kiwetinohk® energy

Annual Information Form

For the year ended December 31, 2020

November 23, 2021

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APPENDICES

PRESENTATION OF INFORMATION AND EXCHANGE RATE INFORMATION

Presentation of Information

Throughout this annual information form (this "**Annual Information Form**" or "**AIF**"), the terms "Kiwetinohk" and the "Company" refer to Kiwetinohk Energy Corp.

Appendix "A" to this Annual Information Form, titled "Glossary, Selected Abbreviations and Selected Conversions", contains definitions for terms and abbreviations that are used in this AIF but are not defined elsewhere herein. Certain other terms used in this AIF that are 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 or CSA 51-324, as applicable. Appendix "A" also provides information about conversions between Standard Imperial Units and the International System of Units (or metric units) and between units of measurement that are utilized in this AIF.

On September 22, 2021, in connection with the completion of the Business Combination, the Company completed the Consolidation. Unless otherwise specified, all references to Common Shares, the issuance of Common Shares or the exercise or conversion price of any securities to acquire Common Shares in this AIF are presented on a post-Consolidation basis. In order to appropriately reflect the Consolidation, Common Shares issuable pursuant to existing grants of Options and Performance Warrants were divided by 10, and the corresponding exercise prices of those Options and Performance Warrants were multiplied by 10.

The Company's integrated energy transition business is in its early stage of development and the Company has no history of operating such business. Furthermore, none of the Company's power generation and hydrogen production projects have a final design, performance projection or cost estimate, or full regulatory approval or internal or external funding. Successful execution of the Company's energy transition strategy requires access to additional capital and other resources, such as development and availability of technological advances and a favourable regulatory regime, among others, which may be outside of the Company's control. While the Company believes in its strategy for building a differentiated energy transition company and considers its short, medium and long-term aspirations set forth in this AIF to have reasonable basis, there is no assurance that the Company will be able to successfully execute on such strategy in the manner or within the timeframe currently anticipated. See "*Risk Factors*" for further information.

Unless otherwise noted, the information contained in this AIF is given at the date of this AIF.

Words importing the singular number include the plural and vice versa, and words importing any gender include all genders.

Unless otherwise indicated, all references to "$" or "dollars" refer to Canadian dollars and all references to "US$" or "U.S. dollars" refer to United States dollars.

Figures, columns and rows presented in tables provided in this AIF may not add due to rounding.

Except as otherwise specified herein, the financial information in this AIF has been presented in accordance with IFRS.

Exchange Rate Information

The following table lists, for each period presented, the high and low exchange rates, the average exchange rate in effect during the period indicated and the exchange rates at the end of the period for one Canadian dollar, expressed in U.S. dollars, based on the indicative exchange rate posted by the Bank of Canada:

			Year ended December 31		
	Three Months Ended September 30, 2021	**Nine Months Ended September 30, 2021**	**2020**	**2019**	**2018**
High for the period	$ 0.8102	$ 0.8306	$ 0.7863	$ 0.7699	$ 0.8138
Low for the period	$ 0.7778	$ 0.7778	$ 0.6898	$ 0.7353	$ 0.7330
End of the period	$ 0.7849	$ 0.7849	$ 0.7854	$ 0.7699	$ 0.7330
Average for the period(1)	$ 0.7937	$ 0.7994	$ 0.7461	$ 0.7537	$ 0.7721

Note:
(1) Calculated as an average of the daily Bank of Canada Noon Rates for each day during the respective period.

The exchange rate for one Canadian dollar, expressed in U.S. dollars on November 23, 2021, based on the noon spot exchange rate of the Bank of Canada, was $1.00 = US$0.7870.

FORWARD-LOOKING STATEMENTS AND MARKET DATA

Certain statements contained in this AIF constitute "forward-looking statements" or "forward-looking information" within the meaning of Applicable Securities Laws (collectively, "**forward-looking statements**"). These statements relate to management's or, as noted, an independent evaluator's expectations about future events, results of operations and the Company's future performance (both operational and financial) and business prospects. All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "contemplate", "continue", "estimate", "expect", "intend", "propose", "might", "may", "will", "shall", "project", "should", "could", "would", "believe", "predict", "forecast", "pursue", "potential", "objective" and "capable" and similar expressions are intended to identify forward-looking statements. 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. No assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this AIF should not be unduly relied upon. Unless otherwise indicated, these statements speak only as of the date of this AIF. In addition, this AIF may contain forward-looking statements and forward-looking information attributed to third-party industry sources.

In particular, this AIF contains forward-looking statements pertaining to the following:

- the Company's objectives, strategies and competitive strengths and weaknesses;
- the Company's growth strategy, including its focus on consolidation of strategic upstream assets, identification and development of natural gas-fired power generation and renewable projects and the Company's plans for integration of its upstream and power portfolios;
- the Company's plans for developing a low emission power generation business as a source of power for Alberta's electrical grid (including contributing to the reliability of the grid), including development of its natural gas-fired and solar and wind power generation projects and expectations with respect to future opportunities for other renewable energy projects;

- the Company's ability to achieve its short-, medium- and long-term goals, including the Company's ability to: bring its natural gas production into equivalent proportion with its use of natural gas for hydrogen and electricity production; produce and supply desired volumes of power, natural gas and hydrogen; and capture and utilize more than 90% of the carbon dioxide ("**CO_2**") associated with Scope 1 emissions;

- expectations regarding the further development and operation of the Company's existing upstream properties, including the Company's ability to add production, reserves and net present value and the Company's plans for exploration, resource testing, development, exploitation and acquisitions;

- future commodity prices;

- projections of market prices and costs;

- nature, timing and development of the Company's capital projects, including the expected financial performance thereof following completion of the development and the commencement of operations, as applicable;

- estimates of EBITDA and underlying assumptions;

- the quantity and quality of the Company's inventory of drilling locations and the Company's plans with respect to development and operation of its upstream properties, including estimates of drilling and completion costs and efficiency improvements;

- the estimated quantity and value of the Company's reserves and the reserves potential and expected production profile of the Company's upstream assets, including decline rates and internal rates of return;

- expectations with respect to the Company's financial position and future funds from operations, cash flows, net earnings and other financial results;

- the Company's current capital budget, capital investment programs and future capital requirements for both its upstream and power generation and renewable power portfolio, including its ability to raise capital;

- expectations regarding contractual obligations and commitments, benefits therefrom and their expected timing of funding;

- the Company's beliefs and expectations with respect to its business model, energy demands, energy transition, the future of energy, distribution of power prices, and the best strategies for Kiwetinohk to succeed in the Alberta power industry moving forward;

- expectations regarding water use regulations and requirements in light of climate change, community and industrial growth;

- the Company's ability to achieve its near to medium term objectives, including but not limited to: building power generation projects that capture solar and wind renewable energy and an array of natural gas-fired power generation projects that include carbon capture, utilization and storage ("**CCUS**"); adapting, extending and applying existing CCUS technologies with *Firm Renewable* plants and NGCC plants; storing CO_2 in underground storage reservoirs; and certain other short- to mid-term goals (as further described under the heading "*Kiwetinohk's Aspirations and the Energy Transition Business Environment are Aligned – Near to Medium Term Objectives*");

- the Company's ability to achieve its mid- to long-term objectives, including but not limited to: combining hydrogen production from natural gas with power generation; bringing natural gas production into equivalent proportion with its use of natural gas for electricity and hydrogen production; providing low/zero carbon energy in the form of electricity and hydrogen; building *Firm Renewable* gas-fired plants; becoming a significant supplier of power to the Alberta power grid; and certain long-term aspirational goals (as further described under the heading "*Kiwetinohk's Aspirations and the Energy Transition Business Environment are Aligned – Mid- to Long-Term Objectives*");

- future costs, including abandonment and reclamation cost expectations;

- access to third-party infrastructure and the expected limitations, costs and benefits thereof;

- existing and proposed transportation and processing infrastructure and the contracts relating thereto and the expected benefits thereof;

- the use of risk-management techniques, including hedging;

- the Company's estimates of future interest and foreign exchange rates;

- the Company's dividend policy, should one be adopted, including the sustainability of dividend payments and the amount, timing and taxation of dividend payments;

- expectations that the Company's competitive advantages will yield successful execution of its business strategy and the degree of any such success achieved;

- the Company's ability to capitalize on certain energy transition opportunities through the use of new, innovative technologies in the market;

- industry conditions pertaining to the crude oil and natural gas industry and the energy transition and renewable power industries;

- the Company's treatment under governmental regulatory regimes and tax laws, including estimated tax pools and the Company's tax horizon;

- the Company's consultation with government and other stakeholders in respect of regulatory developments and other matters;

- the Company's management team as it evolves, including the continuity of employment of any person;

- anticipated growth in the market share for gas fired power generation and renewable power generation in Alberta;

- the compensation arrangements and economic interest of the Company's management team in the Company's equity and the benefits thereof; and

- the Company's future general and administrative expenses.

With respect to forward-looking statements contained in this AIF, assumptions have been made regarding, among other things:

- future oil, NGL and natural gas prices;

- the Company's ability to realize on expectations regarding low supply cost, reliability and efficiency of its power generation portfolio;

- development and completion of the Company's natural gas-fired and solar power generation projects in a timely and cost-efficient manner and the Company's ability to continue to identify and progress projects for its power generation portfolio;

- the Company's ability to successfully integrate its upstream business and assets with the Company's power generation portfolio;

- the Company's ability to obtain qualified staff and equipment in a timely and cost-efficient manner;

- the regulatory framework governing royalties, electricity generation, transmission and distribution, taxes and environmental matters in the jurisdictions in which the Company conducts its business and any other jurisdictions in which the Company may conduct its business in the future;

- the Company's ability to market production of oil, condensate, NGL, natural gas, electricity, low-emissions electricity, hydrogen, CO_2 and tax credits and other financial instruments as they emerge and evolve from time to time related to the production of low-emissions electricity and/or hydrogen successfully to customers;

- the Company's ability to buy and sell hydrocarbon gathering and processing services and CCUS services to other parties;

- the Company's future production levels;

- the applicability of technologies for recovery and production of the Company's reserves and the production of electricity and/or hydrogen and the implementation of emissions reducing technologies including but not limited to CCUS in connection with its power generation business;

- the recoverability of the Company's reserves;

- that the Company will have access to solar and other renewable resources in amounts and at the costs consistent with the amounts and costs expected by the Company for the development projects in its power generation portfolio;

- the nature of carbon capture technologies and the benefits of their application, including to the Company's proposed projects;

- future cash flows from production;

- future sources of funding for the Company's capital program and the Company's plans for future capital investments;

- the Company's future debt levels;

- geological and engineering estimates in respect of the Company's reserves;

- the geography of the areas in which the Company is conducting exploration and development activities, including for its natural gas-fired and solar power generation projects and peaker power plant, and the access, economic, regulatory and physical limitations to which the Company may be subject from time to time;

- community and stakeholder commitment to sustainable energy sources, and the Company's positioning within the sustainable energy or energy transition space;
- the intentions of the board of directors of the Company ("**Board**") with respect to the executive compensation plans and corporate governance programs described herein;
- the impact of competition on the Company;
- the Company's ability to obtain the support of stakeholders other than regulators which may affect the Company's ability to efficiently develop its capital projects including the cost or timing thereof; and
- the Company's ability to obtain financing necessary for the advancement of the Company's business plan on acceptable terms.

Actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and included elsewhere in this AIF, including:

- risks associated with developing and operating the power generation and renewable energy business;
- the ability of the Company to achieve its investment and development objectives;
- the ability of the Company to successfully execute its energy transition strategy;
- the successful integration of Distinction and KRC into one cohesive entity, being the Company;
- risks associated with exploration, development and production of crude oil and natural gas, and drilling for unconventional oil, NGL and natural gas;
- the risks and limitations of forecasting reserves data;
- risks associated with operating and integrating a newly-combined business;
- global economic and financial conditions;
- capital markets;
- licences and permits;
- government regulations;
- health, safety and environmental risks;
- competition in the crude oil and natural gas industry;
- carbon taxes and environmental compliance costs;
- coronavirus ("**COVID-19**");
- market constraints and access to services and equipment;
- talent, recruitment and retention of key personnel;
- technology risks;

- seasonality;
- environmental, health and safety requirements; and
- the other factors discussed under "Risk Factors".

Readers are cautioned that the foregoing list of risk factors should not be construed as exhaustive.

In addition, information and statements in this AIF relating to reserves are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated, and that the reserves described can be profitably produced in the future. See "*Presentation of Oil and Gas Reserves and Production Information*".

Forward-looking financial information contained in this AIF is based on assumptions about future events, including economic conditions and proposed courses of action, based on management's assessment of the relevant information currently available. In particular, this AIF contains estimates of the total installed cost for certain of the Company's renewable power generation projects. These estimates constitute forward-looking statements and are based on a number of material assumptions and factors set out above and are provided to give the reader a better understanding of the potential future performance of the Company. Actual results may differ significantly from the estimates presented herein. These estimates may also be considered to contain future oriented financial information. The actual results of the Company's operations for any period will likely vary from the amounts set forth in these estimates, and such variations may be material. See above and under the heading "*Risk Factors*" for a discussion of the risks that could cause actual results to vary. The future oriented financial information contained in this AIF has been approved by management as of the date of this AIF. Readers are cautioned that any future-oriented financial information contained herein should not be used for purposes other than those for which it is disclosed herein.

The prospective financial information included in this AIF has been prepared by, and is the responsibility of, the Company's management. The Company's management believe that the prospective financial information has been prepared on a reasonable basis, reflecting management's best estimates and judgments, and represents, to the best of management's knowledge and opinion upon review by the Company's Board of Directors, the Company's expected course of action. However, because this information is highly subjective, it should not be relied on as necessarily indicative of future results.

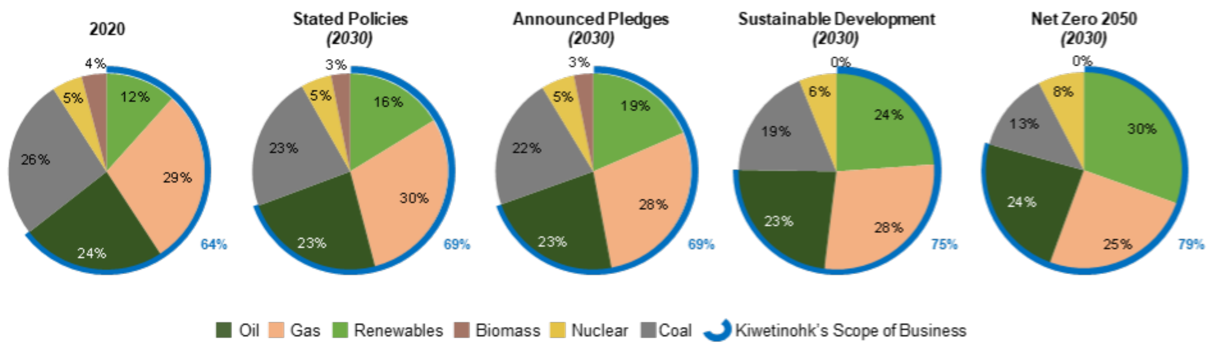
The forward-looking statements included in this AIF are expressly qualified by this cautionary statement and, except as otherwise indicated, are made as of the date of this AIF. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, management cannot assure that actual results will be consistent with these forward-looking statements. Investors should not place undue reliance on forward-looking statements. The Company does not undertake any obligation to publicly update or revise any forward-looking statements or departures from them except as required by Applicable Securities Laws.

This AIF includes market share, industry and other statistical information obtained from independent industry publications, government publications, market research reports and other published independent sources. Such publications and reports generally state that the information contained therein has been obtained from sources believed to be reliable. Although Kiwetinohk believes these publications and reports to be reliable, it has not independently verified any of the data or other statistical information contained therein, nor has it ascertained or validated the underlying economic or other assumptions relied upon by these sources. Kiwetinohk has no intention and undertakes no obligation to update or revise any such information or data, whether as a result of new information, future events or otherwise, except as required by Applicable Securities Laws.

KIWETINOHK'S ASPIRATIONS AND THE ENERGY TRANSITION BUSINESS ENVIRONMENT ARE ALIGNED

Evolution of Primary Energy Demand and Kiwetinohk's Scope of Business

Under each of its four long-term forecast scenarios, the International Energy Agency (the "**IEA**") projects global primary energy demand to undergo a fundamental shift to cleaner, less greenhouse gas ("**GHG**") intensive energy. By 2030, based on the IEA's future projections, use of traditional carbon-intensive fuels such as coal is expected to moderate substantially, largely offset by an expected increase in renewable power generation. While renewable energy is expected to account for a larger share of total energy demand, so too is natural gas-fired power generation in absolute terms, which is expected to backstop intermittent renewable power generation and moderate costly power price spikes and power failures, while still advancing global GHG reductions. Under the IEA's *Net Zero Emissions by 2050* case, oil, natural gas, and renewables are expected to account for a combined 79% of total primary energy demand by 2030[1].



The IEA projections are consistent with Kiwetinohk's view that energy solutions must address four needs: reliability, adequacy, clean energy (low emissions) and profitability. As the IEA projections indicate and recent global energy shortages demonstrate[2], complete exclusion of hydrocarbons, especially natural gas, is not practical, reliable or affordable with current commercial renewable technologies.

Kiwetinohk acknowledges that fossil fuels are required for a transition period until new technologies can meet the four needs without hydrocarbons. The Company believes that use of natural gas, the cleanest fossil fuel (in terms of energy released per unit of CO_2 emitted), together with CCUS, offers a fast, sensible path to measurable global emissions reduction. Furthermore, the Company believes that relying heavily on future technology improvements to address the climate change challenge is impractical given the lack of immediate alternatives to natural gas or coal to meet a system's firm power requirements.

Advances in battery technology and renewable supply capacity are likely required to eliminate the need for natural gas and other petroleum products. Current batteries for either portable use, such as long-distance transportation, and stationary uses, such as stabilizing volatile wind and solar power supply, do not meet reasonable performance specifications for widespread adoption. Kiwetinohk believes that the supply side of Alberta energy market's best response to the climate change challenge is to:

1. build solar and wind renewable power,

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[1] "World Energy Outlook 2021" (October 2021), online (pdf): *IEA* <https://www.iea.org/reports/world-energy-outlook-2021>.

[2] "Global energy crisis: how key countries are responding" (12 October 2021), online: *The Guardian* <https://www.theguardian.com/business/2021/oct/12/global-energy-crisis-how-key-countries-are-responding>.

2. advance the development of hydrogen distribution and use infrastructure,

3. stabilize and back-up intermittent renewable capacity with natural gas-fired power generation with CCUS, and

4. monitor battery technology and other technology to support the energy transition.

The Company is presently positioning itself to participate in all four of these areas.

To Kiwetinohk, the energy transition involves transforming today's energy systems to create reliable and affordable electricity to meet consumer electricity demand with low, and ultimately potentially net zero, GHG emissions. However, based on Kiwetinohk's internal projections for the buildout of its natural gas-fired power with CCUS and renewable power portfolio, net zero emissions cannot be achieved without external offsets. Therefore, Kiwetinohk approaches these business goals with a sense of urgency because:

1. Certain GHGs such as CO_2 have a long-life expectancy in the earth's atmosphere. What is emitted in the next few years will accumulate in the atmosphere and will continue to persist in the long term. Technology is evolving at a rapid pace and governments are devising policies that may make the net zero goal by 2050 possible and economic. For now, great strides can be profitably achieved with current technology and current legislation.

2. Regulations are constantly evolving, leading to opportunities that are unlikely to last a long time. Examples include but are not limited to:

   a. mandated phase out of coal-fired power generation is creating a market demand for low-carbon energy to replace coal and to accommodate electrical power demand growth opening the door to grid capacity for new renewable and gas-fired power generation,

   b. the Government of Alberta is seeking industry input before finalizing new policy regarding injection of CO_2 for permanent disposal into saline aquifers, creating an opportunity to secure the right to sequester CO_2 captured at any future gas-fired power project that the Company may build, and

   c. the Government of Canada is considering subsidies for CCUS which may create opportunities for superior overall economics that include the capture of CO_2 in the Company's proposed gas-fired power projects.

For these reasons, the Company believes the time to act on emissions reductions is now, using immediate best-efforts at reducing carbon emissions alongside advancing zero-emission technology. The Company believes that an energy transition with private capital and companies doing as much as can profitably be done, as fast as it can be done, with awareness of zero-emissions technology development, but without waiting on full zero emissions technology and systems, is important and necessary.

The global shift to clean energy is creating opportunities based on favorable government policies. These policies are aimed at sustainability, energy security and emissions reduction. For private capital investment to be motivated to meet the challenges of climate change, Kiwetinohk believes that sustainability requires profitability and profitability requires sustainability. Kiwetinohk aims to compete on the basis of both economics and emissions with Alberta's power producers and other energy suppliers to provide reliable energy products in an increasingly electrified and, potentially, hydrogen-fueled world.

To execute on its energy transition strategy, Kiwetinohk must excel in producing both natural gas and converting primary energy sources including solar, wind and natural gas to clean energy vectors, such as electricity and hydrogen. The Company's present aspiration is to maintain production of natural gas and use of natural gas for low-carbon energy production in near balance.

Burning natural gas generally produces more usable heat per unit of CO_2 emitted than burning other fossil fuels. Further, producing, shipping and burning pipeline specification natural gas is often more energy efficient than the use of liquid, such as crude oil, and solid fuels, such as coal. For those reasons, the Company believes that simply converting from coal and crude oil to natural gas is a logical first step forward in the energy transition.

Preparing for an Orderly Energy Transition

Lessons learned from other jurisdictions navigating the energy transition provide insight into the potential risks and opportunities for Alberta, which is expected to be the Company's principal market. Future reliability, relative cost and price volatility of energy supply are all important measures when evaluating the effectiveness of approaches to energy transition.

Kiwetinohk believes valuable insight can be gained from analyzing the energy transition in Europe. Significant investment in renewable power occurred without a supporting increase in fast-responding, clean-burning, natural gas-fired backstop power resulting in energy shortages during intermittent low-output periods of renewable power supply. Due to lack of natural gas investment and infrastructure, this led to a reversion to coal and diesel power generation to fill these gaps. Furthermore, the misunderstanding of the importance of natural gas as a stabilizing fuel source for the energy transition drove a lack of natural gas investment which has created current significant gas price inflation and resulted in major energy and service businesses seeking government bailouts to fund this hyperinflation[3].

Kiwetinohk believes that natural gas power generation is a necessary element of an energy transition away from traditional, carbon intensive methods of power generation. As recent global energy shortages demonstrate, the failure to appreciate the role of natural gas in an orderly energy transition may result in power shortages, steep increases in power pricing and, potentially, a reversion to less clean energy sources such as coal.

Kiwetinohk's Business Strategy in Response to the Climate Change Challenge

Kiwetinohk was conceived, and its mandate remains, to build an energy transition company, one that responds to the global challenge presented by climate change but specifically adapted to the situation in Alberta's energy markets. Kiwetinohk's long-term aspiration is to be a leading producer of low-carbon energy into the Alberta power and hydrogen markets. The Company is currently at an early stage and this AIF describes the Company's current activities, short to mid-term plans and mid to long-term aspirations in the context of rapidly evolving technology and regulations.

Kiwetinohk's vertically integrated business model is premised on pairing natural gas production with natural gas-fired and renewable power generation. The Company believes this business model will position the Company advantageously to meet increasing demand for electricity in the context of a shifting energy landscape. The Company expects that neither renewables nor gas-fired power, alone, can provide an adequate solution for stable low-emissions grid power supply. The Company plans to pursue a business model that it expects will result in superior returns to its investors and allow them to participate in the growth of a balance of low carbon and zero carbon energy sources.

In 2021, the Company completed acquisitions of attractive upstream oil and gas assets and associated infrastructure. These assets consist of high-netback, liquids-rich natural gas production with development upside and substantial spare natural gas processing capacity from owned infrastructure (see "*Description*

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[3] "U.K. Energy Firms Seek Bailout as Government Talks Run On" (19 September 2021), online: *BNN Bloomberg* < https://www.bnnbloomberg.ca/u-k-energy-firms-seek-bailout-as-government-talks-run-on-1.1654413>; "Pollution Cost Surges to Record 65 Euros as Europe Burns Coal" (27 September 2021), online: *BNN Bloomberg* <https://www.bnnbloomberg.ca/pollution-cost-surges-to-record-65-euros-as-europe-burns-coal-1.1657974>.

of Kiwetinohk's Business – Upstream Properties Description" herein). The upstream assets also provide a foundational base for the Company to pursue energy transition opportunities.

