated recommendations to the Board of Directors.

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

Mandate and Responsibilities of Committee

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

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

    - identifying, monitoring and mitigating business risks; and

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

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

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

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

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

    - ascertaining compliance with covenants under loan agreements;

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

    - reviewing disclosure requirements for commitments and contingencies;

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

    - reviewing unresolved differences between management and the external auditors;

    - reviewing non-recurring transactions;

    - reviewing related party transactions; and

    - obtaining explanations of significant variances with comparative reporting periods.

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

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

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

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

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

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

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

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

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

- The Committee shall establish a procedure for:

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

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

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

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

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

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

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

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

- enquiring as to any differences between management and the external auditor;
- enquiring as to material differences in accounting policies, disclosures or presentation from prior periods;
- enquiring as to deficiencies in internal controls identified in the course of the performance of the procedures by the Chief Financial Officer; and
- enquiring as to any other matters or observations that the external auditors would like to bring to the attention of the Committee.

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

Reviewed and re-approved by the Board of Directors: March 7, 2022.

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