Kiwetinohk's Current Activities in the Context of the Global Challenge to Provide Renewable Energy and Reduce GHG Emissions

The tables below describes certain types of low-carbon energy projects and their present status within the Company:

Type of Project	Present Status Within Kiwetinohk
Natural gas resource development and production	Base of high-quality properties has been acquired. Please see "*Description of Kiwetinohk's Business – Upstream Business Description*". Monitoring market for opportunities.
Solar photovoltaic power generation	Option to lease land has been secured for one project and application has been advanced in the Alberta Electrical System Operator ("**AESO**") approval process[4] to Stage 2. Continuing to search for land suited to solar power development for additional projects.
Natural gas-fired power generation (*Firm Renewable** configuration) *The term "*Firm Renewable*" is a Kiwetinohk-originated term that describes efficient, flexible-output, fast-responding, gas-fired, internal reciprocating engine-driven power generation that addresses the need for stability that has been revealed as wind and solar renewable grows to become a significant proportion of a grid's power supply. See also the section entitled, "Near to Medium Term Objectives".	Front end engineering and design ("**FEED**") is underway for a 101 MW, fast-responding, flexible-output, internal reciprocating engine-driven power generation (which Kiwetinohk calls *Firm Renewable*) project. The project has been advanced to AESO Stage 1. Pre-FEED evaluation and investigation is underway for the addition of a pilot scale – 1/9 total capacity – carbon capture project to be added onto this project).
Natural gas-fired power generation (natural gas combined cycle configuration)	Identification and acquisition of locations with favorable attributes for the location of natural gas combined cycle ("**NGCC**") power plants is underway. Two projects are in the AESO approval process, with both at AESO Stage 1.
Hydrogen production	The Company is evaluating a joint venture which, if implemented, is expected to supply hydrogen production from gas, hydrogen-fired simple cyclic turbine-power generator and hydrogen-fueled process heat to an industrial complex.
Wind turbine power generation	The Company is evaluating locations for greenfield projects as well as projects currently in the approval process.
CCUS	The Company aspires to add CCUS to its expected gas-fired power generation, as technology and economics

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[4] "Connection Process", online: *aeso* <https://www.aeso.ca/grid/connecting-to-the-grid/connection-process/>.

	allow, and will test each gas-fired plant on a case-by-case basis. The Company is presently evaluating adding a CCUS pilot to a *Firm Renewable* project. If advanced to completion the project, as currently conceived, will evaluate a new CO_2 solvent that the Company believes may have superior properties to commercially proven solvents. The Company has screened most of the known crude oil pools in south, central and northwest Alberta to establish a preliminary estimate of suitability for carbon dioxide enhanced oil recovery ("**CO_2 EOR**") for each. Pursuant to an investigation now underway by the Government of Alberta, the Company has also filed an expression of interest to acquire rights to inject CO_2 into brine aquifers in three regions of Alberta.

In addition to the projects listed above, the Company also monitors the evolution of new technology and markets which can advance the transition of energy toward lower cost and / or lower GHG emissions supply. These technologies and markets include but are not limited to:

1. Advancements in large capacity power storage that can provide an alternative to *Firm Renewable* in managing the volatility of the gap between intermittent solar and wind renewable supply and demand on the electricity grid,

2. Advancements in geothermal technology including heat-to-power systems that can make geothermal (in the conditions that prevail in Alberta) comparable in cost and full-scope emissions to other sources of energy for power generation,

3. Advancements in hydrogen storage and distribution systems (both technology and installed capacity) that enable new markets for hydrogen,

4. Advancements in oxygen and gas fired (oxy-fuel) power systems that can eliminate the need for much of the carbon capture component of CCUS systems, and

5. Carbon capture systems that increase the CO_2 capture efficiency and /or reduce the toxicity and corrosivity and improve the regeneration energy efficiency relative to commercially established systems.

In these times of rapid technology evolution, Kiwetinohk sees technical development as both an opportunity and a threat. The Company looks at its transition investments with a view to managing risk of obsolescence or non-competitive performance due to eventual commercialization of competing technology evolution.

Near to Medium Term Objectives

Kiwetinohk's short- to mid-term goal is to build power generation projects that capture solar and wind renewable energy and to build an array of natural gas-fired power generation projects that include CCUS supporting these projects. The Company aspires to produce sufficient natural gas to meet its own needs. While the Company intends to maintain expertise to enhance oil recovery with CO_2 EOR, it is prepared to acquire suitable oil resources and (as a matter of preference not necessity) to work with other companies that hold and operate suitable assets if superior risked economics allow. Kiwetinohk expects, however, to also maintain its own back-up capability to sequester CO_2 in brine aquifers.

Kiwetinohk's planned power projects include:

1. **Solar and Wind Renewables** – Utility-scale projects.

2. ***Firm Renewable*** – High-efficiency gas-fired plants that have the ability to quickly stabilize the portion of the power grid that is fed by wind and solar generation equipment which can be a more volatile source of supply.

3. **NGCC** – NGCC plants that are significantly more efficient than existing coal retro-fits and simple cycle gas-fired assets.

Kiwetinohk intends to adapt, extend and apply existing CCUS technologies for deployment with both the *Firm Renewable* and NGCC natural gas-fired power generation equipment.

Kiwetinohk also aspires to advance its ability to store CO_2 in underground storage reservoirs. The ability to capture and store CO_2 from natural gas supplied power generation facilities allows for low-emission power generation. Underground storage capacity can be classified into three categories:

1. CO_2 injection into an oil reservoir for the dual purpose of enhancing oil recovery and long-term storage of a portion of the injected CO_2,
2. CO_2 injection for long term storage only, into a depleted oil or gas reservoir, and
3. CO_2 injection for long term storage into a deep saline aquifer.

Federal and provincial governments are in the process of determining and implementing policies and regulations, including financial instruments, to guide the industry toward their priorities among the three options. The Alberta government is in the process of considering expressions of interest for deep geological carbon sequestration. Kiwetinohk has also screened most of the oil pools in Alberta to identify those best suited to enhanced oil recovery ("**EOR**") by CO_2 flooding. Kiwetinohk has in-house capability to design CO_2 EOR projects and is assessing options to potentially acquire assets and advance projects as the regulatory environment for CO_2 sequestration (with or without EOR) and the opportunity to transfer CO_2 to another party become more clear.

Mid to Long-Term Objectives

In the mid to long-term, Kiwetinohk plans to combine hydrogen production from natural gas with power generation. Although the basic technology exists today, advancements in the hydrogen market, distribution infrastructure and a supportive fiscal regime are required for profitability. In the long-term, the Company expects hydrogen-natural gas blends, and then hydrogen, alone, to displace natural gas in many of its current uses. In the longer-term, technology may evolve to allow long-distance, high-pressure transportation of hydrogen. This might enable economic shipment of hydrogen from gas and/or renewable primary energy to markets around the world.

As a mid to long-term objective, Kiwetinohk plans to bring its natural gas production into equivalent proportion with its use of natural gas for electricity and hydrogen production.

Long term, aspirational goals include:

1. Growing to become a significant supplier of power to the Alberta power grid,
2. Burning natural gas for power consumption with CCUS,

3. Producing and consuming natural gas in nearly equivalent amounts from very low emissions natural gas production operations in Alberta and British Columbia,

4. Participating significantly in supplying hydrogen to the Alberta gathering and distribution and market infrastructure as it evolves,

5. Continuing to position in new low-emissions and green energy transition technologies within, and within reach, of the Alberta market, and

6. Attracting other businesses to integrate with the Company's power generation and hydrogen production hubs creating a circular economy, making a profitable business of providing energy, conserving waste heat and process water and CCUS to adjacent businesses and industries.

The Company expects to nimbly transition as the market conditions transition. The Company intends to choose its path in the future by selecting energy transition activities that it can do in a differentiated way. The Company's long-term goal is to be a leading competitor in the provision of clean energy vectors as measured by emissions intensity and cost of energy. In using the term "leading competitor" in this context, the Company means that it aspires to grow to a size that is relevant for the power and / or hydrogen markets and thereby also relevant to the public equity markets. The goals include broad equity analyst coverage across these respective industry verticals and, possibly, index inclusion so that the Company can continue to competitively finance energy transition activities. In short, Kiwetinohk is striving to be an Alberta market leader in the energy transition, delivering successful outcomes for all stakeholders.

Kiwetinohk's long-term strategic targets and strategy are not based on a budget or capital expenditure plans approved by the Board of Directors of the Company beyond 2021 and is not intended to present a forecast of future performance. Further, the fiscal, regulatory, technology and finance environments associated with the energy transition are evolving rapidly, making reliable specific long-term planning impossible. Although, long range planning can be unreliable, to participate in the energy transition sector today, the Company needs to develop and continually test and adjust a longer-term view. Because of this dynamic situation, there can be no assurance (and, in fact, it is unlikely) that Kiwetinohk's current strategy or plans will be realized as currently contemplated. See "*Risk Factors*".

TACTICAL CONSIDERATIONS SUPPORT KIWETINOHK'S STRATEGY

Where are Kiwetinohk's Operations Located Now and Targeted for the Future?

Montney and Duvernay: High-Quality Natural Gas, Opportunistic Crude Oil

Kiwetinohk is strategically looking to acquire high-quality natural gas production and development properties to supply its planned power and hydrogen operations. Generally, this need directs the Company's natural gas acquisition activity to the Duvernay formations in Alberta and the Montney formation in Alberta and British Columbia. To date, Kiwetinohk has acquired significant natural gas prone land positions in the Fox Creek region of northwest Alberta and the Drayton Valley – Rimbey region of west central Alberta.

The Company also strategically acquired a medium to heavy oil prone land position in the Clearwater formation in the Thorhild Radway region of north central Alberta with the intent to stabilize the Company's production profile.

For a full description of the Company's crude oil and natural gas properties, please see "*Description of Kiwetinohk's Business – Upstream Business Description*".

Power and Renewables: Access and Infrastructure Drive Project Site Selection

Kiwetinohk is in the process of acquiring lands for renewables and gas-fired projects based on its anticipated needs for potential renewable and power generation projects, which are outlined as follows:

- Solar power
  - segments of the electrical power grid with adequate take-away capacity for the power to be generated
  - sufficient contiguous land with high solar radiation intensity and supportive stakeholders
  - positive stakeholder engagement

- Gas-Fired Projects (Both *Firm Renewable* & NGCC)
  - segments of the electrical power grid with adequate take-away capacity for the power to be generated
  - CO_2 capture, gathering and distribution networks for
    - oil pools suited to CO_2 EOR
    - geologic formations suited to permanent sequestration of CO_2
  - high-netback gas fields which are currently owned or could be acquired at attractive cost
  - gas transmission pipelines with adequate delivery capacity
  - present or future hydrogen (supply) markets and infrastructure
  - positive stakeholder engagement

  - *Firm Renewable*
    - segments of the electrical power grid especially, but not exclusively, in areas that are most vulnerable to the intermittent nature of connected solar and wind power

  - NGCC
    - water available for industrial use

One matter that warrants specific focus is the location of gas-fired power projects relative to the Company's natural gas fields. Generally, Kiwetinohk's natural gas fields are not near points on the power grid that can accept large injections of new power. Alberta has a pervasive network of natural gas pipelines that were built to gather natural gas for Alberta and transcontinental markets. These legacy pipelines can often be used directly, or augmented at reasonable cost, to deliver gas to power plant locations that have been selected for other reasons (such as grid capacity, nearby CO_2 sequestration capacity and receptive landowners and communities). This means Kiwetinohk will likely generate power using gas from the midstream network as opposed to gas from dedicated pipelines from the Company's own gas fields. However, through the production of its own low-cost natural gas, the Company expects to be able to effectively control the input cost of its natural gas-fired power generation facilities, creating an expected competitive advantage. The Company's target is to use and produce approximately the same amount of natural gas – it does not require that the Company uses natural gas that it produced.

If and where practical, Kiwetinohk intends to seek location-dependent synergies such as location of gas-fired power generation near the Company's operations. Benefits of this strategy may include eliminating the possible need for natural gas storage, eliminating natural gas transportation tariffs, using the captured CO_2 for an EOR project operated by the Company or a partner/customer and distribution of low-emissions power for the requirements of the natural gas field. The Company also considers co-locating with other companies that need any of the Company's products or services for their operations. In applying for CO_2 disposal capacity the Company is aware of the broad industrial need for CO_2 sequestration capacity and that disposing of CO_2 for others, particularly clusters of plants in industrial hubs, may evolve into a lucrative business in itself.

Key Differentiator: Alberta's Resources, Markets and Infrastructure

The Company believes that Alberta's resources, markets and infrastructure will dictate the best energy transition strategies. Kiwetinohk has consolidated a high quality, infrastructure-rich oil and gas base operation that provides multiple years of drilling inventory. The Company believes that the natural gas reserves from this base of operations favorably position Kiwetinohk to develop its downstream power strategy and provide lower emissions energy with the support of carbon capture. Future company growth is currently focused on Alberta and the broader Western Canadian Sedimentary Basin ("**WCSB**"). Nearly all of Alberta lies within the WCSB, which provides certain attributes relevant to the energy transition:

- natural gas (and oil) resources that are globally significant in scale and quality,
    - the all-in cost of its natural gas resources is globally competitive,
    - abundant, mature oil developments offer significant CCUS capacity, in some cases, with CO_2 EOR potential, and
    - depleted gas pools provide CO_2 sequestration capacity or, in some cases, gas storage capacity,
- geological strata suited to permanent CO_2 storage,
- pervasive surface oil and gas gathering, processing and distribution infrastructure,
    - pipelines which can be converted to hydrogen / natural gas blend pipelines, and
    - gas processing plants with CO_2 extraction capability, and
- broad and deep availability of professional service providers skilled in oil and gas production and energy facility design, construction and operation.

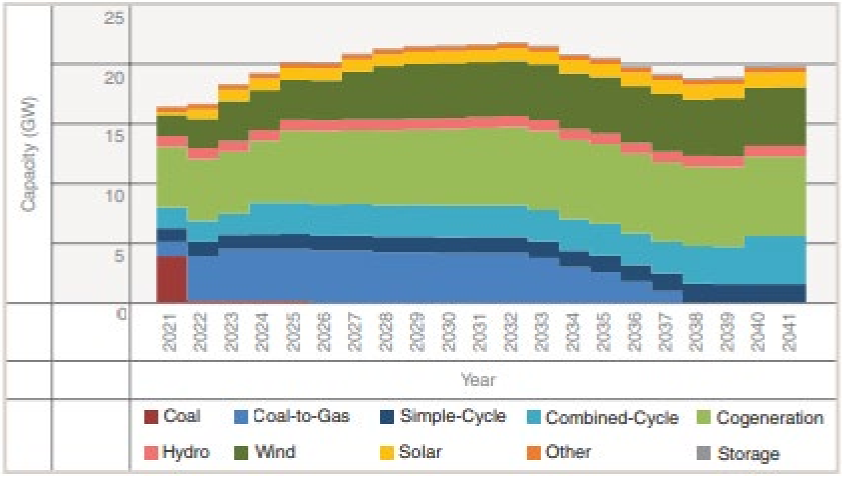
The Company believes that Alberta's deregulated power market facilitates entry and promotes competition. The Province has very modest import/export capacity for electricity. This simplifies forecasting future market conditions most often to supply and demand developments solely within the Province. In addition to this macro condition, wherein Alberta is effectively a "power island" (deregulated with modest import/export), the local market is also undergoing significant structural change. Over recent decades, coal-fired power generation was the largest primary energy source of electricity supply. All 5 GW of Alberta's current coal-fired power generation capacity is now either being retired or converted to natural gas. The expectation is that there will be no coal fired power generation by 2024. The Company believes that this relatively short window of time is one factor governing the opportunity window, with the other being carbon taxes. The Canadian carbon pricing regime (described immediately below) is spurring interest in the development of new power projects, in particular in Southern Alberta, which represents a rich opportunity base for renewable power projects: solar irradiance is high, while ambient temperatures are moderate (which are optimal conditions for solar panel deployment); and the wind resource is robust.

Year	2023	2024	2025	2026	2027	2028	2029	2030
Minimum Carbon Pollution Price ($ CAD/tonne CO_2e)	$65	$80	$95	$110	$125	$140	$155	$170

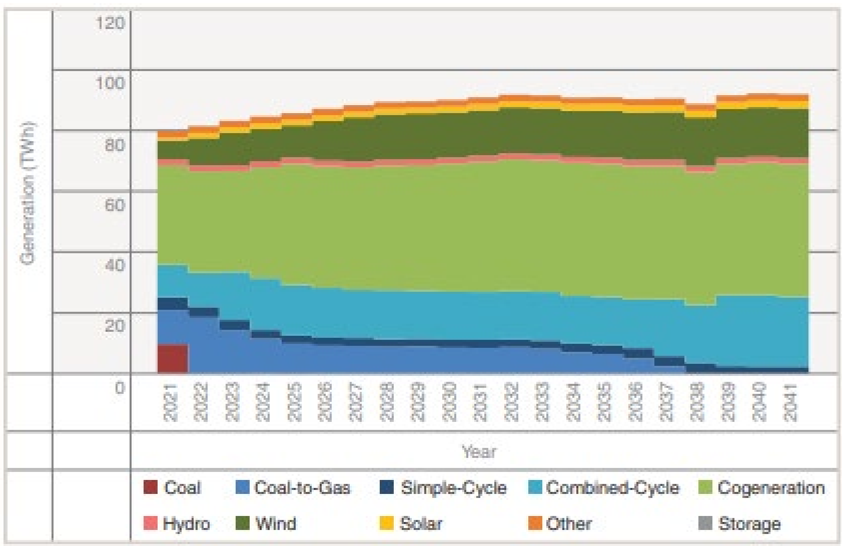
Finally, the number of specific new projects that has been submitted to the AESO queue is evidence that there are more potential power projects/proponents than there is actual space for new power generation on the physical power grid in southern Alberta. There is an abundance of superior locations for potential solar or wind power projects in southern Alberta, but a finite and shrinking number of locations on the power grid where there is room for new generation to be connected to the grid. The population in southern Alberta is quite sparse and the power grid is similarly currently quite limited in scope. The above conditions have created a renewable power rush with numerous developers proposing new projects and seeking power grid capacity.

Power market forecasts are provided by AESO and are shown below:

Reference Case: Capacity by Fuel Type



Reference Case: Alberta Generation



According to the AESO, the reference case depicts a changing generation landscape, with reduced reliance on coal generation and increased reliance on natural gas generation. Throughout the forecast term, natural gas fired technologies are expected to generate between 75 per cent and 82 per cent of annual electricity in the province. Renewable generation exhibits strong growth throughout the forecast term and also takes on increased reliance with the phase out of coal. According to the AESO, increasing amounts of variable generation may pose challenges to reliable system operations if these changes are not managed prudently.[5]

Evolution in the Alberta power market has created the following market characteristics:

- it is no longer protected by the low cost of coal,

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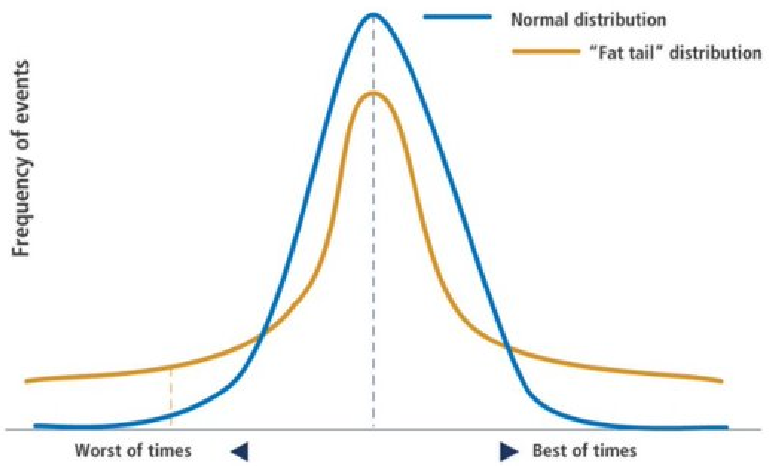
[5] "AESO 2021 Long Term Outlook" (June 2021), online: *aeso* <https://www.aeso.ca/assets/Uploads/grid/lto/2021-Long-term-Outlook.pdf>.

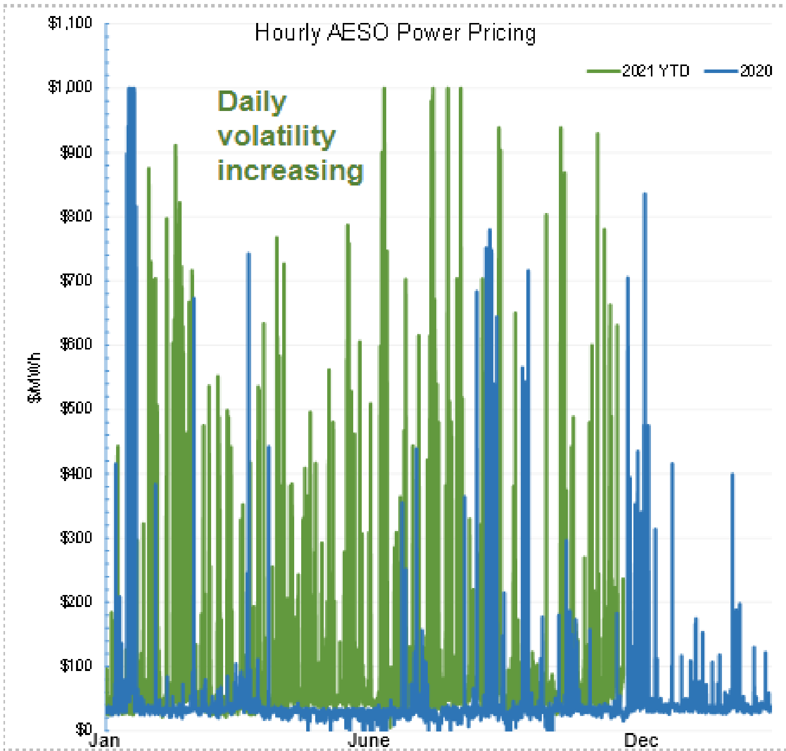
- it is much more directly connected/correlated to the price of natural gas,
- it is increasingly exposed to the fundamental unpredictable intermittency that comes from material penetration by renewable power sources, and
- reliable, dispatchable power now contributes a lower portion of the grid power make-up.

Kiwetinohk expects all these factors to drive a fundamental shift in the Alberta power market where prices were once quite predictable, reasonable and exposed to only rare periods of extreme price, to a new market condition where extreme power prices (both low or high) can be expected to be much more common and/or sustained for longer periods of time.



The above graphic depicts the expected trend, showing a more conventional power market with a normal distribution. Kiwetinohk expects the statistical distribution of power prices in Alberta to move from something near a "normal distribution", to a "fat tail distribution" of power prices driven by more extreme pricing events.

While the Alberta power market remains very early in the transition to maximum reliance on natural gas and renewable power, with no excess coal capacity backstop, Kiwetinohk believes that power prices in the Province have already started to demonstrate price behavior showing an increasing frequency of volatility in power prices with a current focus on "right tail" events (or high-power prices).



Source: Prepared by management of the Company based on data made available by the AESO.

As the market share of renewables accelerates, the Company believes more "left tail" events (or low power prices) can be expected to occur whenever renewable power generation is highly active (windy or sunny conditions). On the other side of the distribution, more "right tail" events (or high-power prices) can be expected whenever conditions are unsuited to renewable power peak performance.

The Company believes that the fundamental transition in the nature of the Alberta power market presents a material opportunity for Kiwetinohk. The Company believes that most of the existing gas fired power generation capacity in the Province is not optimized for the kind of rapid change in dispatch capacity that will be necessary for optimal economic performance in a period of fat-tail power price distribution, at the same time that much of the existing gas-fired power generation capacity is not efficient from either a GHG emissions or heat rate perspective. Kiwetinohk believes that the Alberta power market needs low-cost, low-emissions power generation capacity that responds quickly, efficiently to "right tail" situations. The Company believes existing gas fired power generation capacity is not optimized for rapid changes in power dispatch and it is exposed to further competitive challenges by the growing cost of CO_2 emissions.

Kiwetinohk intends to take advantage of these trends by building a portfolio of power generation projects including solar and wind renewable, dispatchable *Firm Renewable* gas-fired power generation and base-load NGCC.

As envisioned, overall, the Kiwetinohk portfolio will target material energy transition performance gains compared to existing grid projects on average (both emissions and heat rate gains) as they are currently configured. The natural gas-fired projects are planned to be located to facilitate access to CO_2 sequestration capacity and designed and, to an appropriate degree, selected and constructed to accommodate the addition of CCUS. In the short to mid-term, the Company envisions a need for new utility scale renewable power projects that are optimized for technology and location. Kiwetinohk intends to build a new portfolio that is optimized for an expected new reality of fat tail distribution of power prices where the cost of GHG emissions or emissions abatement will also play an ever-increasing role in economic success or failure.

As regulatory and technical evolution makes profitability more likely, CCUS may be added to the Company's gas-fired power projects. Kiwetinohk expects that in most cases CCUS will be included from the start, however pilot projects may be required for novel technologies or novel applications. Social and economic license are both expected to "demand" that carbon capture is part of any gas-fired power generation in the future. This expectation also highlights the final fundamental appeal to the Company of the Alberta market. Alberta enjoys a globally relevant capacity for CO_2 storage capacity. Alberta has significant potential for either permanent storage or utilization of CO_2 for EOR. EOR is a process which inherently returns some of the CO_2 to the surface with the produced oil. The permanent storage capacity for CO_2 includes both aquifers and depleted hydrocarbon pools. Kiwetinohk believes that it has reviewed most of the oil reservoirs in Alberta in order to identify suitable candidates for potential EOR. Kiwetinohk is also active in the current Provincial Government process for defining new rules and expectations for sequestration strategies and industry development.

PURPOSE, MANDATE & CORPORATE CULTURE

Kiwetinohk's mandate is to provide its stakeholders with tangible energy, economic, environmental and social benefits through the successful management of its assets, business and growth projects related to the production, delivery and sale of low and zero carbon energy products.

Kiwetinohk's vision is to meet its stakeholders' evolving energy needs through ongoing leadership in the energy transition. This includes making significant investments in natural gas, natural gas power generation, carbon management and renewables power to support North America's climate change, energy and electrification goals as the world pursues a net zero economy by 2050.

Kiwetinohk's Prime Goal

Kiwetinohk is committed to maintaining high standards of corporate governance and to embedding a corporate culture centered around its founding stakeholder principles and prime directive, namely:

> *At Kiwetinohk, we are transitioning to become a sustainable energy company and we recognize that the fortunes of stakeholders are inseparable. In the long term, for any to benefit, all must be engaged and contribute. We acknowledge these stakeholders and the duty to address the reasonable desires of each:*
>
> - *People, everywhere, who seek to protect the environment want us to reach beyond compliance and find ways to lead the energy industry in reducing the environmental impact of our activities, restoring disturbed land and reducing GHG emissions intensity,*
> - *Governments and regulators want us to comply with all laws and regulations and to advise them of changes that would enable the industry to better serve society,*
> - *Communities most impacted by the Company's activities, including Indigenous communities, want to participate in planning, building and operating projects and in restoring the land when the projects are done,*
> - *Industry partners want us to honor our arrangements and reasonably accommodate change and adaptation,*
> - *Customers want us to reliably deliver our products at the specifications and in the amounts that we forecast,*
> - *Suppliers and service providers want an opportunity to compete for our business, to be paid promptly and fairly, and to contribute to the evolution of our business,*
> - *Employees want an energizing, inclusive, positive work environment where everyone is treated with dignity and respect, to be compensated fairly and a safe and healthy workplace,*

- *Investors want strong returns on their investment, effective communication and management of risks, environmental, social, financial and reputational.*
- *We, at Kiwetinohk, see ourselves in the business of serving our stakeholders and working together with them to transition to sustainable energy. By engaging all of our stakeholders openly and honestly and by encouraging their participation in our business, we expect to best serve each of them.*

*This goal of building a better enterprise by stakeholder engagement and accommodation is our "**prime directive".** The pursuit of this objective is the foundation for Kiwetinohk's management conduct policies, its decision making and its actions.*

Corporate Culture and the Tools Used to Differentiate

The Company believes that its corporate culture differentiates it from its competitors and provides an advantage in the pursuit of the Company's objectives. The pillars of the Company's culture include:

- Rigorous focus on operational effectiveness, including the pursuit of economics of scale in purchasing and logistics and strategic partnering with, and continuous engagement of, service providers,
- Full-cycle, long-range planning focused on probabilistic analysis, ARO inclusion and scenario and risk and opportunity analysis,
- Pursuit of high-graded asset opportunities, targeting top quartile asset development opportunities,
- Technological awareness, application and planning, and
- Stakeholder engagement.

Technology

The Company strives to monitor technologies that can enhance and / or threaten the business. Through rigorous risk and opportunity analysis the Company selects technologies in which it invests directly and those it continues to monitor and those it discards from active review. Most of the Company's technology investments are extensions or adaptations of existing proven methods, while some are significant departures. Below are some examples of technologies Kiwetinohk has invested in or continues to actively study and monitor developments:

- Optimal gas well design, including controllable factors such as lateral length, lateral separation, stage spacing, perforation clusters per stage, hydraulic fracture fluid chemistry, slurry volume, proppant characteristics and proppant concentration and slurry pump rate. By experimenting with the controllable factors over the past decade the industry has greatly reduced the total cost of resource extraction. Kiwetinohk is experimenting on well design where it sees upside potential far outweighing downside cost.
- Kiwetinohk is planning to pilot test a new solvent on a *Firm Renewable* plant that is in the engineering and approval process, yet to reach final investment decision ("**FID**").

As in the above examples, Kiwetinohk looks to develop, adapt and apply new technologies where the risked upside far out-weighs the risked downside. In fields of endeavour such as the energy transition, where technology is rapidly evolving, the Company believes that any company that avoids technology is likely to be surpassed by its competitors and become non-competitive.

Government stakeholder engagement

Kiwetinohk believes that to be profitable in the rapidly evolving energy transition economy, activities must be sustainable and to be sustainable activities must be profitable. Kiwetinohk also believes that society's best hope for successfully abating climate change is for governments to unleash and direct the power of the free market system, setting rules that apply to everyone, and subsidizing, if at all, all participants equally. Management of Kiwetinohk has been active, directly and in independent committees, informally advising both the Federal and Provincial governments related to the transition economy. So far, governments have been active participants in the energy transition economy, picking companies and technologies to support, to ignore and, even, to suppress. While Kiwetinohk is eager to collect any subsidies available for its business, the Company is reluctant to enter a business if profitably executing opportunities in that business relies on subsidies. Climate change is a global challenge requiring global cooperation. In the long term, the Company believes that global success in the struggle to limit climate change will arise from adoption of equal and coordinated programs among the world's major economies. If GHG emissions have a cost, as Kiwetinohk believes they do, then their emission should have a price (such as a carbon tax) to offset that cost and motivate investment in emissions reduction. Ultimately, for society to achieve net zero, GHG emission avoidance needs to be less expensive than emission. What that means for Kiwetinohk is a need to analyze its investments as to competitiveness, relative to other sources of its products, in both emissions intensity and profitability.

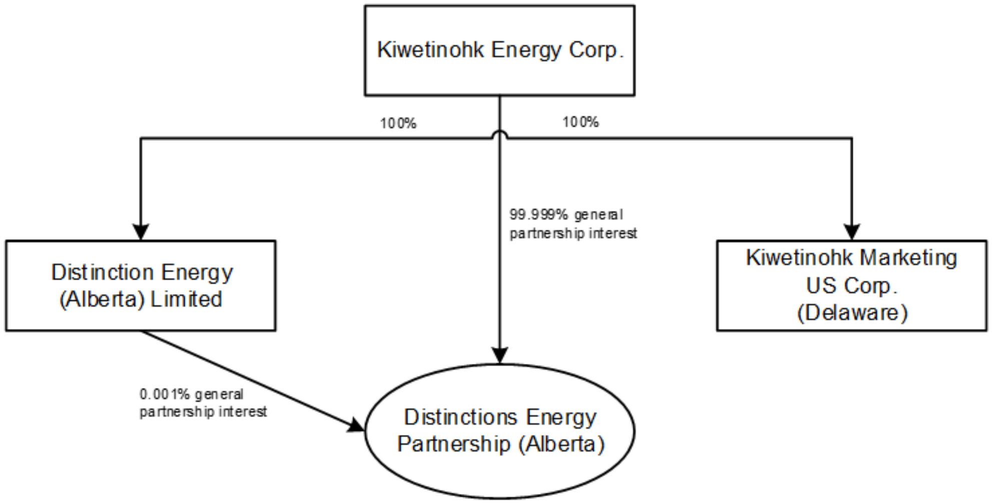
CORPORATE STRUCTURE

The Company was formed on February 12, 2018 by articles of incorporation under the ABCA as "2090763 Alberta Ltd.". On August 10, 2018, the Company amended its articles to change its name to "Kiwetinohk Resources Corp.". The Company subsequently amended its articles on May 24, 2019 to remove the restriction on the number of holders of securities of Kiwetinohk.

In connection with the Business Combination, Kiwetinohk continued under the CBCA on August 31, 2021, and amalgamated with Distinction on September 22, 2021, pursuant to the Business Combination Agreement under the name "Kiwetinohk Energy Corp.". In addition, on September 22, 2021, in connection with the Business Combination, the Company completed the Consolidation.

Kiwetinohk's principal office is located at Suite 1900, 250 – 2nd Street SW, Calgary, Alberta, T2P 0C1 and the registered office of the Company is located at 3700 Devon Tower, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

The following organizational chart sets out the Company's organizational structure and its material subsidiaries as of the date of this AIF.



GENERAL HISTORICAL DEVELOPMENT OF THE BUSINESS

Three Year History

2018

- August 20 - Kiwetinohk entered into subscription agreements with management, directors and ARC, a private equity investor. Under Kiwetinohk's subscription agreement with ARC, ARC received the option to invest, directly and through co-investors, up to $250 million at $1.00 per Common Share (on a pre-Consolidation basis), subject to approval of both ARC and the Board, and ARC entered into an initial commitment to subscribe for $100 million of Common Shares. At this time, Kiwetinohk and ARC entered into the Shareholder Agreement.

- August 29 - Kiwetinohk entered into a farm-in and option agreement with Journey Energy Inc. to jointly develop the Gilby Area in Central Alberta and established a position in the West Central Alberta Duvernay (the "**Journey JV**").

- At December 31, Kiwetinohk had drilled the first two commitment wells and re-entered the first well of the option phase in the Journey JV. Kiwetinohk also acquired 167.5 gross (167.5 net) sections of land in the Drayton Valley region of West Central Alberta during 2018 and early 2019.

2019

- April 29 - Kiwetinohk entered into a subscription agreement with ARC for an additional $100 million at $1.00 per Common Share (on a pre-Consolidation basis), bringing the aggregate ARC subscription amount to $200 million in Common Shares at $1.00 per Common Share (on a pre-Consolidation basis).

- July - pursuant to other subscription agreements, Kiwetinohk received a further equity commitment of $23.2 million from employees, founders, friends and family at $1.00 per Common Share (on a pre-Consolidation basis).

- September 30 - Kiwetinohk had drilled and completed its second well of the option phase in the Journey JV and had a total of four wells tied-in and on production.

- December 31 - ARC had invested $115 million and had committed through subscription agreements a further investment of $85 million, subject to the Board calling and ARC approving such investments.

- December 31 - Kiwetinohk had entered into subscription agreements totaling $225.4 million in Common Shares at $1.00 per Common Share (on a pre-Consolidation basis) from ARC and employees founders, friends and family, including an additional small private placement, with ARC having a further option to invest $50 million for up to $275.4 million in total aggregate equity proceeds.

2020

- April 5 - as a result of the challenging economic conditions due to the failure of the Organization of the Petroleum Exporting Countries ("**OPEC**") and Russia to reach an agreement on oil production cuts and the outbreak of the COVID-19 virus, Kiwetinohk shut in production on its four wells from the Journey JV.

- June 8 - Kiwetinohk resumed production on three of its four wells from the Journey JV that had been shut in on April 5, 2020.

- July 5 - Kiwetinohk entered into a capital investment agreement with Distinction (then known as Delphi Energy Corp.) whereby Kiwetinohk agreed to make a $22.9 million investment (referred to below as the Initial Distinction Investment) in Distinction concurrent with the successful implementation of the restructuring plan by Distinction to restructure and exit from the *Companies' Creditors Arrangement Act* ("**CCAA**"). Kiwetinohk also entered into an investor agreement with Distinction and Luminus, which resulted in Kiwetinohk being granted certain nomination rights and other governing controls in respect of Distinction. Concurrently, Kiwetinohk entered into a management services agreement with Distinction, which resulted in Kiwetinohk providing management services to Distinction in exchange for a monthly fee payable to Kiwetinohk upon closing of the Initial Distinction Investment.

- July 17 - Kiwetinohk acquired complementary crude oil and natural gas properties in the Thorhild region in north central Alberta for $2.5 million which included one producing well. Concurrent with this transaction, Kiwetinohk also assigned 7.75 sections of land to the seller, retaining a 5% gross overriding royalty on future production on those 7.75 sections.

- September 8 - Kiwetinohk completed the purchase out of receivership of complementary crude oil and natural gas properties in the Thorhild region in north central Alberta for $935,000, along with the assumption of approximately $800,000 in existing environmental liabilities.

- October 16 - Kiwetinohk made a $22.9 million investment into Distinction (the "**Initial Distinction Investment**") pursuant to a capital investment agreement for a 25% ownership interest in Distinction and entered into a participation agreement with respect to an area of mutual interest. The Initial Distinction Investment included the Distinction Warrants.

- December 31 – As of December 31, 2020, ARC had invested $169.0 million and committed a further investment of $31.0 million through subscription agreements.

Recent Developments

- On January 15, 2021, Kiwetinohk exercised its Distinction Warrants for $40 million. Upon completing this transaction, Kiwetinohk's equity ownership in Distinction increased to 50% plus one additional Distinction Share (the "**Subsequent Distinction Investment**" and, together with the Initial Distinction Investment, collectively, the "**Distinction Investments**").

- On February 17, 2021, Distinction and Kiwetinohk entered into an acquisition opportunity agreement in respect of Distinction's commitment to participate with Kiwetinohk as to 50% of a $335 million acquisition, including $15 million in potential contingent payments based on future commodity prices, entered into by Kiwetinohk for certain crude oil and natural gas interests in the Simonette and other areas of northwest Alberta, whereby the parties agreed, among other things, that the acquisition and the purchase price (subject to adjustments) would be shared equally between them (the "**Simonette Acquisition**"). The Simonette Acquisition closed on April 28, 2021 for an adjusted purchase price (not including potential contingent payments) of approximately $296 million.

- Additionally on such date, Luminus, 1266580 B.C. Ltd. (an affiliate of Luminus), Kiwetinohk, Distinction and DEP entered into a settlement agreement providing for, upon closing of the Simonette Acquisition, among other things, the payment by Kiwetinohk of $4.25 million to 1266580 B.C. Ltd. and the termination of the participation agreement entered into among them on October 16, 2020 with respect to the area of mutual interest described therein, the amendments to the Distinction investor agreement and the Distinction management services agreement described above and the establishment of a listing committee of the Distinction Board to facilitate the listing of the Distinction Shares on a recognized exchange.

- On March 6, 2021, Kiwetinohk completed an equity line of credit cash call of $9.5 million. In addition, ARC finalized share subscription agreements for the optional $50 million equity investment, resulting in the full satisfaction of the ARC equity commitments described above. Furthermore, in preparation for the closing of the Simonette Acquisition, ARC finalized additional share subscription agreements for a further optional $25 million equity investment in Kiwetinohk increasing the aggregate ARC equity commitment to $275 million. See "*Principal Holders of Voting Securities*".

- On April 28, 2021, in connection with the Simonette Acquisition, Kiwetinohk closed an equity private placement for net proceeds of $104 million representing the remainder of all outstanding subscription agreements with ARC, founders, management, friends and family.

- On April 28, 2021, Kiwetinohk closed the Simonette Acquisition and entered into a $97.5 million credit agreement with a syndicate of banks and made an initial draw of $33 million. Distinction entered into a $127.5 million credit agreement with a syndicate of banks and made an initial draw of $63.3 million.

- On May 24, 2021, Kiwetinohk had closed on $33.3 million of new equity private placement proceeds in connection with the Simonette Acquisition.

- On June 28, 2021, Distinction and Kiwetinohk entered into the Business Combination Agreement. The Business Combination was completed on September 22, 2021.

- On August 31, 2021, in anticipation of completion of the Business Combination, Kiwetinohk continued under the CBCA.

- On September 15, 2021, the Company appointed Janet Annesley as Chief Sustainability Officer.

- On September 22, 2021, Kiwetinohk and Distinction completed the Business Combination and consolidated the credit agreements of Kiwetinohk and Distinction into a single $225 million Credit Agreement with a syndicate of banks.

- On November 11, 2021, the Company appointed Mike Backus as Chief Operating Officer (Upstream Division).
- On November 24, 2021, the TSX conditionally approved the listing of the Common Shares. Listing is subject to the Company fulfilling all of the requirements of the TSX on or before February 22, 2022.
- On November 25, 2021, William (Bill) Slavin resigned from the Board.

Significant Acquisitions

Each of the Distinction Investments, the Simonette Acquisition and the Business Combination may be considered a "significant acquisition" of a "related business" for the purposes of Part 8 of National Instrument 51-102 – *Continuous Disclosure Obligations*.

Acquisition	Details
Distinction Investments	On October 16, 2020, Kiwetinohk completed the Initial Distinction Investment. On January 15, 2021, Kiwetinohk completed the Subsequent Distinction Investment. Kiwetinohk considered a wide range of factors including market conditions, historic prices paid for assets in the area, estimated cash flows and multiples paid in the market for comparable cash flowing assets, reserves and estimated recoverable resources, discounted cash flow analysis for producing reserves and various future development scenarios and current plus future abandonment liabilities in assessing the purchase price under the Distinction Investments. The ultimate purchase price for the Distinction Investments was determined through negotiation between Kiwetinohk and Distinction.
Simonette Acquisition	On February 17, 2021, Kiwetinohk and Distinction entered into various agreements in connection with a $335 million acquisition of certain crude oil and natural gas interests in the Simonette and other areas of northwest Alberta (collectively, the "**Simonette Assets**"), whereby the parties agreed, among other things, that the Simonette Acquisition and the purchase price (subject to adjustments) would be shared equally between Kiwetinohk and Distinction. The purchase price includes up to $15 million of contingent payments that will be required if average crude oil prices exceed the reference price for WTI of USD $56.00 per barrel in 2021 and USD $62.00 per barrel in 2022 of which $3.75 million of the contingent payments may be settled in Common Shares of the Company at the sole option of the Company. Kiwetinohk funded its $160 million ($145.7 million net of interim closing adjustments) share of the purchase price through its remaining $79 million equity line of credit, issued an additional $25 million of equity financing and drew $33 million on a $97.5 million senior secured extendible revolving credit facility per the Credit Agreement. Distinction funded its $160 million ($145.7 million net of interim closing adjustments) share of the purchase price through available cash and drew $63.3 million on a $127.5 million senior secured extendible revolving credit facility. The Simonette Acquisition had an effective date of January 1, 2021 and closed on April 28, 2021.

Business Combination	On June 28, 2021, Kiwetinohk and Distinction entered into a business combination agreement providing for the acquisition by Kiwetinohk of all of the issued and outstanding Distinction Shares not already owned by Kiwetinohk. The Business Combination was completed on September 22, 2021.

DESCRIPTION OF KIWETINOHK'S BUSINESS

The scope of Kiwetinohk's anticipated energy transition business includes the following core elements:

1. Renewable solar and wind power development and operation

2. Low-emissions, natural gas-fired power generation of two types:

    a. *Firm Renewable*, the Company's term for high efficiency, flexible-output, low emissions, internal reciprocating engine driven power generation and

    b. Natural gas combined cycle,

3. CCUS,

4. Production of hydrogen, and

5. Development and production of relatively low-emissions, low-all-in cost natural gas.

The pursuit of these core elements may bring or has already brought into Kiwetinohk's business some or all of the following:

- Oil, condensate and natural gas liquids production, some concurrent with gas from the Company's assets, some acquired for commercial reasons,

- Commodity marketing capability including:

    - Natural gas
    - Natural gas liquids
    - Condensate
    - Crude oil
    - CO_2
    - Hydrogen
    - Financial instruments such as carbon tax credits,

  (The hydrocarbon capability is already in place, buying gas for the Company's excess transportation capacity and selling the Company's production.)

- Managing (for profit) asset retirement obligations of other petroleum developers,

- Providing CO_2 to CO_2 EOR projects owned by others or by Kiwetinohk,

- Permanent storage of CO_2 in geological strata for Kiwetinohk and other CO_2 producers,

- Production of clean products from natural gas as part of circular economy-motivate clean energy hubs, and

- Providing natural gas and / or CO_2 to and CO_2 sequestration for manufacturing operations owned and operated by others.

Kiwetinohk's energy transition strategy seeks to address the following societal needs for sustainable energy development and production:

1. adequacy of supply,

2. reliability of supply,

3. greatly reduced (eventually proposed to be zero) GHG emissions, and

4. profitable, free-cash-flow generating assets enabling the Company to attract capital investment.

Kiwetinohk's Integrated Primary Energy to Low-Carbon Energy Strategy

The Company's main goal is to provide low/zero carbon energy in the form of electricity and hydrogen. To compensate for some of the unreliable/ intermittent nature of output from its anticipated solar and wind power plants, Kiwetinohk plans to build *Firm Renewable* gas-fired plants that are intended to nimbly compensate for volatility in supply and demand. The Company is also planning reliable base load power generation from efficient NGCC plants. Kiwetinohk expects to investigate the feasibility of CCUS and may deploy CCUS systems to achieve low emissions levels from its natural gas-fired plants.

The Company's objective is to have natural gas production and consumption approximately in balance so that the Company can account for emissions from the use of natural gas and reduce risk from gas price volatility. Kiwetinohk is presently taking the view that it is important to have "resource to CO_2 sequestration" control on the amount of natural gas it produces, not necessarily the specific natural gas molecules it produces.

Kiwetinohk currently holds high quality natural gas resources in the Montney and Duvernay tight/shale formations near Fox Creek, Alberta. The Company continues to look for additional natural gas resources both proximal to its Fox Creek assets and elsewhere within Alberta and British Columbia. Key factors that the Company seeks in natural gas resource asset acquisitions include:

- high-quality, low all-in cost per boe of recoverable resource (capital, operating, royalty, transportation and marketing costs) as reflected in discounted break-even price,

- low-risk / high-reward upside potential from technology and operational effectiveness,

- adequate transportation to get the natural gas to market or other desirable locations to build a power or hydrogen project to use the gas, and

- ownership of upstream facilities and infrastructure, allowing it to reduce upstream operating costs and pursue new potential midstream service revenue opportunities.

The Company expects the combination of low-cost natural gas produced from Kiwetinohk's upstream resources, with its planned natural gas-fired power projects, to increase the gross margin to the Company through participation in the full value chain from upstream resource to clean, low emissions power generation. As a result, the Company expects to diversify its revenue streams and deliver more sustainable cash flows through a greater diversity of end markets for its produced natural gas, including end power markets that can be exclusive to Kiwetinohk.

Current Power Generation and Hydrogen Production Projects

The Company is advancing its plan to identify, capture and develop greenfield and/or brownfield renewable and natural gas-fired power generation projects. The Company has identified three pillars of low carbon natural gas-fired power generation and renewable energy projects that it intends to pursue in the near term:

1. utility scale solar and/or wind power,
2. *Firm Renewable,* and
3. large-scale NGCC power.

The AESO has a six-stage process[6] that power projects are required to follow to achieve connection to the electric grid and be able to operate. Stages 1 – 2 include project definition, site selection, engineering design and cost estimates. Stages 3 – 4 include regulatory preparations and applications and the Generating Unit Owner's Contribution ("**GUOC**") payment. Stages 5 – 6 are construction and close out. In addition to AESO granting grid access, project proponents require approval from the Alberta Utilities Commission and Alberta Environment and Parks. These approvals have overlapping requirements and they are pursued concurrently.

Kiwetinohk has invested considerable time and money in developing its portfolio of attractive power and hydrogen projects. This development work has included preparation of preliminary designs, performance estimates and preliminary cost estimates as part of a staged process that includes stages of increasing refinement and estimate quality as part of the process the Company uses to advance projects. The intent will be to proceed towards final design, final performance projection or cost estimate, full regulatory approval and internal and external funding. Early-stage design factors and the status of each project are included in the following tables:

Kiwetinohk Power Generation Projects in Active Early-Stage Development[4]

Type	Location	Power[1] (nameplate/net to grid)	AESO stage	Total Installed Cost [2,3]	Site	Comments
Solar 1	South AB	600 MW 400 MW +/-1%	2	$655 million Class 3	Option secured	Environmental survey work is done AUC application underway Interconnection capacity available
Solar 2	South AB	450 MW 300 MW +/-1%	1	$492 million Class 3	Option secured	Environmental survey work is done
Firm Renewable 1	NW AB	101 MW 97 MW +/-1%	1	$175 million Class 3	Geo-technical completed Land acquisition in progress	Indigenous consultation: adequacy received FEED near completion CCUS pilot of a new solvent in consideration CCUS Pre FEED nearing completion

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[6] "Connection Process", online: *aeso* <https://www.aeso.ca/grid/connecting-to-the-grid/connection-process/>.

Type	Location	Power[1] (nameplate/net to grid)	AESO stage	Total Installed Cost [2,3]	Site	Comments
						AUC application underway Gas pipeline service application submitted
NGCC 1[5]	Central AB	500 MW 414 MW +/-10%	1	$875 million[7] Class 4 Class 4	Site selected Land acquisition in progress	Gas pipeline service application submitted Interconnection capacity available FEED RFP in progress
NGCC 2	North AB	500 MW 414 MW +/-10%	1	$875 million[7] Class 4	Site selected Land acquisition in progress	Investigating synergies with nearby CO_2 EOR Gas pipeline service inquiry commenced Interconnection capacity available FEED RFP in progress

Type	CO_2 Emissions Intensity (t/MWh)[6]		Heat Rate (MJ/kWh)		Capacity Factor	Earliest Date	
	without CCUS	with CCUS	without CCUS	with CCUS	with CCUS	FID/ Construction	Operation
Solar 1	N/A	N/A	N/A	N/A	28.4%	Q3 2022	Q4 2024
Solar 2	N/A	N/A	N/A	N/A	28.4%	Q2 2023	Q2 2025
Firm Renewable 1	0.443 +/-5%	0.400 +/-5%	7.6 +/-5%	7.89 +/-10%	50% peaking / 90% PPA with CCUS	Q3 2022	Q1 2024
NGCC 1[5]	0.350 +/-5%	0.045 +/-5%	6 +/-5%	6.62 +/-10%	90% with CCUS	Q3 2024	Q3 2027
NGCC 2	0.350 +/-5%	0.045 +/-5%	6 +/-5%	6.62 +/-10%	90% with CCUS	Q1 2023	Q1 2026

Notes:

(1) Power numbers include net available for grid for plants including CCUS load as applicable and overbuild of solar nameplate to increase capacity factor and maximize grid connection.

(2) Total installed cost numbers exclude carbon capture and sequestration. CCUS costs estimated (not American Association of Cost Engineering ("**AACE**") consistent) to be 60 to 100% of the total installed cost.
(3) Total installed cost estimates are classified in a manner consistent with AACE standards. See "*Risk Factors*".
(4) None of the Company's planned power generation projects have a final design, performance projection or cost estimate, or full regulatory approval or internal or external funding. There is no assurance that the power generation projects will proceed as described or at all. See "*Risk Factors*".
(5) The Company intends to conduct a pilot test of CCUS on one engine. The cost of this pilot project is included in total installed cost.
(6) Losegun gas composition used for Firm Renewable 1.
(7) Does not reflect the cost of CCUS, which the Company believes would cost an additional 60-100% of total installed cost.

The early-stage numbers listed in the above tables are preliminary in nature. The class of the cost estimate and the AESO stage gate status is indicated in the table suggesting the status of progress through the design, evaluation, screening, grid access, stakeholder consultation and approval. At an appropriate stage in the design process, Kiwetinohk expects to pursue project financing. The Company expects that the design, performance parameters, performance evaluation, regulatory approvals and financing will be in place before the Company will make its FID.

In addition to the above projects, Kiwetinohk is in continual pursuit of new greenfield project locations and greenfield projects that have secured sites and have been advanced to an early stage of regulatory approval by competitors in the new project development space. This includes the investigation of opportunities to use the Company's 120 mmcf/d of liquids-rich natural gas production currently transported on the Alliance pipeline for the greater Chicago market. Kiwetinohk meets the contract obligation through the delivery of gas that it produces and gas that it acquires from competitors. The Company is looking at alternative markets for its produced gas and at sources of gas to fuel planned power generation projects. The Company's current goal is to achieve and then maintain production of natural gas and use of natural gas for low-carbon energy production in near balance. The Company's scope of business also includes wind renewable power generation but no sites have been secured yet.

Solar Power – Projects in Development

Kiwetinohk's renewable energy strategy currently focuses on solar power project development. Currently Kiwetinohk is advancing two projects through early-stage development with pre-FEED and the regulatory approval process. These projects are planned for southern Alberta and are the cornerstones of the Company's current renewable energy development portfolio.

Kiwetinohk undertakes a comprehensive screening process to select potential sites for solar power development, reviewing locations based on: (a) interconnection (AESO grid) capacity availability and cost modelling; (b) environmental factors; (c) landowner considerations; and (d) future scalability. Kiwetinohk has secured options to lease lands which rank favourably across the screening criteria and that Kiwetinohk believes would be sufficient in total to support 650 to 800 MW of solar power generation capacity spread between the first two greenfield projects in the Kiwetinohk solar portfolio. The first grid-connected Kiwetinohk development project in southern Alberta is currently expected to be up to 400 MW and is progressing through AESO Stage 2. The second development project, also expected to be up to 400 MW, is in immediate proximity to the first project and is now in AESO Stage 1. Management intends to maximize the solar development on its optioned lands (through future new projects), with the balance of any lands not used for grid-connected solar to potentially target a "behind the fence" industrial solar use application.

Kiwetinohk is currently working on additional land acquisitions for further greenfield solar developments while also reviewing potential acquisitions of third-party early-stage solar and wind developments. For its renewable power portfolio overall, Kiwetinohk targets economies of scale, optimal location on the grid and emerging technologies for equipment and design, particularly for solar, to strive to secure economic advantage relative to the solar project peer group in Alberta.

Kiwetinohk has a portfolio of solar technologies and designs for its anticipated solar developments that it believes can provide a superior risk and reward profile to its projects above and beyond optimal size (minimize costs) and location (maximize revenue) criteria:

- Solar Panels: Kiwetinohk targets bi-facial efficiencies at the upper extreme of available technologies that are de-risked; panels with superiority in generation capacity; and panels with material efficiency advantages.

- Inverters: Kiwetinohk targets the upper end of commercialized technology efficiencies and targeting a particular modular design that reduces both the scale and frequency of unscheduled downtime events (maximizing asset utilization).

Solar projects are expected to generate carbon offset credits that Kiwetinohk could either use to net against its own emissions or "bank and sell" when the cost of CO_2 is expected to increase. Kiwetinohk will also look to maximize solar renewable output overall by coupling it with its *Firm Renewable* gas-fired power to provide the cleanest form of base-load power. Kiwetinohk's potential unique offering of "fully back-stopped" renewable power will also create new opportunities for future power purchase agreement ("**PPA**") offerings.

***Firm Renewable* – Projects in Development**

The Company's most advanced gas-fired power project is a *Firm Renewable* project. A site has been selected and geotechnical surveys have been completed, community consultation is underway, gensets have been selected and the FEED work and cost estimate is nearly complete. The Company has been working with a well-known manufacturer and its partner, an engineering, procurement and construction management firm, to develop a turnkey proposal to supply and construct the first project. Kiwetinohk is currently exploring options for financing the project.

Firm Renewable is the Company's term for high efficiency, flexible-output, low emissions, internal reciprocating engine driven power generation. These gensets are able to respond very quickly to supply power as volatility of grid supply and demand require. Supply volatility has proven to be a problem for power grid systems as they have taken on a high percentage of renewable wind and solar power. The engine/generator sets that Kiwetinohk is pursuing are designed to operate at relatively high efficiency (for simple cycle thermal power) of mid 40s percent and present designs can tolerate up to 15% hydrogen in the fuel gas. The machines are rated to accelerate from off to full power in less than four (4) minutes and they operate efficiently over a broad range. The whole plant, with nine (9) individual engine-generator sets, is expected to have the capacity to quickly and efficiently supply any amount of power from a few MW to the full capacity of 101 MW. For Alberta to reach its maximum renewable power capture potential, the Company believes it is likely the power grid will need to be stabilized with either batteries (which do not exist, as far as the Company is aware, in sufficient power output or storage duration yet) or simple cycle gas-fired power. The Company believes that the hardware selected for its first renewable project offers the best choice of current technologies to meet this very important need for the grid power system.

CCUS (Firm Renewable)

To the best of the Company's knowledge, nobody has adapted CO_2 capture equipment to a gas-fired intermittently operated, simple cycle power generator yet. Although CO_2 has been extracted in more challenging situations, the Company believes that the novelty of the application warrants a pilot test. Adding to the justification for the pilot test is the motivation to test new CO_2 solvents that have the potential to perform better than commercialized solvents in the following areas:

- Capital cost
- Operating cost
- Capture efficiency
- Toxicity
- Corrosivity
- Rate of contamination
- Energy required to desorb CO_2
- Intermittent operation

Kiwetinohk is aware of multiple recently developed solvents and has selected one to test on the first *Firm Renewable* project. Early-stage engineering is underway on the CCUS pilot.

***Integration Benefits* (*Firm Renewable*)**

Because of the expected high efficiency (relative to most simple cycle power generation), Kiwetinohk's *Firm Renewables* projects are expected to have attractive economics across a broad range of grid power prices. In Alberta, an auction system selects adequate supply at the highest price of the bids from generators that are tendered at or below the power price that provides adequate power to meet grid needs as they vary on an hourly basis. As mentioned previously in the section entitled, "Key Differentiator: Alberta's Resources, Markets and Infrastructure" Kiwetinohk expects that, as renewable wind and solar projects are added to the grid "right tail", high-power-price events will happen more frequently. The Company expects that its *Firm Renewable* plant(s) will be able to capture superior economics by operating intermittently and bidding in at attractive prices and achieve a higher than average overall operating price. However, if the industry builds multiple similar plants, the grid may be stabilized at the marginal cost of power from plants of this nature.

NGCC – Projects in Development

Kiwetinohk is in the early stages of planning two NGCC power plants. The plants are not as flexible and fast responding as *Firm Renewable* plants but, when operating at or near peak capacity, NGCC plants operate at significantly superior thermal efficiencies than *Firm Renewable* or other simple cycle gas-fired plants. This improved efficiency means less gas is consumed and less CO_2 is emitted per unit of electrical power delivered to the grid. For these reasons NGCCs are the preferred choice to provide reliable base load to the grid.

NGCCs have a lack of dispatchability in common with wind and solar power – *Firm Renewable* is superior among plant choices for dispatchability but is inferior to NGCC and renewables on emissions and efficiency. Both gas-fired systems compare favourably when compared with renewables on the basis of reliability. The Company believes that in the future large batteries can be coupled with solar and wind and reliably supply power even for extended periods of low output from the renewable sources, but the Company is not aware of batteries that could make renewable power adequately reliable. The Company believes that NGCCs are the best commercially proven alternative.

NGCC is a less carbon intensive source of electricity generation than the coal fired power plants this technology is replacing. Kiwetinohk expects that the NGCC technology it is pursuing is capable of delivering a CO_2 intensity that will be below 0.37, the Alberta Government's carbon tax reference level, which is better than the average of baseload plants in Alberta and significantly better than the coal fired electrical plants currently being phased out in Alberta. NGCC CO_2 intensity is expected to be approximately 0.39 tonne/MWh compared to current grid-connected, weighted-average emissions of approximately 0.54 tonne /MWh.[7]

[7] "AESO 2021 Long Term Outlook" (June 2021), online: *aeso* <https://www.aeso.ca/assets/Uploads/grid/lto/2021-Long-term-Outlook.pdf>.

Generator Type	Estimated Heat Rate, GJ/MWh	Estimated Carbon Intensity, t/MWh	Regulated "High-Performance Benchmark", t/MWh	Carbon Price (2022), $/t	Generator Cost of Carbon, $/MWh
Sub-Critical Coal	12.5	1.00	0.37	$50	$31.50
Coal-to-Gas Boiler Conversion	12.5	0.70	0.37	$50	$16.56
Simple-Cycle Gas	9.68	0.54	0.37	$50	$8.65
Combined-Cycle Gas	7.0	0.39	0.37	$50	$1.14

The Company is advancing, both at early stages, two NGCC opportunities and is in various stages of site identification and negotiation on these projects, which are currently at AESO stage 1.

CCUS/NGCC

Kiwetinohk believes that as Alberta's power grid transitions away from coal and towards renewables, it will also benefit from the addition of incremental NGCC power capacity, whose potential climate impact can be further mitigated by the addition of CCUS. Carbon capture is commonly used in what would appear to be more challenging situations but the dearth of commercial NGCCs with CCUS warrants monitoring developments until a system can be selected with low risk. Further, as is the case with *Firm Renewable*, recent development in solvents for CCUS use suggest that superior CCUS system performance may be achievable, and these technologies may warrant testing at a pilot scale with an NGCC plant. The potential benefits of the new solvent systems are the same as those cited for *Firm Renewable* except the energy required to regenerate the solvent and extract the CO_2 is different with an NGCC. NGCCs achieve part of their superior efficiency by extracting heat from the exhaust gas of the primary engine (in the case of NGCCs it is a gas turbine) by using in a second stage, a steam turbine that gets its energy from cooling the gas turbines' exhaust gas. While this makes the NGCC more efficient, it also means that there is less useable waste heat to aid in solvent regeneration. However, Kiwetinohk believes that there is potential to achieve better economic potential with newly developed solvents. Kiwetinohk's NGCC projects have not reached the decision point yet as to whether to install full capacity NGCC from the start or to pilot test and what solvent to pilot test.

Carbon Capture, Utilization and Storage – Projects

The Company does not have an engineered cost estimate for full carbon capture on any of its gas fired plants. The Company's preliminary estimates are in the range of 60 to 110% of the installed capital cost of *Firm Renewable* or NGCC without carbon capture.[8] In addition to the incremental capital cost, the most recent CCUS systems have an operating cost estimated to be USD$50-100 per tonne of CO_2 captured[9] with some emerging technologies approaching US$30 to US$40 per tonne of CO_2 captured[10]. Addition of CO_2 capture onto a powerplant reduces its thermal efficiency power output by 4-10%[11], which implies that

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[8] "Further Assessment of Emerging CO_2 Capture Technologies for the Power Sector and their Potential to Reduce Costs" (2 October 2019), online: *IEAGHG* < https://ieaghg.org/ccs-resources/blog/new-ieaghg-technical-report-2019-09-further-assessment-of-emerging-co2-capture-technologies-for-the-power-sector-and-their-potential-to-reduce-costs>.

[9] "Is carbon capture too expensive?" (17 February 2021), online: *IEA* <https://www.iea.org/commentaries/is-carbon-capture-too-expensive>.

[10] "Value of Emerging and Enabling Technologies in Reducing Costs, Risks & Timescales for CCS" (14 July 2020), online: *IEAGHG* <https://ieaghg.org/ccs-resources/blog/value-of-emerging-and-enabling-technologies-in-reducing-costs-risks-timescales-for-ccs>.

[11] Zhang, W, Sun, C, Snape, CE *et al.*, "Process simulations of post-combustion CO_2 capture for coal and natural gas-fired power plants using a polyethyleneimine/silica adsorbent" (2017), International Journal of Greenhouse Gas Control, Vol. 58, pp. 276-289.

a 60% efficient power plant would have thermal efficiency with CO_2 capture reduced to 50-54% depending on type of capture, site specifics, and configuration of the power plant.

Emerging technologies which may prove viable and are being monitored by Kiwetinohk include oxy-fueled power systems, which have the potential to greatly simplify CO_2 capture and some of which fit into the NGCC category, and gas turbines which can accept hydrogen as a fuel. Using blue hydrogen as a fuel pushes the carbon capture challenge to a gas-to-hydrogen plant such as an autothermal reformer between the gas field and the power station. Green hydrogen may fit into Kiwetinohk's long term future, mainly as a way to store energy from wind and solar if grid demand is weak in peak primary energy availability periods.

Hydrogen – Projects in Development

Kiwetinohk is also monitoring the relevant technologies and looking for investment opportunities in blue and green hydrogen projects. One project is an early stage of specific investigation and evaluation. It involves a potential industrial partner that is interested in reducing its natural gas use and is well positioned with its current infrastructure to convert to hydrogen use. For this project, the Company has also partnered with an established midstream infrastructure company that is also interested in pursuing hydrogen-based infrastructure investments. A non-binding Memorandum of Understanding has been executed and all three parties have dedicated significant in-kind resources to the advancement of the project. Area gas supply, CO_2 sequestration sites, and a facility location have all been identified. At this stage there are no significant commitments, and it is too early to confirm whether the project will go forward or to what degree if any Kiwetinohk will participate.

Other hydrogen initiatives, including the potential of new hydrogen-based electricity generation, electrolysis-based production of hydrogen, and hydrogen/natural gas blending markets are also being pursued, although at earlier stages of development.

Other Initiatives

Kiwetinohk's current efforts are focused on Alberta power generation. The Company is also actively investigating:

- natural gas development and production in British Columbia to supply power generation,
- power generation and/or hydrogen production in the Chicago area where the Company currently ships 120 mmcf/d of natural gas,
- hydrogen production in Alberta, and
- providing its products and services (electricity, natural gas, hydrogen, CO_2, and CO_2 sequestration) to other co-located business. These investigations involve a focus on gaining access to potential emerging markets with significant economic growth potential. In most cases these initiatives are early-stage strategic market development initiatives, aimed at enhancing profitability through business relationships that create a circular economy.

As described in more detail elsewhere in this AIF, Kiwetinohk views technology as having the ability to be both an opportunity and a threat to its business. The Company is monitoring emerging and competing power generation and hydrogen production technologies and competing primary energy sources. The business environment of rapidly evolving technology, regulation and stakeholder engagement means that the Company needs to remain nimble and aware.

Downstream Project Development and Financing Strategy

Kiwetinohk has designed a portfolio of potential renewable and gas-fired power projects for development that are expected to provide attractive returns and ultimately expected to deliver long-term, sustainable free cash flow. The Company has largely developed its own early-stage projects using internal funding and is currently engaged in upfront project planning, site selection, project permitting and front-end engineering and design for projects across its downstream portfolio. It is also evaluating acquisition of certain early-stage projects, generally renewables, under development by other developers requiring funding. Through internal technical/operational screening and economic analysis, the Company will select what it expects to be the top projects and progress towards a FID. As projects approach FID, sites and technology are selected, cost estimates are confirmed, marketing plans and contracts are determined, and investment risk is therefore significantly reduced.

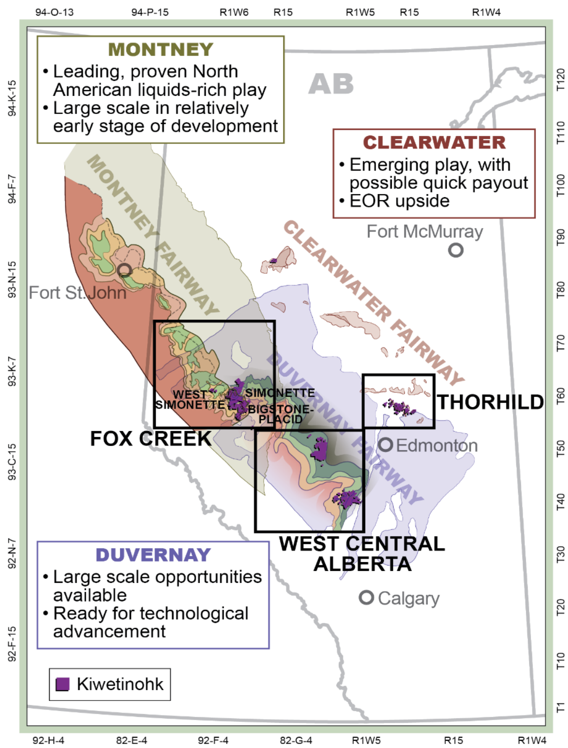
Kiwetinohk will be seeking optimal financing of its power projects using a combination of company and third party equity and debt to take its projects through construction. Due to the higher upfront risk involved in identifying and advancing downstream projects prior to FID, Kiwetinohk plans to pursue carried/promoted interests in exchange for the capital costs it will have incurred up to the FID date. In addition, Kiwetinohk will seek to co-invest with third party investors at project FID to achieve a targeted working interest level of up to 50% in each of its renewable projects. The Company may also look to access other financial supports, including Indigenous financing sources and export credit agency funding and guarantees. Certain new technology initiatives in the energy transition space may benefit from government grants for expenses ranging from feasibility studies through to project construction. Kiwetinohk intends to apply for grants in areas of interest, such as CCUS, as appropriate.

Kiwetinohk believes this investment strategy will allow it to achieve an attractive rate of return above its current cost of capital while providing material ownership interest and operational control of its downstream assets. The latter two points will be critical in providing a long-term sustainable return of capital employed to the Company.

While Kiwetinohk's current corporate structure has all of its business units under a single corporate entity, as the Company continues to advance its upstream integration and development of the downstream business, it may use focused limited partnerships to facilitate project financing. Shareholders of Kiwetinohk will continue to benefit from ownership of the fully integrated business.

Upstream Business Description

Kiwetinohk's upstream assets are primarily liquids-rich natural gas and crude oil producing and developing properties in the WCSB within the Canadian province of Alberta. As an energy transition company, the main objective of Kiwetinohk's upstream business is to provide natural gas for its anticipated gas-fired power and, eventually, for its anticipated hydrogen production business. Historically, liquids have been acquired by the Company in order to provide revenue diversity and production stability to the upstream business while the first power projects are built. The Company's operations are presently situated in three main regions: Fox Creek, Thorhild Radway and West Central Alberta.



The principal attributes of the Company's major oil and gas properties are as follows. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. The property descriptions contain references to proved developing producing, total proved and proved plus probable reserves, all as assigned in the 2021 Pro Forma Reserves Report.

	Gross Production (Third quarter 2021 daily average)						**Gross Reserves Proved Developed Producing**					
	NGL	**Crude Oil [1]**	**Condensate [4]**	**Conventional Natural Gas**	**Shale Gas**	**Total**	**NGL**	**Heavy Crude Oil**	**Tight Oil**	**Conventional Natural Gas**	**Shale Gas**	**NPV10[5]**
Property	bbl/d	bbl/d	bbl/d	mmcf/d	mmcf/d	boe/d	mmbbl	mmbbl	mmbbl	bcf	bcf	$mm
Fox Creek Region	1,766.4	10.7	4,225.0	3.1	47.8	14,483.4	16.4	--	--	4.4	109.1	431.0
Thorhild Region	-	39.3	-	-	-	39.3	--	--	--	--	--	2.9
West Central Alberta Region	47.4	291.5	41.8	-	0.9	535.7	0.2	--	0.4	--	2.2	14.7
Misc.	-	-	-	-	-	-	--	--	--	--	--	(0.6)
TOTAL	**1,813.9**	**341.5**	**4,266.8**	**3.1**	**48.7**	**15,058.4**	**16.6**	**0.1**	**0.4**	**4.4**	**111.3**	**447.9**

	Gross Reserves											
	Total Proved						Total Proved plus Probable					
	NGL	**Heavy Crude Oil**	**Tight Oil**	**Conventional Natural Gas**	**Shale Gas**	**NPV10[5]**	**NGL**	**Heavy Crude Oil**	**Tight Oil**	**Conventional Natural Gas**	**Shale Gas**	**NPV10[5]**
Property	mmbbl	mmbbl	mmbbl	bcf	bcf	$mm	mmbbl	mmbbl	mmbbl	bcf	bcf	$mm
Fox Creek Region	56.9	--	--	4.6	340.4	1,072.9	89	--	--	6.0	569.1	1,548.5
Thorhild Region	--	0.2	--	--	--	4.2	--	0.9	--	--	--	13.7
West Central Alberta Region	0.2	--	0.4	--	2.4	14.9	0.3	--	0.6	--	3.0	17.6
Misc.	--	--	--	--	--	(0.6)	--	--	--	--	--	(0.6)
TOTAL[1]	**57.1**	**0.2**	**0.4**	**4.6**	**342.8**	**1,091.4**	**89.3**	**0.9**	**0.6**	**6.0**	**572.2**	**1,579.2**

Notes:

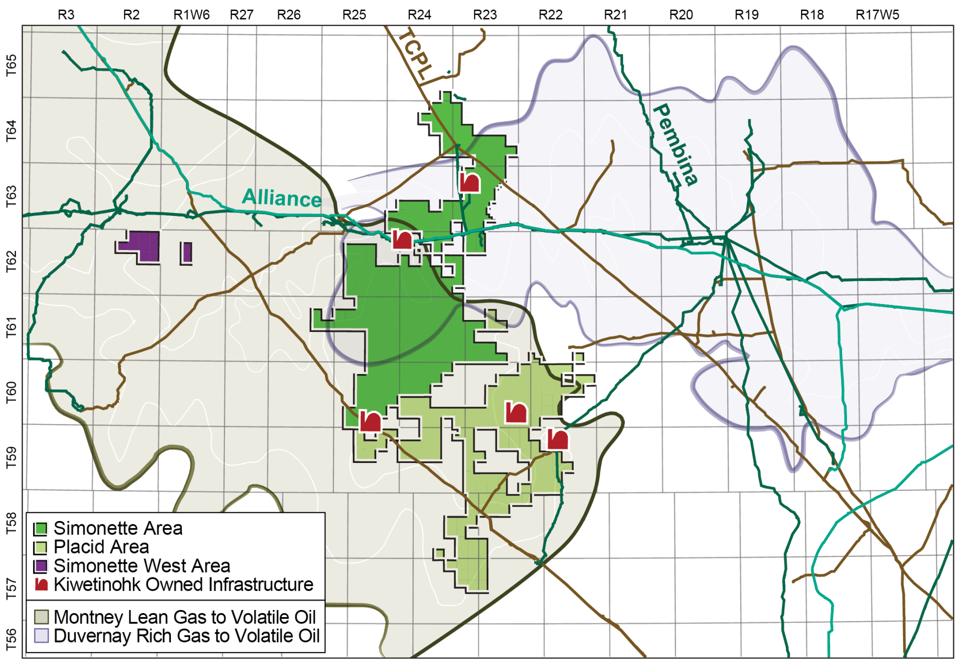
(1) Includes light and medium crude oil and heavy crude oil.
(2) Numbers may not add due to rounding.
(3) All reserves estimates are from the 2021 Pro Forma Reserves Report with an effective date of July 1, 2021.
(4) For NI 51-101 purposes, condensate production is included with NGL production, resulting in Q3 2021 NGL production of 6,074 bbl/d.
(5) NPV10 columns are before taxes.

	Landholdings[1]		Asset Retirement Obligations[2][3]		
			Inactive	Active	Future
	Undeveloped	**Developed**	**Undiscounted**	**Undiscounted**	**Undiscounted**
Property	Net Acres	Net Acres	$mm	$mm	$mm
Fox Creek Region[4]	165,304	68,469	12.1	53.6	143.4
Thorhild Region	53,536	480	1.2	0.1	2.4
West Central Alberta Region	189,180	8,800	7.1	3.8	10.9
Misc.	69,643	14,279	9.1	0.9	10.0
TOTAL[4]	**477,663**	**92,028**	**29.5**	**58.4**	**166.7**

Notes:

(1) Landholdings shown above are net acres in the Montney, Duvernay and/or Clearwater formations, among others. Acreage position is expressed as at July 1, 2021. Acreage is counted as developed when a well is located within a unit or traditional well spacing unit. In the case of unconventional wells lacking traditional spacing units, acreage has been counted as developed for each quarter section through which a wellbore passes in the case of an oil well, and each section through which a wellbore passes in the case of a gas well. All other acreage is counted as undeveloped. Where prospective formations overlap on the same leases (Duvernay and Montney lands do overlap in the Simonette block), the acreage has not been double counted. A significant portion of the misc. undeveloped acreage will be expiring over the next year.
(2) "Asset Retirement Obligations" is generally defined as costs associated with the clean up and restoration of the physical environment with respect to activities either inherited or undertaken by Kiwetinohk. These include but are not limited to well, facility and pipeline abandonment, remediation of spills and other negative environmental effects and the final restoration of sites associated with the Company's activities, including leases, oilfield waste sites, camps, roads, ponds and other physical assets.
(3) In connection with its operations, Kiwetinohk will incur abandonment, dismantling, reclamation and remediation costs for surface leases, wells, facilities and pipelines. Kiwetinohk budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its oil and gas assets. Kiwetinohk uses guidance from the AER and consultation with an independent third-party engineering firm to validate the estimates of such liabilities. Approximately 66% of Kiwetinohk's decommissioning liabilities on its financial statements are associated with active properties that have production and attributable reserves. There is approximately $29 million of net inactive abandonment and reclamation costs associated with operated and non-operated inactive wells, facilities and pipelines where there is no active operations or attributed reserves. Kiwetinohk is currently working on an abandonment program to proactively manage and reduce the inactive decommissioning liabilities over the next five to six years.
(4) Numbers may not add due to rounding.

Fox Creek



The Fox Creek region operations (approximately 140 km southeast of Grande Prairie, Alberta) contain the Company's most important assets in the Simonette and Placid areas shown on the map. Most of Kiwetinohk's property in this region was acquired through two major transactions executed in 2020 and 2021: 1) the Distinction Investments and subsequent Business Combination and 2) the Simonette Acquisition. Continued profitable consolidation in this region is a corporate objective.

The Fox Creek assets are primarily focused on the liquids-rich development of the Montney and Duvernay formations. KEC has targeted accumulation of natural gas that is rich in liquids because associated liquids production generally enhances and stabilizes the economics of natural gas development. Gross production in 2021 Q3 was 15,058 boe/d. The Company believes both areas have capacity to process and ship significantly more production without major facility capital spending as evidenced by gross production levels at Placid (and nearby working interest lands) of 6,463 boe/d and at Simonette (and nearby working interest lands) of 8,020 boe/d.[12]

Management believes the Fox Creek assets are ideally suited for current development, and to potentially supply natural gas feedstock for Kiwetinohk's future gas-fired power projects for the following reasons:

- Proven development opportunities in the liquids-rich Montney and Duvernay formations
- Significant existing processing plant and gathering system infrastructure allows for growth with lower additional infrastructure spending than a completely undeveloped land situation would require
- High liquids content compared to most natural gas focused peers contributes to high netback production
- Access to multiple egress options with secured contracts pipeline transportation contracts
- Potential consolidation opportunities in the region

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[12] These numbers were derived from publicly available production statistics, applying the land ownership situation as it was at end Q2 2021.

Development in the Simonette area has primarily been focused on the liquids-rich Duvernay formation. Production from the asset averaged 8,020 boe/d in Q3 2021 (42% liquids) comprised of 813 boe/d NGL, 2,595 boe/d condensate, and 28 mmcf/d conventional natural gas.

In the Placid area, just south of Simonette, the liquids-rich Montney is the primary formation for development. Production from the asset averaged 6,463 boe/d in Q3 2021 (40% liquids) comprised of 954 boe/d NGL, 11 boe/d tight oil, 1,630 boe/d condensate, 20 mmcf/d shale gas and 3 mmcf/d conventional natural gas.

The three most recent development wells on Kiwetinohk's Fox Creek lands were Placid Montney horizontal wells drilled and completed by Delphi in the months before it went into restructuring under the CCAA. These wells demonstrated initial production (sales) in the first 90 producing days averaging approximately 2.8 mmcf/d of natural gas and 684 bbl/d of condensate. These three wells generally out-performed prior wells drilled by Delphi on these lands. The improved performance is attributed to their high-pressure location (to the west of most of Delphi's previous wells) and due to the drilling and completion methods that KEC deployed. In its evaluation under the 2021 Pro Forma Reserves Report, McDaniel assigns 32 remaining Montney horizontal drilling locations with total proved plus probable status.

The Company also plans to add future production and recovery from other areas and (possibly) intervals within the Montney formation at its Fox Creek lands. Presently, in the Fox Creek area the Company is focused on the uppermost of the benches within the Montney in the Placid area. There are a few wells in the Montney in the Simonette area. As outlined in the 2021 Pro Forma Reserves Report, McDaniel assigned total proved plus probable reserves to approximately 20% of the Simonette assets, 78,720 acres of Montney zone rights. Recently, the Company cored a vertical well to evaluate a lower porosity bench that pervades the Placid region. As to long term potential, the Company is intrigued by the Montney's value potential in much of the Simonette land and the lower porosity bench in Placid. The Company expects to need a few wells in the sparsely drilled areas and in the deeper bench in order to determine and prove the commercial potential. Some of the Company's Montney land, upon initial examination, appears to have potential for cyclic gas injection for enhanced condensate and/ or oil recovery. The very high pressure of the Duvernay gas resource makes the prospect of cyclic gas enhanced recovery more intriguing in that new, leaner Duvernay wells could be used to charge the Montney with gas, potentially, with much less processing and compression expense than the Company would expect for areas where high-pressured natural gas bearing Duvernay does not underly the Montney.

The Company believes the Duvernay and Montney properties that the Company possesses in Fox Creek are suited to the Company's upstream skill set in multi-stage fractured horizontal wells. Several members of the Kiwetinohk upstream team possess relevant expertise acquired at nearby lands previously operated by Seven Generations (which was recently acquired by ARC Resources), a major Montney developer. The previous owner of the producing Duvernay wells in the Fox Creek region developed the land by adding multi-well pads in a continuous orderly development. The well design evolved over years of development by changing parameters such as well spacing, fracture spacing and fracture size (as measured by tonnes of proppant), among other parameters. In some areas, wells remained unbounded on at least one side for a few years. In general, the Company believes that these wells demonstrate higher projected ultimate recovery than their confined neighbors. All of these observations suggest a potential for improved profitability from continuing to advance well designs and planning for wider well spacing. The Company is currently drilling two Duvernay horizontal wells from an existing pad in the Simonette area that are expected to be onstream in early 2022. In its evaluation under the 2021 Pro Forma Reserves Report, McDaniel assigns 61 remaining Duvernay horizontal drilling locations with total proved plus probable status.

For Fox Creek, the Company anticipates significant upside recovery and value potential from technology adaptation and extension, specifically:

- Optimizing layout and well design:

    - lateral spacing
    - lateral length
    - tubular diameters
    - frac spacing
    - perforation clusters per frac
    - frac slurry volume
    - frac fluid including proven fluids and methane foam
    - slurry pump rate
    - proppant specification
    - slurry proppant concentration
- Electric frac spreads
- Artificial lift system selection and adaptation and operation optimization
- Cyclic gas injection enhanced liquids recovery

Many of these value optimization opportunities are expected to increase resource recovery and may also deliver improved environmental performance including reduced GHG emissions, reduced surface land disturbance, reduced saltwater production and reduced fresh water use.

The Company has a 100% working interest in extensive, well-designed and well-maintained surface facilities. There is also an extensive gas gathering system converging on two gas plants with a combined sales gas capacity of 96.5 mmcf/d and a combined natural gas liquids (excluding condensate) capacity of 3,650 bbl/d. A condensate stabilization plant adds 14,350 bbl/d of condensate capacity. The facilities include a fresh-water distribution and storage system connected to the Company-owned water source wells and to a competitor-owned intake on the Little Smoky River. The gas plants are currently connected to the Alliance Pipeline and the Company has a take or pay contract for 90.3 mmcf/d capacity of rich gas from Simonette on the Alliance system (in addition to 29.7 mmcf/d capacity on Alliance (from Distinction) in the Placid area). Access to alternate transmission pipelines (TC Energy for gas and Pembina for liquids) is also available in the region.

The Company's gathering and processing infrastructure in the Placid area is jointly owned with other developers. Working interests are generally not consistent between lands, wells and facilities although the Company generally has the largest working interest in any of its lands. There are numerous gas plants in the region that are fed by a vast network of sweet and sour gas gathering lines, allowing the Company alternatives for optimizing and increasing its processing capacity as appropriate for its business plan.

The Company's West Simonette property consists of twelve sections of Crown land with Montney rights that had been delineated, but not production tested, by a previous owner. The Company was able to acquire the delineation well which is cased and suitable for adding a producing horizontal lateral. Per the 2021 Pro Forma Reserves Report, McDaniel attributes 16 horizontal drilling locations to the lands in its total proved plus probable evaluation.

Indicative individual well economics for the Fox Creek Region from McDaniel's proved plus probable well performance forecasts in the 2021 Pro Forma Reserves Report were averaged by Kiwetinohk according to the planned drilling in 2022 and are tabulated below by formation:

	DUVERNAY	MONTNEY
IRR before tax	214	96
PIR15 before tax	1.21	0.82
Break-even 15% IRR WTI ($US/bbl) @ AECO = $CAD 3.25/ mmBtu	19.58	31.13
Break-even 15% IRR AECO ($CAD/mmBtu) @ WTI = 53.50 $US/bbl	-3.41	-0.11

The economics tabulated above used the well designs and production forecasts prepared by McDaniel in connection with the 2021 Pro Forma Reserves Report. "IRR" is a measure of return used to compare the profitability of an investment and represents a discount rate at which the net present value of costs equals the net present value of the benefits and "PIR 15" refers to the ratio required to earn a 15% return on an investment, calculated as expected profits divided by initial investment. The higher an investments rate of return, the more desirable the investment. The above assumes a 12 (Duvernay) and 6 (Montney) well program in 2022. Operating costs were forecast at $14,000.00/well/month fixed and variable costs of $0.12/mcf (sales) and $2.90/barrel of fluid (NGLs, water or condensate), and on average $10,450.00/well/month fixed and variable costs of $1.48 /mcf (sales) and $1.88/barrel of fluid (NGLs, water or condensate) for the Montney wells. Economics presented are based on a foreign exchange rate of 0.801 $US/$CAD; WTI price of US $53.50/ bbl and AECO gas price of CAD $3.25/ mmBtu.

Thorhild Radway

Thorhild Radway was acquired to potentially act as a production stabilizer. The property is situated approximately 70 km north of Edmonton. Low-permeability reservoirs developed with multi-staged fractures of horizontal laterals, such as the Montney and Duvernay formations near Fox Creek, often display steep declines from initial productivity. If a development is still in the growth stage, added production from a single drilling campaign can be a significant fraction of total production. This situation creates an undesirable volatility in the production profile of the total property. With that in mind, Kiwetinohk acquired land in the Thorhild Radway area prone to medium-heavy oil that the industry is developing with unfractured multi-lateral wells. The wells cost about 10% of the capital cost of a Fox Creek rich gas well but their production profile is flatter. The Company hopes to find crude oil and develop the play between cycles of drilling at Fox Creek, with the expectation that clusters of the medium-heavy oil wells will somewhat fill gaps between the peaks of Montney and Duvernay production additions.

The Company's property in the Thorhild Radway Region includes approximately 88 net sections of acreage in the Clearwater fairway that is effectively a southern extension to the central portion of the main heavy oil play. In recent years, pioneers in the play have shown that wells with multiple, unfracced, open hole multilaterals can deliver excellent economics. Approximately 46 sections of land have been mapped internally to indicate Clearwater drilling potential. The Thorhild Radway land accumulation was initiated by an attractive transaction through which the Company acquired 60 gross (57 net) sections of land from a receivership by undertaking to abandon and reclaim approximately 10 wells and pay approximately $1 million.

Since the initial acquisition, the Company has added land and one producing multi-lateral well (confirming the presence of productive oil from the Clearwater formation) through private transactions and Alberta Government Crown land sales. In Q3 2021 this acquired well was producing approximately 40 bbl/d of heavy oil.

The Company recently drilled its first multi-lateral horizontal well in the area and put it on production in June 2021. This initial well encountered very heavy, high-viscosity crude oil leading to very poor production rates. Although disappointing, wide variation in crude oil properties is not uncommon in the Clearwater play. Kiwetinohk drilled and cut core in a recent vertical test well to assess oil and reservoir characteristics in a different part of the play.

Subject to encouraging results, Kiwetinohk may continue to test and delineate the play and potentially other geological zones in the area.

West Central Alberta

The Company's assets in the West Central Alberta Duvernay formation were acquired in a series of transactions: a farm-in on a competitor's holdings in 2018, Alberta Government Crown land sales, private transactions and the Simonette Acquisition earlier in 2021. Most of the land lies between the towns of Entwistle and Rimbey, centered approximately 110 km southwest of Edmonton. The Duvernay formation in the region consists of a hydrocarbon shale source rock interbedded with limestone stringers, some of which the Company believes are thick and continuous enough to impair hydraulic fracture height growth and / or production. The hydrocarbon saturated shale thickness varies up to more than 30 metres in some parts of the Company's land but the accessible thickness with any hydraulic fracture stimulation may be much thinner. The Company sees the West Central Alberta Duvernay zone as a significant future natural gas resource that will take several wells in each sub-region with similar geology to determine an optimal well design.

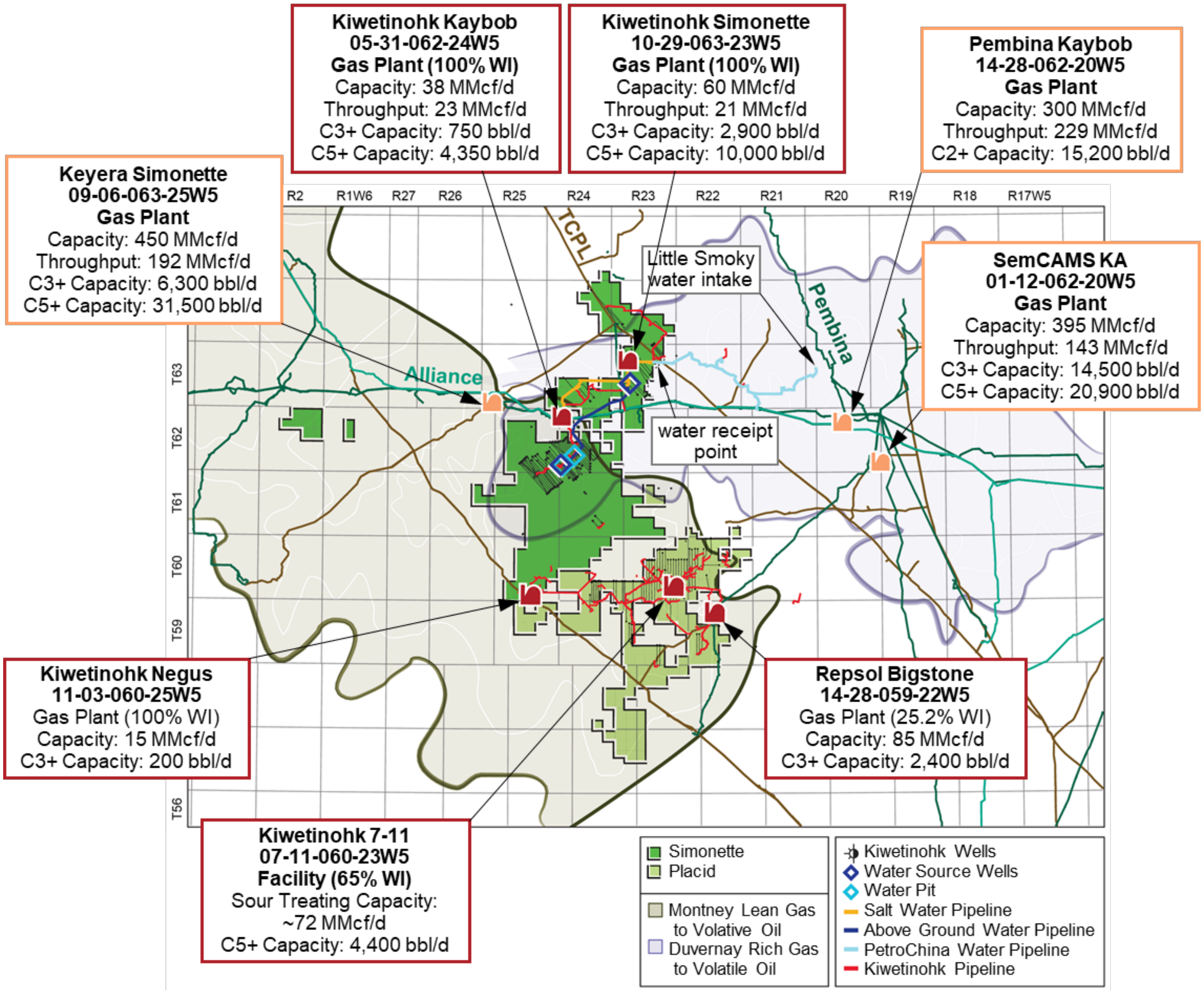
While the geology and production characteristics of the West Central Alberta Duvernay are not attractive on a relative basis to the Company's other upstream opportunities at Fox Creek, the formation represents a potentially large natural gas supply in an attractive region for power and hydrogen development. Much of the resource lies in a region that has excellent characteristics for natural gas-fired power generation, including:

- power grid capacity,
- reservoirs suited to CO_2 EOR,
- formations suited to CO_2 sequestration,
- skilled tradesman, and
- extensive midstream natural gas pipeline capacity.

The Company has chosen to defer commercializing the West Central Alberta Duvernay but to continue pursuing opportunities to engage in power and hydrogen production in the region. In the short term, the Company plans to monitor technical developments arising from competitor activity but to rely on more economic sources of natural gas.

Midstream, Marketing and Transportation Arrangements

The Company's Fox Creek natural gas, natural gas liquids, condensate and crude oil assets are located near strategic transportation and processing infrastructure for both liquids and natural gas. The significant amounts of Company-owned infrastructure with ample spare capacity and midstream, marketing and transportation arrangements provide more than sufficient capacity for the future growth of production and are described below.



Alliance Pipeline

The Alliance Pipeline is a transcontinental pipeline network that carries liquids-rich natural gas from British Columbia and Alberta to the Chicago, Illinois area, where liquids contained therein are extracted, fractionated and sold into the U.S. Midwest refining and petrochemical market, and remaining natural gas is sold into the Chicago area marketplace and interconnecting markets. The Alliance Pipeline is connected to the Company's two Simonette gas plants. Kiwetinohk currently has a contract to deliver 120 MMcf/d of natural gas into the Alliance pipeline for the greater Chicago market until October 31, 2025. Kiwetinohk meets the contract obligation through the delivery of gas that it produces and gas that it acquires from competitors. The Company is also looking at alternative markets for its produced gas and at sources of gas to fuel planned power generation projects.

Aux Sable

Aux Sable owns and operates one of the largest NGL extraction and fractionation facilities in North America, located in Channahon, Illinois at the terminus of the Alliance Pipeline. The Company's natural gas marketing contracts associated with the Simonette-Alliance Pipeline transportation contracts currently include a rich gas premium agreement with Aux Sable. The rich gas premium agreement provides the

Company with deep cut NGL revenues based on liquids recovered by Aux Sable at the NGL extraction and fractionation facilities operated by Aux Sable at values based on the Conway, Kansas market.

TC Energy

The Nova Gas Transmission Ltd. ("**NGTL**") system receives, transports and delivers natural gas within Alberta and connects with the 14,114 km (8,770 mile) pipeline system that is owned and operated by TC Energy Corporation and its affiliates, which carries natural gas from the WCSB to Ontario and beyond, the Foothills pipeline system and other third-party pipelines. The Company acquired 0.3 mmcf/d of NGTL service effective May 1, 2021, which expires in mid-2023, and a separate and independent NGTL contract for 20.1 mmcf/d associated with its Placid region expiring on March 31, 2026.

Pembina

This pipeline system and related facilities (the "**Pembina Peace Pipeline**") is owned and operated by Pembina Pipeline Corporation ("**Pembina**") and delivers crude oil, condensate, propane mix and ethane mix from northeastern British Columbia and northwestern Alberta to local markets in Alberta. The Pembina Peace Pipeline is connected via direct sales at the Company's two Simonette gas plants, as well as via other third party operated plants where the Company's liquids are produced. Kiwetinohk has agreements with Pembina for transportation of oil, condensate and NGL on the Pembina Peace Pipeline with delivery points to Fort Saskatchewan for further processing (propane plus, C3+) and sale, or to Edmonton (condensate, C5+) for sale. These agreements allow the Company to transport all existing production of condensate and NGL with the potential to increase capacity if necessary.

Field Condensate Handling

The Company has an agreement with a midstream company who has built a condensate pipeline from the Montney assets to a full-service terminal at Fox Creek where the fluids are sold onto Pembina's pipeline system in the area. No take or pay commitments are associated with the pipeline project, but the Company has a production dedication area for the project.

Midstream Contracts

The Company is a party to the contracts described below (general descriptions are provided but details have been withheld in some cases due to competitive or confidentiality agreement reasons):

Counter party	**Purpose**	**Daily volume, Take-or-pay obligation, cost or revenue**	**Expires**
Alliance	Transportation from Simonette plants to Chicago	90.3 mmcf/d	Oct 31, 2025
Alliance	Transportation from Placid to Chicago	29.687 mmcf/d	Oct 31, 2025
NGTL	Transportation from Placid plants to AECO	20.1 mmcf/d	Mar 31, 2026
NGTL	Transportation from Simonette to AECO	1.1 mmcf/d	Mar 31, 2023
Pembina	NGL Transportation from Simonette to Fort Saskatchewan	--(1)	--(1)
Pembina	NGL Fractionation in Fort Saskatchewan	--(1)	--(1)
Aux Sable	Rich Gas Premium	90.3 mmcf/d (matches Alliance firm capacity)	Oct 31, 2023

Note:
(1) Details withheld due to confidentiality constraints.

In addition to the above, the Company has acquired in excess of 90,000 GJ/d of gas supply from several producers in 2022, allowing Kiwetinohk to fully utilize its Alliance capacity.

People

Kiwetinohk's Energy Transition Leadership and Technical Team

Kiwetinohk benefits from the leadership and extensive energy industry, markets, policy and project development experience of its Board and its management team led by Kevin Brown as Board Chairman and Pat Carlson as Chief Executive Officer. Mr. Brown is Co-Chair and Director of ARC Financial Corp. which acts as advisor to the funds that are Kiwetinohk's largest shareholder and own approximately 63% of the Company following the Business Combination. Please see below for a brief overview of Mr. Carlson's experience and success in the energy industry.

In addition to the expertise of Mr. Brown and Mr. Carlson, Kiwetinohk is managed by a ten-member, senior executive team. Reporting to that team are functional group leaders who have, within their career span, proven excellence in their fields of practice. The Company looks to these functional group leaders to collaborate to differentiate Kiwetinohk from its competition using:

- full cycle planning and risk and opportunity analysis
- technology
- operational effectiveness
- stakeholder engagement and
- high-grading.

Leading Kiwetinohk's operations, project and ongoing engagement with stakeholders, the Company's strong and experienced executive and technical team consists of the following individuals:

Name and Title	Overview of Relevant Experience
Patrick Carlson (1) *Chief Executive Officer*	Chief Executive Officer of Kiwetinohk since the inception of Kiwetinohk Resources Corp., Pat Carlson, previously, co-founded and led four successful Alberta-based energy companies, each sponsored by ARC, including, most recently, Seven Generations Energy Ltd. (from which he retired as Chief Executive Officer in June 2017). Pat holds a B.Sc. in chemical engineering from The University of Calgary. Pat's experience in the energy industry is broad from conventional oil and gas, to heavy oil, to oil sands, to shale oil and gas. Pat has worked in most facets of engineering engagement by the petroleum industry: reservoir engineering including modeling, enhanced recovery, evaluations and mergers and acquisitions, drilling, completions and production. Pat has received numerous professional and industry awards: • Schulich School of Engineering, Distinguished Alumni Award for Leadership, 2019 • Canadian Petroleum Hall of Fame, Inductee, 2018 • Alberta Chamber of Resources, Resource Leadership Award, 2017 • Grande Prairie Chamber of Commerce, Business Citizen of the Year, 2016 • Schulich School of Engineering, Canadian Engineering Leadership Award, 2013 • Lloydminster Oilfield Technical Society, Oilman of the Year 2008 • Twice honoured by the Ernst & Young Entrepreneur of the Year Awards, as a Regional sector finalist for North American Oil Sands and as Regional sector winner for Seven Generations Energy Ltd. Pat has been active in professional organizations that enable their members to better serve the energy industry and society. Pat holds the ICD.D corporate director certification and currently serves as an executive on the Calgary Chapter of the Institute of Corporate Directors. Previously, Pat served on the advisory board of University of Calgary's Schulich School of Engineering and he was co-founder of the

Lloydminster and District Heavy Oil Section of the Petroleum Society of The Canadian Institute of Mining and Metallurgy which has since merged with the Dallas-based, Society of Petroleum Engineers.

Aside from his own companies Pat has been a director of several private companies. A passionate environmentalist, Pat served as co-chairman of the Canadian Association of Petroleum Producers' Environmental Research Advisory Council, focusing on climate change in the early 1990s. More recently Pat and his wife, Connie, joined with the Pembina Institute to sponsor the Alberta Narratives Project (a climate change education and communication program for the Alberta public). The couple also have been major sponsors of the Alberta Water Portal (a website that provides the public with education, research and news about water).

Janet Annesley (1)
Chief Sustainability Officer

Appointed Kiwetinohk's Chief Sustainability Officer in September 2021, Janet Annesley brings a breadth of communications, stakeholder engagement, policy and sustainability experience to her role.

A former executive at Shell Canada and Husky Energy Inc., and a former chief of staff to Canada's Minister of Natural Resources, Janet has developed and implemented corporate and government policies and programs on stakeholder engagement, climate change, Indigenous reconciliation, and diversity and inclusion. Janet worked as part of several leadership teams to deliver major projects, including carbon capture and storage.

Janet holds an MBA from Queen's University. She was named to The Hill Times Top 100 in Power and Influence List in 2017 and is a Public Policy Forum Fellow. An award-winning, accredited business communicator, she sits on the advisory board for Clean Prosperity and on the boards of the Southern Alberta Institute of Technology and the City of Calgary Green Line LRT Project.

Mike Backus (1)
Chief Operating Officer, Upstream

Mike Backus is the current Upstream Chief Operating Officer for Kiwetinohk Energy Corp (KEC). He has over 25 years of experience in a variety of engineering, operational, finance and executive roles. Prior to joining KEC, Mike was a member of the executive team at Painted Pony Energy where he was responsible for the Development and Operations of the company prior to its corporate sale. Most of his career was spent with Nexen Inc. (now CNOOC International) where he was most recently the VP Operations for Canada and the UK North Sea businesses. Mike has held various positions during his career, including working both conventional and unconventional Canadian gas and power assets, oilsands, offshore North Sea, Middle East and West Africa. His career has spanned drilling and completions engineering, reservoir engineering and development, project management and planning, investor relations, corporate finance/treasury, operations, Health, Safety and Environment, and executive leadership. Mike holds both a Bachelor of Commerce degree in Accounting and a Bachelor of Science degree in Mechanical Engineering, both from the University of Saskatchewan. He is a registered Professional Engineering in Alberta. Mike has also held various industry association roles in both Canada and the UK. Aside from his industry career, Mike has and currently holds director positions with a private company and a charitable organization.

Jakub Brogowski (1)
Chief Financial Officer

Mr. Jakub Brogowski is Kiwetinohk's Chief Financial Officer. Jakub joined Kiwetinohk in December 2018 after a lengthy career in investment banking which included energy experience in Canada, the United Kingdom, Europe, the Middle East and Asia. From 2003 to 2018, Jakub worked for two global investment banks in both Calgary and London analyzing, evaluating and advising on a wide range of corporate finance activities including private/public equity, debt and hybrid capital raising, project finance, mergers and acquisitions and strategy. During this time he completed over 50 advisory and financing transactions with a total value of approximately $46 billion. Jakub was also named in the European Financial News Top 40 Under 40 Investment Banking Advisory list for 2012. He graduated from the University of Calgary, Haskayne School of Business in 2002 with a Bachelor of Commerce (with distinction), majoring in finance.

Mike Hantzsch (1)
Senior Vice President, Midstream and Market Development

Mike Hantzsch is a professional engineer with over 40 years of management, business and technical experience, predominantly in the midstream segment of the petroleum business: gathering, processing, marketing and transportation.

Mike Hantzsch was Senior Vice President, Canada of Meritage Midstream ULC and was responsible for all aspects of building and running a Canadian midstream business, including strategic planning, business development, mergers and acquisitions, organizational management, financial planning/performance and operations. Prior to joining Meritage Midstream, Mike was Vice President, Oil Sands & Heavy Oil with Pembina Pipeline Corporation. In that role he was responsible for executive oversight of Pembina's Oil Sands & Heavy Oil Business Unit which operates approximately 1,650 km of pipelines and has approximately 880,000 bpd of capacity under long-term extendible contracts. Mike retired from Pembina Pipeline Corporation on December 31, 2014.

Prior to joining Pembina, Mike was Vice President of Business Development at Provident Energy Ltd. and led the $750 million acquisition of EnCana's NGL business, the largest acquisition in the company's history. He was also responsible for the purchase of Dow's Hydrocarbon Storage and Distribution Facility in Corunna, Ontario. More recently, Mike was a deal team member and main company contact during the sale of Provident Energy to Pembina Pipeline for $3.2 billion, which closed in April 2012.

Previously, Mike spent several years in Business Development functions with Williams Energy, identifying and implementing acquisition and investment opportunities, and playing a key role in the purchase of TransCanada Midstream's NGL business. Earlier in his career, Mike worked at MAPCO Canada, Novagas Clearinghouse and started his career with Shell Canada Limited in 1978.

Mike graduated from the University of Toronto in 1978 with a B.A.Sc. degree in chemical engineering and has been a registered professional engineer in Alberta since 1980. He served as a director of Williams Energy (Canada), Inc., Williams Natural Gas Liquids Canada, Inc., Pan-Alberta Resources Inc. and 898389 Alberta Ltd. from September 2000 through September 2002. Mike served as an officer of Pembina Pipeline Corporation and its affiliate Oil Sands subsidiary companies from April 2012 through December 2014 and served as a director of Meritage Midstream Services III, LP and as an officer and director of Meritage Midstream ULC from July 2015 through January 2017. He is currently an officer of Kiwetinohk Energy Corp. and the company representative to the Explorers and Producers Association of Canada.

Sue Kuethe [1]
Executive VP, Land and Community Inclusion

Sue Kuethe joined Kiwetinohk Resources Corp. in March of 2018 as its Executive VP, Land and Community Inclusion. For 21 years, until mid-2015, Sue was a Senior Executive (principal function Vice-President, Land and Community Affairs) with various Koch Industries Inc.'s subsidiaries in Canada, the US and internationally. During her tenure at Koch, she had responsibility for leading aboriginal and community affairs, negotiations and land related business activities. In that capacity Sue negotiated and closed transactions exceeding one billion dollars, and managed land department activities in Canada and the United States for an acreage base of over 2 million acres. Sue and her group were responsible for building successful relationships with over 20 different First Nations and Metis Communities. Prior to working for Koch, Sue held a variety of positions in the oil and gas industry in the United States and Canada, including land positions with Alberta Energy Company, and General Manager of a public junior oil and gas company located in Denver, Colorado.

Sue graduated from the University of Colorado with a Bachelor of Arts (Anthropology) in 1983. She is a member of the Canadian Association of Petroleum Landmen (P. Land) and the Association of International Petroleum Negotiators. Sue was elected to the Board of Directors of the Canadian Association of Petroleum Landmen in 2004 where she served as Director of Professionalism. Sue was selected by Leibham & Company, as one of Calgary's Leading Women in 2004. In 2014, she received Koch Industries Environment Health and Safety Award for Building Long Term Relationships with First Nations in Canada. This award was the first of its type ever granted by Koch Industries. She acted as an Advisor to The Social License Consortium and has been affiliated with the University of Houston's Global Energy, Development & Sustainability Program.

Sue has spoken at multiple recent events including:

- Moderated the University of Calgary's 2016 Canadian Association of Environmental Law Society's panel on Aboriginal Peoples, Industry and the Environment.
- Member of the Conflict Resolution Panel of the Second Annual Mexican-Canadian Seminar for Consultation and Participation of Indigenous Peoples in the Development of Energy Projects held in Mexico City in 2017.
- Moderated the Connections to Indigenous Communities Panel for the 2017 International Petroleum Show's Indigenous Conference on Energy & Mining "Empowering Connections."
- The Kenyan Delegation to Alberta in 2018, speaking on Engaging Indigenous Populations, the Alberta Experience.
- GeoConvention 2021, speaking in September 2021 at the First Nations Fireside Chat.

As well, in 2016, Sue led the indigenous engagement portion of Social License Consortium's workshop for Mexican employees of an international industrial corporation in Pachuca, Mexico.

Ms. Kuethe has been a mentor in the master's degree Sustainable Energy Development program through the University of Calgary's Professional Mentorship Program. Sue volunteered in remote areas of Nicaragua with Namlo International, a charity founded to help with children's education and with women's skill development.

Kurt Molnar [1]
Senior Vice President, Business Development

Kurt joined Kiwetinohk two years ago as SVP, Business Development. Kurt brought with him a 30+ year track record for excellence in all facets of energy finance, most recently being independently ranked as among the top three equity analysts in his field for the five consecutive years prior to his joining Kiwetinohk. Kurt's highly diversified background in energy finance includes being a prior founder of a successful private oil and gas company, a corporate lender to the oil and gas industry, an institutional equity salesperson specializing in energy equities and as the leader of an energy investment banking group. This diversity of background, with both banks and boutiques, is particularly valuable today given the change underway in energy finance.

Throughout Kurt's equity research career, he was routinely independently ranked among the best of his equity peers for identifying emerging new trends, opportunities or threats in energy markets. Kurt's vast experience with debt and equity financing, and analyzing, energy companies/global energy markets, provides valuable experience and context in a Canadian energy industry that is currently undergoing widespread change and consolidation. Kurt holds a Bachelor of Commerce degree from the University of Calgary, with a major in Finance. Throughout his career he has been active in the community and was a founding member of the capital committee for fundraising for the Southern Alberta Ronald McDonald House built in Calgary.

At Kiwetinohk, Kurt coordinates the merger and acquisition process for both upstream and downstream assets. Additionally, Kurt's strong, general business skills have been called upon to lead the Power team while the Company actively pursues the recruitment of a Division President.

Lisa Wong (1)
Senior Vice President, Business Systems

Lisa Wong is a 30-year veteran of the oil and gas industry, with experience in Finance, Accounting and Organizational Effectiveness.

After graduating from University of Calgary with a Bachelor of Commerce degree in Finance, her career began as a Financial Analyst at Murphy Oil, Canadian Division and continued in progressively senior roles at various Oil and Gas companies. Starting in 1999 through to 2011, she was part of various management teams that founded and successfully sold start-up private equity companies Passage Energy Inc., Krang Energy Inc., Breton Energy Inc., and Caltex Energy Ltd.

While at Nexen Inc. from 2012 to 2015, Lisa progressed to Manager, Production and Royalty Reporting and Compliance, North American Operations. She was part of the integration team that worked with CNOOC International during their Nexen Inc. acquisition where she utilized her language skills and knowledge and respect of the Chinese culture to assist in the integration.

At Kiwetinohk, Lisa manages communications, information and records, human resources, office space and oversees the administrative support team. Lisa teaches and coaches customized management systems that the Company uses to coordinate projects among multiple functional groups. Lisa coordinates many of the Company's formal team building activities.

Farid Shirkavand (1)
Vice President

Farid started his career working on offshore drilling projects as a drilling engineer. Prior to joining Kiwetinohk, he worked with a major International and Canadian oil and gas producer. Farid's main achievement as Director of Drilling Engineering with Seven Generations Energy was developing and adapting technologies to reduce drilling time by 65%. This reduction in drill days eliminated carbon footprint by half. Over his 8 years at Seven Generations, Farid had technical oversight of drilling for more than 400 wells with an estimated total lateral length exceeding 1,000 kilometres. Key achievements included establishing a real-time operation center to provide remote steering for more than 10 drilling rigs. This center reduced field personnel requirements and reduced consumption of goods and services making a major contribution to GHG reduction. Farid holds a Bachelor of Science in Petroleum Engineering, a Master of Engineering in Well Construction and a PhD in Drilling Engineering from the University of Calgary. He is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Farid served Kiwetinohk as VP Drilling from 2018 to November 2021. Farid is currently on a career development / operations effectiveness assignment, applying his project management skill in the Power Division and providing upstream expertise to ensure effective vertical integration.

Tim Alberts
Vice President, Production

Tim Alberts started his career in the energy industry as a rig worker in Northern Alberta and British Columbia. He then moved on to field operations including oil wells, gas wells, batteries and gas plants. He spent several years as a Field Foreman at AltaGas dealing with midstream facilities. He was a Field Foreman at Samson Canada which was purchased by Seven Generations Energy in 2008.

Tim established Seven Generations operations headquarters in Grande Prairie, Alberta, starting with 3 employees and exceeding 100 when he left in 2017. Tim spearheaded community relations efforts, including First Nations initiatives, and enjoyed an outstanding reputation and relationship with the community.

Tim was Director of Operations and charged with managing many different groups including production, safety, office staff and camps. He had a hand, either directly or indirectly, in facility design, super pad concept, artificial lift design, start-ups and turnarounds. He was a leader of the concurrent operations initiative that allowed the company to have several disciplines on the same lease, sharing services and working safely.

Mike Carlson
Vice President, Completions

Mike Carlson holds a B.Sc. in chemical engineering from the Schulich School of Engineering, University of Calgary (2008). He started working in the oil and gas business as an operator's assistant for Passage Energy Inc. in 1998. From 1998 until 2008 Mike served four Canadian oil and gas developers, including Krang Energy Inc. for a two-year engineering internship with a focus on reservoir engineering, North American Oil Sands Ltd., and Statoil/Statoil Hydro with a focus on reservoir engineering and corporate planning.

From 2008 to 2018, Mike worked at Seven Generations Energy Ltd. Starting with duties in corporate planning, reservoir, and production engineering, and later founding the completions team as Manager and then Director of Well Completions. During that period, Mike was leader of the entire completions operation for Seven Generations Energy Ltd., managing all aspects of designing and placing hydraulic fracture treatments, as well as developing and improving upon industry standards for well completion and well intervention. Mike had oversight responsibilities for an estimated 10,000 individual hydraulic fracture stimulations.

Mike and his wife, Natalia (an environmental engineer) share a passion for the environment and have privately recently begun an independent reclamation project on a small patch of Alberta forest.

Jim Floyd
Senior Vice President, Power, Green Energy Division

Jim Floyd was a founder of Kiwetinohk, responsible for establishing the power team and the power strategy and holds the position of Senior Vice President, Power. Jim is a Registered Electrical Engineering Technologist and has extensive experience in the power industry. He also holds an LC designation from the National Council of Lighting Professionals. He has, during his career, led several multi-discipline teams of engineers, technologists and tradesmen, having designed and, or, constructed:

- AC and DC transmission and substation projects.
- Power systems for light rail transit projects in Calgary and in Edmonton.
- Unground Residential Distribution power projects.
- Fibre optic systems
- Roadway and sports lighting

Some of the major projects included:

- 3 phases of Edmonton's South Light Rail Transit Project,
- Heartland Transmission Project,
- Western Alberta Tie Line Project,
- Manitoba Bi-Pole Transmission Project.

From 2002 to 2008, Jim was the President of the Caltech Group. During that time period the Caltech Group grew from two companies with 40 staff to five companies with 180+ staff. From 1977 to 2001 he worked at the ENMAX Corporation initially as a designer and later managed several divisions including; Underground Residential Power Distribution, Streetlighting, LRT, Telecommunications, Fibre Optics and Strategic Initiatives. From 2018 through 2019, he was appointed by the Minister of Energy to chair the Transmission Facilities Cost Monitoring Committee for the Alberta Department of Energy.

Jim likes to serve his community. From 2008 to 2017, Jim was a Board Member of Theatre Calgary and from 1986 to 1990 Jim was Vice Chairman of Results with Speedskating for the 1988 Winter Olympic Games. Jim has also found a way to serve through his hobby of running. He became a running coach with the Running Room and has mentored other long-distance runners in the Calgary area.

Craig Parsons
Vice President, Finance, Green Energy Division

Craig has a B.Sc. in Finance from Arizona State University and holds an MBA specializing in Oil and Gas and Carbon Management from London Metropolitan University.

Prior to joining Kiwetinohk, Craig helped to create a new carbon offset protocol for converting waste heat to power, and successfully developed and financed five projects under the new protocol. He later managed the processing and sale of carbon credits for the projects.

Craig has worked as SVP and CFO of both power and oil and gas firms, successfully managing both a TSX listing and seven power project financings. Over the years he has provided financial and economic analysis, financial modeling, accounting function oversight, risk management and commodity marketing and sales.

Dobromir Filip
Director of Engineering, Green Energy Division

Dobromir completed bachelor and masters degrees in mechatronics in Slovakia before earing earning M.Sc. and PhD degrees in electrical engineering at the University of Calgary. During his study at U of C, Dobromir completed 17 publications, two patents, and 1 copyright. Dobromir is a multidisciplinary engineer with a research and practical experience in various fields including power generation.

Dobromir started his industry career as Research and Development Engineer for Genalta Power, where he transitioned through various roles: acting CTO, project specialist, project engineer, lead scientist, and consultant. Dobromir was the key technical expert in numerous engineering studies and power generation projects that include thermal generation and renewables. At Genalta, Dobromir was involved in engineering and construction of power projects including projects 80MW and larger. Example projects include: a remotely operated, 15MW thermal power plant, a 2.2MW supercritical organic rankine cycle plant, microturbines project with patented, plume-reducing exhaust stacks, and a 20 MW reciprocating engine plant operated on sour gas. Dobromir co-authored several patents and trademarks under Genalta.

Dobromir is a member of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). Dobromir is also a member of the Institute of Electrical and Electronics Engineers IEEE and the American Society of Mechanical Engineers. Dobromir was official reviewer for several IEEE journals.

At Kiwetinohk's Green Energy Division, Dobromir presently leads all aspects of engineering from new technology windowing, through business development to project management.

Nikki Sitch
Manager, Land and Community Inclusion

Manager, Land and Community Inclusion, Nikki Sitch has been with Kiwetinohk for three years and is a Landman with over 20 years of experience in all facets of land management in Western Canada. She has gained knowledge and experience in exploration, development, regulatory, acquisitions and divestitures, in both surface and mineral land. Nikki has a passion for learning and education and enjoys giving back to the land community through volunteering, teaching and mentoring.

Nikki has been active in the CAPL, serving as a board member for seven years including serving as President from 2015 to 2016. Nikki currently serves as Chair of CAPL's Field Acquisition Management Committee a sub-group which she has served since 2004. That committee established the Professional Surface Landman designation in Canada. Nikki was honored with the CAPL Bright Lights Award in 2007. Nikki served on CAPL Education Committee including as Chair (2006 to 2010) helping to create seven new surface land courses.

Nikki is also member of the APPL. She served on the AAPL board from 2016 to 2019.

Nikki represents Kiwetinohk on the South Duvernay producers group where she chairs the Communications Committee and the Tenure Sub-committee.

Nikki has been active with Calgary's Mount Royal University as a Founding member of the committee that created the Petroleum Land Business Extension Certificate offered by that school. Nikki developed and taught a course on Surface Rights and Regulations Overview and she taught Crown Surface Administration for one semester.

Nikki holds the following designations:

- Bachelor of Commerce in Petroleum Land Management (PLM), 2010
- Alberta Land Agent's License – 2002-present
- Professional Surface Landman (PSL) - 2008
- Professional Landman (P.Land) – 2008

Nikki has created enduring friendships with community leaders, industry counterparts, landowners, and indigenous leaders. She has negotiated and supervised the acquisition of more than 2,500 surface agreements that resulted in successful project applications. Nikki has acquired more than 400 square miles of land and negotiated more than a dozen deals valued between $100K to $10MM. Nikki created and grew the Operations, Mineral, and Upstream departments at Aim Land Services Ltd.

Joanne Germaine
Health, Safety and Environment Controller

HSE Controller of Kiwetinohk, Joanne is an HSE professional with a career focused on health, safety and environment leadership, atmospheric emission strategies, development of comprehensive, fit-for-purpose safety programs and stewardship of ARO initiatives. At Kiwetinohk, Joanne is charged with establishing, implementing, coaching, monitoring and measuring and reporting with respect to programs to differentiate in health, safety and environmental performance.

Joanne holds a Certified Engineering Technologist (CET) designation and is a Registered Technologist in Agrology (RTAg). She brings over 20 years of experience in Health, Safety and Environment management, most recently in leadership positions with high growth, upstream companies.

James Carlson
Manager, Environment – Land and Water

James Carlson holds a Petroleum Technology Certificate from the Southern Alberta Institute of Technology. His key duties, as a member of the environmental team at Kiwetinohk, include the procurement and transportation of fresh water for drilling, completion and workover operations and assessment and management of the Company's Asset Retirement Obligations. Prior to returning to school to earn his technology diploma, James managed fresh water sourcing for Seven Generations Energy Ltd. sourcing water for more than 100 new wells per year.

Kevin Nielsen
Controller

Kevin Nielsen joined Kiwetinohk in 2018 as Corporate Controller. Kevin is a Chartered Accountant and has a Bachelor of Commerce (Accounting) degree from the University of Alberta. Prior to joining Kiwetinohk, Kevin spent 18 years in public practice at an international accounting firm where he was a partner and provided financial leadership on internal and external reporting, accounting, internal controls, treasury, tax, and risk management to domestic and international oil and gas clients.

Kevin is active within the energy industry having been a short-term technical expert with the International Monetary Fund supporting various IFRS training missions most recently in Africa, is a governor at the

Calgary Petroleum Club and leads the Joint Interest Research Committee of the Petroleum Accountants Society of Canada.

See "*Directors and Officers*" for a biography of the Company's Board members and Executive Officers.

Kiwetinohk has engaged the staff complement indicated in the table below.

	Number of Employees	
Employees Engaged in Full-Time Service	**as at Dec. 31, 2020**	**as at Sept. 30, 2021**
Calgary Office	21	42
Drayton Valley Field Office	1	1
Grande Prairie Field Office	2	2
Simonette Assets	--	15
Consultants Engaged in Full-Time Service		
Calgary Office	8	3
Drayton Valley Field Office	--	1
Thorhild Region	--	1

Specialized Skill and Knowledge

Kiwetinohk employs individuals with a range of professional skills in the course of pursuing and executing its business plan. These professional skills include, but are not limited to, geology, petrophysics, geomechanics, reservoir engineering, drilling engineering, environmental science and engineering, petroleum completions, workover and abandonment engineering, petroleum production engineering, facility design engineering, construction project management, power generation engineering, chemical process engineering, oil and gas marketing, project planning, capital budgeting, financial analysis and forecasting, asset and corporate valuation, accounting and business development. In addition, Kiwetinohk has available to it various specialized consultants to assist it in areas where it does not need full time employees. Kiwetinohk also deploys consultants in areas in which consultants are deemed to be more effective.

Environmental, Health and Safety Policies

Kiwetinohk supports and promotes: (a) the protection of the health and safety of all persons associated with Kiwetinohk's operations, including employees, contractors and service providers; (b) the protection of the biophysical environment; and (c) the relationship of Kiwetinohk with the communities nearest to its operations through the implementation and communication of Kiwetinohk's health, safety, environmental protection and community engagement programs, policies and procedures.

Kiwetinohk has established guidelines and management systems to promote compliance with health, safety and environmental laws. Kiwetinohk endeavors to ensure that on an ongoing basis, it is in material compliance with health, safety and environmental regulations. Stakeholder awareness and responsiveness to stakeholder expectations is a key component of the duties of all personnel in the service of Kiwetinohk. Kiwetinohk has contracted the services of an external consultant to provide it with expert advice on health, safety, environmental and regulatory compliance issues and to help it ensure that appropriate safety precautions are implemented. In addition, Kiwetinohk may consult with government and other stakeholders from time to time, either as an individual company or through industry groups, as appropriate, to contribute to the development of the environmental regulatory framework applicable to Kiwetinohk's business so that Kiwetinohk and the industries in which it is engaged serve their stakeholders more effectively.

Kiwetinohk expects water use regulations and requirements will continue to increase as climate change, community and industrial growth may affect water availability. As such, Kiwetinohk is actively monitoring water availability and acceptability with plans to report on water use and disposal, and reduction strategies, to stakeholders in 2022.

Asset Retirement Obligations

As of July 1, 2021, Kiwetinohk had $166.7 million of asset retirement obligations.

Kiwetinohk takes a lifecycle approach to its well development and reclamation planning, spreading the cost of ultimate asset retirement and reclamation over the value generation phase of operations in a uniform, undiscounted manner. Each year, a portion of the revenue generated from each phase of the Company's operations will be either deployed in asset retirement or set aside in an account to offset future asset retirement activities.

GHG Emissions

Managing, mitigating and avoiding GHG emissions while producing reliable and low-cost natural gas, electricity and hydrogen is core to Kiwetinohk's business plan. Kiwetinohk will develop its position as a leader in greenhouse gas emissions reductions from upstream natural gas production through targeted focus on reducing emissions of both CO_2 and methane, a GHG with a climate impact 25 times greater than CO_2 over a 100-year period.

Kiwetinohk's upstream methane emissions are related to venting and flaring, which is strictly regulated in Alberta and BC, and fugitive emissions, largely from pneumatic equipment and other applications requiring gas for instrumentation. Kiwetinohk undertakes methane leak detection and repair at its well sites and pipelines, deploying new technology and equipment in line with the government's stated goal of reducing methane emissions by 45% by 2025.

Kiwetinohk expects its upstream operations in the Duvernay and Montney to reflect performance consistent with other assets in the area, which are among the lowest emitting natural gas wells in North America.[13]

Kiwetinohk will publish its upstream emissions intensities and GHG reduction strategy and plan in 2022.

Fresh Water Use

Kiwetinohk uses fresh water primarily in its drilling and completions activities associated with safe and efficient hydraulic fracturing of natural gas reservoirs.

Fresh water use and disposal of process-affected water are strictly regulated in Alberta and British Columbia. Kiwetinohk obtains water licences for all its water use, working with regulators, communities and Indigenous groups to ensure water use is sustainable within scientifically-determined regional watershed thresholds.

Competitive Conditions

The facets of the North American energy business that Kiwetinohk participates in, particularly upstream oil and gas and power development and generation, are open to new entrants able to secure funding need to secure and develop assets. In most of these facets Kiwetinohk faces many competitors ranging from new entrants to long-established companies, while in others, the business entry is more controlled or regulated. These include access to the electrical power gathering and distribution grid and large transmission pipeline systems. In comparison, for the oil and gas producing and development business there are limited entry points and often multiple companies competing to acquire available entry points. Climate risks have motivated governments to intervene in the economy to accelerate the transition to cleaner, low carbon energy sources. Government interventions in the energy industry affecting the Alberta

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[13] MacKay, K, Lavoie, M, Bourlon, E *et al.*, "Methane emissions from upstream oil and gas production in Canada are underestimated." (2021) Sci Rep 11, 8041, DOI: https://doi.org/10.1038/s41598-021-87610-3.

petroleum business have included subsidies, penalties, taxes on carbon emissions, ceilings, and administrative delays that tilt the business environment in the favor of some companies over others, affecting profitability and the reliability of market forecasts.

Environmental Issues

Ongoing access to Kiwetinohk's oil and gas resource base requires dedicated technical and environmental expertise and constructive engagement and collaboration with stakeholders, including the Government of Alberta and the communities and Indigenous nations in the Company's operating area.

Wherever possible Kiwetinohk seeks to reduce its environmental operational footprint through efficient and planned co-location of natural gas, pipeline, power generation, and carbon management assets, building partnerships and synergies with existing industries, companies, and communities in the area to prevent waste and maximize value. Kiwetinohk's approach is to locate facilities in areas with existing access to infrastructure and markets, and to find opportunities to work with communities and industrial neighbours to create hubs for value chain activities and other commercial partnerships.

Locating future natural gas processing and electrical generation projects in areas with advantaged access to oil and gas processing, transportation and electricity infrastructure also minimizes Kiwetinohk's impact on the environment and communities, reduces regulatory risks and reduces transportation costs.

Kiwetinohk complies with local, provincial and federal environmental regulations as a baseline for its corporate performance and seeks to meet or exceed legally required environmental performance standards for land, air and water across the lifecycle of its operations.

Cyclical Nature of Business

The volatility of crude oil and natural gas prices has had and will continue to have a significant impact on Kiwetinohk's financial performance. In general, natural gas prices in Canada are seasonal in nature, with higher prices existing in the winter months (November to March) and lower prices in the summer months (April to October). Natural gas prices are also affected by the amount of gas in local and North America-wide storage, or inventory within the market. These seasonal variations provide an overprinting influence on larger, longer-term economic trends. For example, large supply changes have occurred such as the large increase in North American supply that resulted from the application and commercialization of horizontal well, multi-stage hydraulic fracture technology to very low permeability resources such as gas shales that occurred in the last two decades. The rapid evolution of technology affected the competitiveness of companies and resource bodies and the technology is still evolving. In recent years, companies in plays such as Alberta's Montney and Duvernay formations have experimented with such development design parameters as well lateral length, well lateral spacing, hydraulic fracture spacing, hydraulic fracture size and fracture fluid.

Kiwetinohk's operations are also impacted by seasonality, including road closures to heavy loads occurring in the spring months, which can delay access to drilling locations, and seasonal environmental protection requirements such as protected caribou habitat. There are often periods of extreme hot and cold weather events that can cause the shut-down of some operations.

Environmental Compliance and Performance

The crude oil and natural gas and power industries are currently subject to environmental regulations pursuant to a variety of municipal, provincial and federal legislation. The regulations with respect to air emissions, water, land use and remediation are evolving and in recent years have exposed a requirement for significant change to Kiwetinohk's industry, which are expected to continue during and throughout this energy transition. Compliance with such legislation may require significant expenditures or result in operational restrictions. Breach of such requirements may result in suspension or revocation of necessary licences and authorizations, civil liability for pollution damage and the imposition of material fines and penalties, all of which might have a significant negative impact on reputation, earnings and overall competitiveness of Kiwetinohk.

Kiwetinohk believes it is in material compliance with applicable environmental laws at this time. Kiwetinohk is committed to meeting its responsibilities to protect the environment in all jurisdictions in which it operates, and will continue to take steps in this regard. Following Distinction's emergence from the CCAA process, it was determined by Kiwetinohk management that Distinction was not in full compliance with applicable environmental regulations and written voluntary self-disclosures identifying the shortfalls were submitted to the AER and AEP, who are cooperating with Kiwetinohk to become fully compliant. Kiwetinohk believes a fully compliant status can be achieved in the first quarter of 2022.

For a description of the financial and operational effects of environmental protection requirements on the capital expenditures, earnings and competitive position of Kiwetinohk see *"Risk Factors – Environmental, Health and Safety Requirements*".

INDUSTRY CONDITIONS

Power Industry

Historically, the power industry in Alberta was largely characterized by a small number of monopolistic electric utilities producing electricity for a captive customer base. However, industry trends and governmental and regulatory initiatives have introduced competition and the ability to purchase electricity from a variety of suppliers, including non-utility generators, power marketers, public utilities and others. This has created opportunities for investment in generation facilities by independent power producers.

Alberta Electricity Market Background

Alberta has a deregulated and competitive wholesale electricity generation market. Since deregulation, which began in 1996 and was completed in 2001, the development of new generating capacity in Alberta has been undertaken by independent power producers and has been subject to market forces rather than a regulated "cost-of-service" model. The Alberta electricity market is an energy-only market where generators are paid for the electricity they produce rather than their ability to produce electricity as occurs in a capacity market. Electricity bought and sold in Alberta is exchanged through the wholesale electricity market (the "**Power Pool**") and is dispatched in accordance with an economic merit order administered by the AESO. See "*Legal and Regulatory Regime – Power Industry – Alberta*".

Power Prices in Alberta

In Alberta, electricity is sold and bought through the wholesale electricity market, the Power Pool. Generators may earn revenues from energy sales by submitting supply offers to the AESO. No PPAs or sales contracts are required to sell energy into the Alberta market. For every hour of the day, generators submit offers specifying the amount of power they will provide and the price at which they are willing to supply it. Offer prices can range from a low of $0/MWh to a maximum of $999.99/MWh. The offers are arranged from lowest to highest price to create the energy market merit order. The system controller dispatches generation from the merit order in order of ascending offer price until supply satisfies demand. Dispatched generation is said to be in merit; generation that is not dispatched is out of merit. The highest priced in-merit generation in each minute sets the system marginal price for that one-minute period.

The pool price is the simple average of the 60 system marginal prices in the one-hour settlement interval. All energy generated in the hour and delivered to the Alberta's electric system receives a uniform clearing price — the pool price — regardless of the price at which it was offered. System load draws energy from the grid and pays the pool price.

In 2020, 208 participants in the Alberta wholesale market transacted approximately $5.7 billion of energy with pool prices averaging $46.72/MWh[14]. On-peak period pool prices averaged $54.72/MWh while off-peak pool prices averaged $30.71/MWh[15]. Alberta power generators also have the ability, if they choose to do so, to contract their energy supply with customers at prices and on terms that may vary from the pool price pursuant to a private PPA.

Power Generation in Alberta

At year-end 2020, Alberta's installed generation capacity totaled just over 16,000 MW including approximately 5,100 MW of coal-fired generation, 8,000 MW of gas-fired generation (5,100 MW cogeneration, 1,800 MW combined cycle and 1,100 MW simple cycle) and 2,800 MW of renewables (900 MW hydro, 100 MW solar and 1,800 MW wind)[16].

In 2015, the Government of Alberta announced that emissions from coal-fired generation facilities in the province must be eliminated by 2030. Most historical coal-fired generation facilities are expected to convert to natural gas operation[17]. Coal-fired generation capacity has declined from approximately 6,300 MW at the beginning of 2016 to approximately 5,100 MW at the end of 2020[18]. In 2021, over 3,500 MW of coal-fired generation is expected to be retired[19].

Over the past 10 years, more than 1,000 MW in wind and solar power generation facilities have been added to Alberta's power supply[20]. Wind and solar generation currently represent approximately 12% of the province's total installed capacity[21]. In 2017 and 2018, the AESO procured renewable electricity generation through the Renewable Energy Program ("**REP**") to support the transition away from coal and the goal of generating 30 percent of Alberta's electricity from renewable sources by 2030. The REP is based on a "contract for difference" pricing mechanism pursuant to which successful proponents are guaranteed a set price for electricity production. Any difference between that set price and the market-based pool price is paid to the proponent by the AESO. Despite the cancellation of the REP in June 2019, the AESO predicts that 4,145 MW of renewable projects will be developed over the next 20 years, with about 1,280 MW of that amount being developed to supply renewable corporate PPAs[22].

As more renewables are integrated into the grid, their intermittent nature can pose challenges in terms of, among other things, maintaining system reliability. Electricity generation and storage facilities that can immediately respond to fluctuations in the supply of renewable electricity generation due to changes in sun and wind conditions can play an important role in supporting system reliability and keeping supply and demand in balance. In Alberta, as coal power is phased out, AESO forecasts renewables and natural gas to account for an increasing share of total installed capacity, ultimately reaching 31% and 67%, respectively, by 2031.

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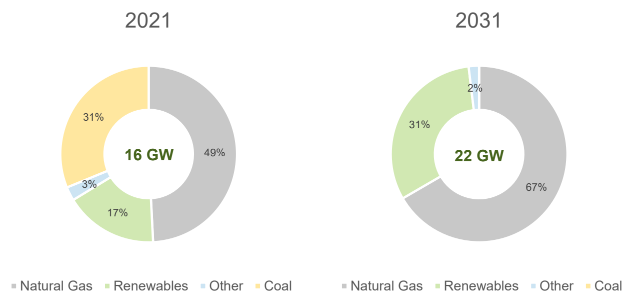
[14] "AESO 2020 Annual Market Statistics Report" (March 2021), online: *aeso* <https://www.aeso.ca/assets/Uploads/2020-Annual-Market-Stats-Final.pdf>.
[15] *Ibid.*
[16] *Ibid.*
[17] "AESO 2021 Long Term Outlook" (June 2021), online: *aeso* <https://www.aeso.ca/assets/Uploads/grid/lto/2021-Long-term-Outlook.pdf>.
[18] "AESO 2020 Annual Market Statistics Report" (March 2021), online: *aeso* <https://www.aeso.ca/assets/Uploads/2020-Annual-Market-Stats-Final.pdf>.
[19] "AESO 2021 Long Term Outlook" (June 2021), online: *aeso* <https://www.aeso.ca/assets/Uploads/grid/lto/2021-Long-term-Outlook.pdf>.
[20] "AESO 2020 Annual Market Statistics Report" (March 2021), online: *aeso* <https://www.aeso.ca/assets/Uploads/2020-Annual-Market-Stats-Final.pdf>.
[21] *Ibid.*
[22] "AESO 2021 Long Term Outlook" (June 2021), online: *aeso* <https://www.aeso.ca/assets/Uploads/grid/lto/2021-Long-term-Outlook.pdf>.

Total Installed Capacity



Source: 2021 total installed capacity as at January 1, 2021 per AESO market statistics.
Source: 2031 total installed capacity based on AESO Reference Case per July 2021 Long Term Outlook presentation.

Upstream Oil and Natural Gas Industry

Pricing and Marketing of Natural Gas, Crude Oil and NGL

Natural Gas

Supply and demand determine the price of natural gas which is calculated at the sale point, being the wellhead, the outlet of a gas processing plant, a natural gas trading hub (for example, Nova Inventory Transfer ("**NIT**"), being the pricing point used for natural gas from the Western Canada Sedimentary Basin), at a storage facility, at the inlet to a pipeline system or at the point of receipt by the consumer. Accordingly, the price for natural gas is dependent upon a producer's own arrangements (whether long or short term contracts and the specific point of sale). As natural gas is also traded on trading platforms such as the Natural Gas Exchange ("**NGX**") or the NYMEX in the United States, spot and future prices can be set by such supply and demand. Natural gas exported from Canada is subject to regulation by the CER and the Government of Canada. Exporters are free to negotiate prices and other terms with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the CER and the Government of Canada. 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 and price of transportation, length of contract term, weather conditions, supply/demand balance and other contractual terms of sale.

The Energy Information Agency ("**EIA**") expects U.S. consumption to decrease by 1.1% in 2021 and increase by 0.7% in 2022. The EIA forecasts electric power sector consumption of natural gas to increase by 1.3% in 2022, based on an expected decline in natural gas prices in 2022.

In Alberta, electricity generation and oil sands production are expected account for most of the increase in natural gas use. Demand for natural gas in electricity generation will be driven by coal-to-gas switching and cogeneration. The Company expects natural gas demand to grow with production from in-situ facilities. Another tailwind for natural gas demand is growing demand from hydrogen manufacturing[24].

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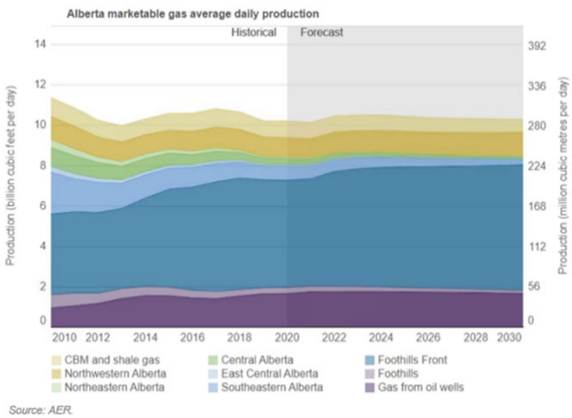
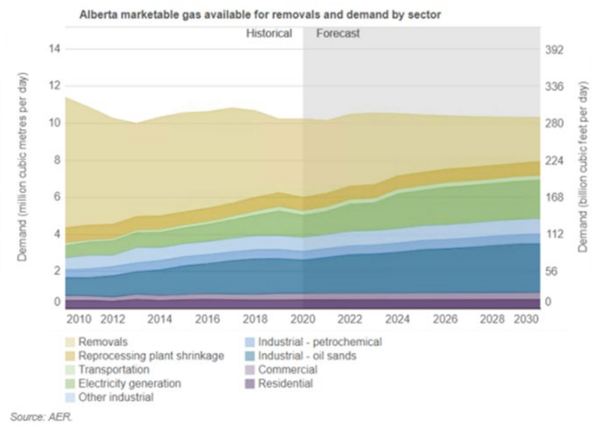
[23] "Short Term Energy Outlook" (4 November 2021), online: *EIA* <https://www.eia.gov/outlooks/steo/>.
[24] "Alberta Energy Outlook" (June 2021), online: *AER* < https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98>.





The EIA forecasts that by 2030, marketable natural gas production will increase marginally in Alberta by 0.1 bcf/d. Trends expected in Alberta natural gas production from 2021 to 2030 include: (a) gas producers continuing to target the most productive plays in the province; this means there will be fewer new wells than were historically needed to maintain production levels; (b) liquids-rich plays will likely attract the most attention given their profitability; generally, this will mean higher natural gas liquids in the raw gas stream; and (c) consolidation of operations; this is likely to progress as producers seek to optimize infrastructure use and reduce operating and capital costs[25].

Crude Oil

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

The increase in economic activity and easing of the COVID-19 pandemic contributed to rising energy use in 2021 to date. The EIA forecasts global consumption of petroleum and liquid fuels to grow by 5.3 million bbl/d in 2021, with a further increase of 3.7 million bbl/d in 2022[26]. The spread of COVID-19 variants and the effectiveness of the vaccines against these variants are significant risk factors that could impact a full and sustained global recovery.

The EIA forecasts production growth in 2021 and 2022 for both non-OPEC and OPEC+. With respect to non-OPEC production outlook, the EIA forecasts production growth of 1.1 million bbl/d in 2021 and 3.1 million bbl/d in 2022.

Natural Gas Liquids

The pricing of condensates and other NGLs such as ethane, butane and propane sold in intra-provincial, interprovincial and international trade is determined by negotiation between buyers and sellers. Such prices depend, in part, on the quality of the NGL, 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.

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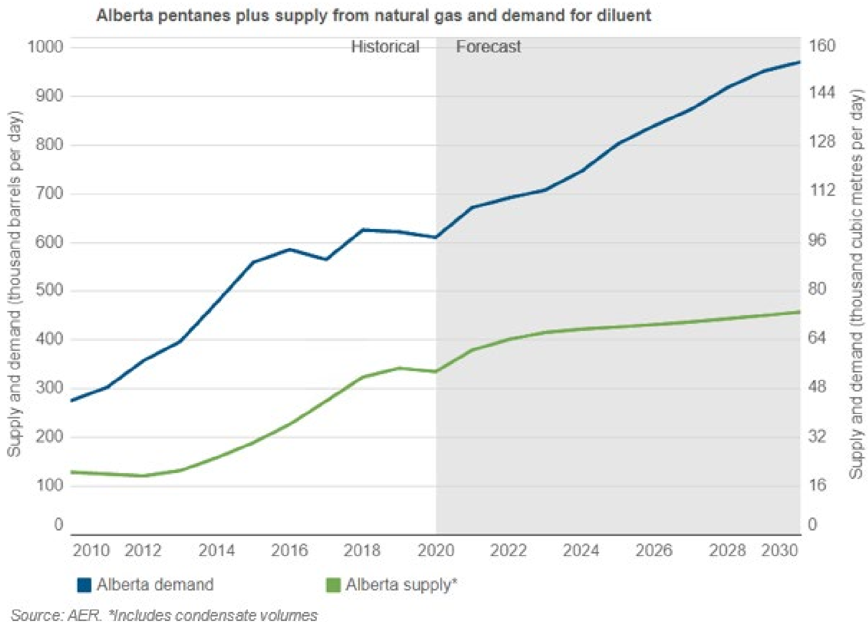
[25] *Ibid.*
[26] "Short Term Energy Outlook" (4 November 2021), online: *EIA* <https://www.eia.gov/outlooks/steo/>.



Exports of Crude Oil, Natural Gas and NGL from Canada

On August 28, 2019, the NEB became the CER. Regulations made under the NEB Act, including the Part VI Regulation, remain in force under the CERA until they are replaced or updated through an ongoing review process.

Exports of crude oil, natural gas and NGL from Canada are subject to the CERA and the Part VI Regulation. The CERA and the Part VI Regulation authorize crude oil, natural gas and NGL exports under: (a) short-term orders for up to one or two years depending on the substance and up to 20 years for quantities of natural gas (other than NGL) not exceeding 30,000 m3 per day; or (b) long-term export licences of up to 40 years for natural gas and up to 25 years for crude oil and other substances (e.g., NGL). Applications for long-term export licences are subject to a CER review, which may involve a public hearing. The CER can approve an application if it is satisfied, among other considerations, that the proposed export volumes are not greater than Canada's reasonably foreseeable needs. In addition to CER approval, long-term export licences currently require various other ministerial and federal Cabinet approvals.

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 Government of Canada.

Transportation Constraints and Market Access

One major constraint to the export of crude oil, natural gas and NGL is the deficit of capacity to transport production from Western Canada to the United States and other international markets. Although certain pipeline and other transportation and export projects are underway, many proposed projects have been cancelled or delayed due to regulatory hurdles, court challenges and economic and other socio-political factors. Due in part to growing production and a lack of new and expanded pipeline and rail infrastructure capacity, producers in Western Canada have experienced discounted commodity pricing relative to international markets in the last several years.

Pipelines

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

Under the Canadian Constitution, interprovincial and international pipelines fall within the Government of Canada's jurisdiction and, under the CERA, construction of interprovincial and international pipelines (new or expansion capacity) will require a federal regulatory review and, in some cases, federal Cabinet approval before they can proceed.

Marine Tankers

Bill C-48 received royal assent on June 21, 2019, enacting the *Oil Tanker Moratorium Act* (Canada), which imposes a ban on oil tankers carrying more than 12,500 metric tons of crude oil or prescribed persistent oil products from stopping, loading or unloading at ports or marine installations along British Columbia's north coast. The ban may impact the future construction of oil pipelines to, and export terminals located on, the portion of the British Columbia coast subject to the moratorium.

Crude Oil and Bitumen by Rail

On February 19, 2019, the Government of Alberta announced that it would lease 4,400 rail cars capable of transporting 120,000 bbls/d of crude oil out of the province to help alleviate the transportation constraints impacting Canadian oil prices. In the spring of 2019, the Government of Alberta announced it would cancel the program and assign the transportation contracts to industry proponents. In February 2020, the Government of Alberta announced it had sold $10.6 billion worth of crude-by-rail contracts to the private sector.

In February 2021, Transport Canada approved certain changes relating to reduced speed limits as set out in the Rules Respecting Key Trains and Key Routes under the *Railway Safety Act* (Canada).

Natural Gas

Natural gas prices in Alberta and British Columbia have been constrained in recent years due to increasing North American supply, limited access to markets and limited storage capacity. Producers that secure firm access to infrastructure to transport their natural gas production out of Western Canada may be able to access more markets and realize improved pricing. Producers without firm access may be forced to accept spot pricing in Western Canada, which in the last several years has generally been discounted.

Required repairs or upgrades to existing pipeline systems in Western Canada have also led to further reduced capacity and apportionment of access, which has been further exacerbated by storage limitations. However, NOVA Gas Transmission Ltd. (a subsidiary of TC Energy) has added approximately 1 bcf/d of capacity to NGTL since 2019 that has served to somewhat stabilize supply and pricing, particularly during periods of maintenance on the system.

Additionally, an expansion to the NGTL has been approved, with construction of all components expected to be completed in the second quarter of 2022. Further, NGTL implemented a firm transfer to storage pilot project on April 1, 2021.

LEGAL AND REGULATORY REGIME

Upstream Oil and Natural Gas Industry

Crown Land and Mineral Tenure

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

In response to the COVID-19 pandemic, the provincial governments of Alberta and British Columbia announced measures to extend or continue Crown leases and permits that may have otherwise expired in the months following the implementation of pandemic response measures. The British Columbia Ministry of Energy, Mines and Petroleum Resources announced that it was suspending posting requests and dispositions of petroleum and natural gas tenure until further notice due to the COVID-19 pandemic.

Each of the provinces of Western Canada have implemented legislation providing for the reversion to the Crown of mineral rights to deeper, non-producing geological formations at the conclusion of the primary term of a lease or licence. 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. British Columbia has a policy of "zone specific retention" that allows a lessee to continue a lease for zones in which it can demonstrate the presence of oil or natural gas, with the remainder reverting to the Crown.

While the majority of the mineral rights in Western Canada are Crown-owned, there is, to a lesser extent, private ownership of crude oil and natural gas (i.e. freehold mineral lands). Rights to explore for and produce privately owned crude oil and natural gas are granted by a lease or other contract on such terms and conditions as may be negotiated between the owner of such mineral rights and companies seeking to explore for and/or develop crude oil and natural gas reserves.

To develop crude oil and natural gas resources, it is necessary for the mineral rights holder to have access to the associated surface lands, which can be privately or Crown-owned. Each province has its own process for obtaining surface access to conduct crude oil and natural gas production operations, including notification requirements and providing compensation to affected persons where required (for example, for lost land use and surface damage).

An additional category of mineral rights ownership includes ownership by the Government of Canada in trust of mineral rights located within First Nation reservations designated under the *Indian Act* (Canada). Indian Oil and Gas Canada is responsible for managing and regulating oil and gas resources (mineral and surface lands) on First Nation reserve lands which have been designated for such use by the relevant First Nation in accordance with the *Indian Act* (Canada).

Where a First Nation has designated an area of its reserve land for crude oil and natural gas use, those activities are governed by the IOGA and associated regulations. In 2009, the Canadian Parliament passed the Modernized IOGA; however the amendments were delayed until the Government of Canada was able to complete consultations and update the 2019 Regulations. The Modernized IOGA and the

2019 Regulations came into force on August 1, 2019 and further regulations are currently being developed. The Company does not have any interests in operations on Indian reserve lands.

In July 2021, the British Columbia Supreme Court found that the Government of British Columbia breached the Blueberry River First Nation's Treaty 8 rights by failing to consider cumulative effects when authorizing activities, including natural gas extraction and other industrial activities, to occur on the First Nation's traditional territory. The Blueberry River First Nation's traditional territory overlaps with some areas of the Montney formation. The court ruled that the Government of British Columbia can no longer authorize industrial development on the Blueberry River First Nations' traditional territory if such development will breach the First Nation's treaty rights. Furthermore, the decision may lead to similar cumulative effects claims across Canada, particularly across the Prairies and northern Ontario which have historic numbered treaties similar to Treaty 8. The British Columbia Supreme Court judgment was suspended for six months to allow the Government of British Columbia and the Blueberry River First Nation to negotiate changes to the regulatory regime that will respect and protect the First Nation's treaty rights. On October 7, 2021, the Government of British Columbia and the Blueberry River First Nation reached an initial agreement which has been characterized as a first step in responding to the British Columbia Supreme Court's decision. Under that agreement, the Province of British Columbia provided $65 million in funding to Blueberry River First Nation to support land restoration and cultural programs. The Province of British Columbia and the Blueberry River First Nation are also working to finalize an interim approach for reviewing new natural resource activities that balance Treaty 8 rights, the economy and the environment, after which, long-term solutions will be negotiated. See "*Risk Factors – Risks Related to the Company – Indigenous Land Claims and Other Community Opposition*".

The outcome of negotiations between the Province of British Columbia and the Blueberry River First Nation is expected to be watched by other First Nations with treaties in Canada that are seeking greater influence over or to halt industrial development in their territories. The Province of British Columbia has said that it is starting dialogue with other Treaty 8 First Nations on matters of treaty rights.

Royalties and Incentives

Each province has legislation and regulations that govern royalties, production rates and related matters. The royalty regime in a given province is a significant factor in the profitability of oil sands projects and crude oil, natural gas and NGL production. Royalties payable on production from lands where the Crown does not hold the mineral rights are determined by negotiation between the mineral freehold owner and the lessee, although production from such lands is subject to certain provincial taxes. Royalties from production on Crown lands are determined by provincial regulation and are generally calculated as a percentage of the value of production.

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

Occasionally, Western Canadian governments establish incentive programs to encourage the exploration and development of natural resources. For example, such programs have historically included production volume-based incentives, royalty rate reductions, royalty holidays or royalty tax credits. In addition, incentive programs may be introduced to encourage producers to prioritize certain kinds of development or undertake initiatives using new technologies that may enhance or improve recovery of crude oil, natural gas and NGL. One such program is the Government of Alberta Emerging Resource Program. Certain of the Simonette Assets may qualify for the benefits of this royalty program.

The Government of Canada also provides incentives and other financial aid programs to assist businesses operating in the crude oil and natural gas industry. Recently, these programs have included the provisions of direct financial support to companies operating in the crude oil and natural gas industry and/or targeted funding for various initiatives related to industry diversification and environmental matters, and have been administered through federal agencies such as the Business Development Bank of

Canada, Natural Resources Canada, Export Development Canada, and Innovation, Science and Economic Development Canada.

Regulatory Authorities and Environmental Regulation

General

The Canadian crude oil and natural gas industry is currently subject to environmental regulation under a variety of Canadian federal, provincial, territorial, and municipal laws and regulations, all of which are subject to governmental review and revision from time to time. Such regulations provide for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with certain crude oil and natural gas industry operations, such as sulphur dioxide and nitrous oxide. The regulatory regimes set out the requirements with respect to, for example, 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 CO_2E), may impose further requirements on operators and other companies in the crude oil and natural gas industry.

Federal

Canadian environmental regulation is the responsibility of both the federal and provincial governments. While provincial governments and their delegates are responsible for most environmental regulation, the Government of Canada 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 interprovincial 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.

On August 28, 2019, the *Impact Assessment Act* (Canada) (the "**IAA**") replaced the *Canadian Environmental Assessment Act* (the "**CEAA 2012**"). As part of the regulatory transition, the Impact Assessment Agency of Canada ("**IAAC**") replaced the Canadian Environmental Assessment Agency.

The enactment of the *Canadian Energy Regulator Act* (Canada) (the "**CERA**") and the IAA introduced a number of important changes to the regulation of major projects subject to federal jurisdiction and their associated environmental assessments. The Canada Energy Regulator (the "**CER**") has assumed the jurisdiction of the National Energy Board ("**NEB**") over matters that include regulation of interprovincial pipelines, power lines and offshore renewable energy projects, including offshore wind and tidal facilities. In its adjudicative role, the CERA tasks the CER with reviewing applications for the construction, operation and eventual abandonment of those projects under its jurisdiction.

The IAA is similar to the repealed CEAA 2012 in that it relies on a designated project list as a trigger for a federal assessment (the Minister also retains the discretion to designate a project not on the designated projects list). Designated projects that may have effects on matters within federal jurisdiction will generally require an impact assessment administered by the IAAC, a review panel or a jurisdiction undertaking a substituted assessment. In the case of certain pipelines, a joint review panel comprised of members from the CER and the IAAC will undertake the impact assessment. The impact assessment requires a public interest assessment, including consideration of, for example, 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. Designated projects specific to the crude oil and natural gas industry include, for example, new pipelines that require a total of 75 km or more of new right of way and pipelines located in national parks and protected areas, large scale *in situ* oil sands extraction facilities not regulated by provincial GHG emissions caps and certain refining, processing and storage facilities.

The Government of Canada has stated that an objective of the legislative changes was to improve decision certainty and timelines. 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 has to issue its report and recommendation (subject to certain offramps). Designated projects will go through a planning phase where the public and Indigenous peoples are invited to provide information and contribute to planning the assessment (if any), including to determine scope, which the Government of Canada has stated should provide more certainty as to the length of the full review process. The Government of Alberta submitted a reference question to the Alberta Court of Appeal regarding the constitutionality of the IAA and a hearing occurred in February 2021. A decision is pending.

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* (Alberta) and a number of related statutes including the OGCA, the *Oil Sands Conservation Act* (Alberta), the *Pipeline Act* (Alberta) and the *Environmental Protection and Enhancement Act* (Alberta). The AER is responsible for ensuring the safe, efficient, orderly and environmentally responsible development of hydrocarbon resources, including allocating and conserving water resources, managing public lands, and protecting the environment. The AER's responsibilities exclude the functions of the Alberta Utilities Commission ("**AUC**") and the Alberta Land and Property Rights Tribunal (formerly 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 Alberta Land Use Framework ("**LUF**") 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 establishes seven land-use regions and calls for the development of specific regional land-use plans to manage the combined impacts of existing and future land use within each specific region and incorporate a cumulative effects management approach.

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 crude oil and natural gas production. In recent years, hydraulic fracturing has been linked to increased seismicity in the areas in which hydraulic fracturing takes place.

The AER has developed monitoring and reporting requirements that apply to all crude 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**"). Crude 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.

British Columbia

In British Columbia, the *Oil and Gas Activities Act* ("**OGAA**") regulates conventional crude oil and natural gas producers, shale gas producers and other operators of crude oil and natural gas facilities in the province. Under the OGAA, the British Columbia Oil and Gas Commission ("**BCOGC**") has broad powers, particularly with respect to compliance, enforcement and the setting of technical safety and operational standards for crude oil and natural gas activities. The *Environmental Protection and Management Regulation* establishes the government's environmental objectives and requires the BCOGC to consider these environmental objectives in deciding whether or not to authorize a particular activity. In addition, the *Petroleum and Natural Gas Act* (British Columbia), in conjunction with the OGAA, requires proponents to obtain various approvals before undertaking exploration or production work. Such approvals are given subject to environmental considerations and permits, licences and project approvals can be suspended or cancelled for failure to comply with this legislation or its regulations.

The Government of British Columbia has introduced a regime to monitor and manage the risk of induced seismicity related to crude oil and natural gas operations, particularly in northern British Columbia, where hydraulic fracturing is used to access natural gas plays. The Drilling and Production Regulation requires a producer to suspend its operations if they trigger an earthquake with a magnitude on the Richter scale of 4.0 or greater, and to implement mitigation measures approved by the BCOGC before resuming production. In June 2016, the BCOGC amended the permitting process to require all natural gas producers to conduct ground monitoring, and to submit a ground monitoring report within 30 days of completing hydraulic fracturing operations.

In May 2018, the BCOGC issued a Special Project Order under section 75 of the OGAA, which designated the Kiskatinaw Seismic Monitoring and Mitigation Area, spanning between Fort St. John and Dawson Creek ("**Kiskatinaw Area**"). Permit holders in the Kiskatinaw Area are subject to additional requirements before they can conduct hydraulic fracturing operations, including developing a seismic monitoring and mitigation plan that is approved by the BCOGC, and notifying the BCOGC and local residents about planned hydraulic fracturing requirements. During active hydraulic fracturing operations, permit holders are required to deploy an accelerometer, have access to real-time seismicity readings and report such readings to the BCOGC on demand. If a seismic event occurs, permit holders will be subject to a sliding scale of obligations. The obligations range from reporting the earthquake and developing an approved protocol for subsequent earthquakes, to initiating such protocols, to suspending operations until permitted to resume by the BCOGC. Future earthquakes outside of the Kiskatinaw Area may trigger the introduction of similar requirements elsewhere in the province.

On November 28, 2019, the *Declaration on the Rights on Indigenous Peoples Act* ("**DRIPA**") became law in British Columbia. The DRIPA aims to align British Columbia's laws with the United Nations Declaration on the Rights of Indigenous Peoples ("**UNDRIP**"); however, it is unclear what the practical consequences of this law will be. The DRIPA also provides the Government of British Columbia with the authority to enter into decision-making and consent agreements with Indigenous groups which would allow those Indigenous groups to obtain new regulatory decision-making authority. The draft 2021-2026 Action Plan, which sets out the actions to be taken to implement the DRIPA, was released for public comment in June 2021. One of the action items in the draft Action Plan is the negotiation of decision-making and consent agreements.

An updated *Environmental Assessment Act* (British Columbia) came into force on December 16, 2019. The new assessment regime subjects proposed projects to an enhanced environmental review process that, among other things, emphasizes early engagement and aims to enhance Indigenous engagement in the project approval process with an emphasis on consensus-building and, at specific points in the process, consent. Simultaneously with the enactment of the *Environmental Assessment Act* (British Columbia), the Government of British Columbia enacted the accompanying Reviewable Projects Regulation, which sets out the projects subject to the new regime. The "project list" captures industrial, mining, energy, water management, waste disposal, transportation and other GHG intensive projects. In conducting an environmental assessment, the British Columbia Environmental Assessment Office ("**BCEAO**") will consider the environmental, health, cultural, social and economic effects of a proposed project. The new legislation also expands the scope for projects, which would otherwise not be reviewable, to be designated for review under the *Environmental Assessment Act* (British Columbia).

Liability Management Rating Program

Alberta

The AER administers a Liability Management Rating Program ("**AB LMR Program**") which governs most conventional upstream crude oil and natural gas wells, facilities and pipelines.

The AB LMR Program consists of three distinct programs: (a) the Licensee Liability Rating Program ("**AB LLR Program**"); (b) the Oilfield Waste Liability Program ("**AB OWL Program**"); and (c) the Large Facility Liability Management Program ("**AB LFP**"). If a licensee's cumulative deemed liabilities in the AB LLR Program, the AB OWL Program and the AB LFP exceed its deemed assets in those programs, the licensee must reduce its liabilities or provide the AER with a security deposit. Failure to do so may restrict the licensee's ability to transfer licences or result in enforcement action by the AER. The ratio of a licensee's assets to liabilities across the three programs is referred to as the licensee's LMR.

The AER previously posted individual Liability Management Ratios ("**LMRs**") on the AER's public website on a monthly basis. While the AER no longer posts individual LMRs on its website, licensees can access their individual LMR calculations through the AER's Digital Data Submission System.

Complementing the AB LMR Program, Alberta's OGCA establishes an orphan fund ("**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 the licensee or working interest participant of the facility becomes insolvent or is otherwise unable to meet its abandonment and reclamation obligations. Licensees in the AB LLR Program and AB OWL Program fund the Orphan Fund through an annual levy administered by the AER. A separate orphan levy applies to persons holding licences subject to the AB LFP. Collectively, these programs are designed to minimize the risks 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 Government of Alberta and/or the AER may make further changes to Alberta's liability management programs at any time. For example, on July 30, 2020, the Government of Alberta announced a new Liability Management Framework ("**AB LMF**") that will replace the AB LMR Program. Among other changes under the AB LMF, the AB LMR Program will be replaced with the Licensee Capability Assessment System, which is intended to be a more comprehensive assessment of corporate health that considers a wider variety of factors than those considered under the AB LMR Program. Importantly, the AB LMF will require companies operating in Alberta's crude oil and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations The AB LMF will be implemented through, among other things, a new AER Directive for Licensee Life-Cycle Management (currently in draft form) and amendments to existing AER Directives pursuant to which the AB LMR Program is currently administered. See "*Risk Factors – Risks Related to the Company – Security Deposits under Provincial Liability Management Programs – Alberta*".

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

British Columbia

The BCOGC oversees a Liability Management Rating Program ("**BC LMR Program**") similar to the AB LMR Program in Alberta, which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations, including with respect to abandonment and reclamation. Under the BC LMR Program, permit holders whose deemed liabilities exceed their deemed assets (i.e., an LMR of below a ratio of 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and will be subject to compliance and enforcement action by the BCOGC.

On April 1, 2019, a liability-based levy paid to the Orphan Site Reclamation Fund ("**OSRF**") replaced the orphan site reclamation fund tax paid by permit holders. Similar to Alberta's Orphan Fund, the OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the levy. The OGAA permits the BCOGC to impose more than one levy in a given calendar year.

A key focus of the BCOGC's Comprehensive Liability Management Plan is to increase the rate at which inactive well sites are returned to their pre-activity state. Effective May 31, 2019, the Dormancy Regulation establishes legislatively prescribed timelines for the restoration of crude oil and natural gas wells in British Columbia. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036. There are additional regulated timelines for sites that become dormant before 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BCOGC, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in the corresponding annual work plan.

Accountability and Transparency

In 2015, the Government of Canada's *Extractive Sector Transparency Measures Act* ("**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 $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 taxes), fees, production entitlements, bonuses, dividends (other than ordinary dividends paid to shareholders), infrastructure improvement payments and other prescribed categories of payments.

Power Industry

The construction and operation of power projects are subject to federal, provincial and/or local laws, rules, regulations and guidelines which are subject to governmental review and revision from time to time. Legislative regimes are generally in place to, among other things, ensure the reliability of electric systems and the exchange of electricity, safety, the protection of the environment and the regulation of land use. The laws, rules, regulations and guidelines that may become applicable to the Company primarily relate to the generation of electricity, the marketing and selling of electricity, the discharge of emissions into the water and air, waste disposal, water use, wetlands preservation, endangered species, and noise regulations, among other things. In many cases, such laws, rules, regulations and guidelines may also impose lengthy and complex processes for obtaining licences, permits and approvals from federal, provincial and local authorities.

Alberta

Since January 1, 1996, new generation capacity initiatives in Alberta have been paid for by independent power producers (subject to market forces), rather than rate payers. Regulated generating units became subject to PPAs arrangements that were auctioned by the Government of Alberta to buyers in 2000. The Alberta Balancing Pool ("**Balancing Pool**"), an Alberta provincial government entity established to, among other things, hold certain PPAs, assumed the responsibilities of "Buyer" for those generating units that were subject to a PPA not acquired in the initial 2000 auction.

Alberta's power market is monitored, and participant market behaviour is investigated where necessary, by the Market Surveillance Administrator ("**MSA**"). The MSA protects and promotes the fair, efficient, and openly competitive operation of Alberta's electricity market. It monitors the performance of the market to ensure that market participants comply with all applicable legislation, the Alberta Reliability Standards, and AESO rules. When AESO rules or reliability standards are violated, the MSA may issue penalties or request a hearing or other proceeding before the AUC pursuant to which an administrative penalty or other conditions may be imposed.

The AUC reviews applications for power generation facility developments to determine if facility sites are in the public interest and should be approved. When the AUC considers such developments it considers potential social, economic and environmental impacts, including noise, and the extent to which the concerns of local stakeholder have been addressed. Having regard to the deregulated nature of the electricity generation market in Alberta, the AUC does not have jurisdiction to direct the construction of power generation facilities including at specific locations in the province, or to assess whether a proposed generation facility is an economic source of power. The AUC is responsible for approving the AESO's rules and for adjudicating allegations of anti-competitive market behaviour in Alberta's wholesale electricity market.

In November 2016, the Government of Alberta announced that it would transition Alberta's electricity market design from an energy-only market to a capacity market. In July 2019, the transition was cancelled. Along with the cancellation, the Government of Alberta tasked the AESO to provide its advice on the existing market power mitigation framework and also whether changes to the existing market pricing framework were required. On April 23, 2020, the Government of Alberta announced acceptance the AESO's advice to maintain the current market power mitigation framework, and on August 28, 2020, announced acceptance of the AESO's advice to maintain the current pricing framework, including the existing offer cap, price cap, and price floor.

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 crude oil and natural gas industry in Canada. Any new laws and regulations (or additional requirements under existing laws and regulations) could have a material impact on the Company's operations and cash flow.

Federal

Canada has been a signatory to the United Nations Framework Convention on Climate Change ("**UNFCCC**") since 1992. Canada's involvement with the UNFCCC has prompted numerous policy developments with respect to climate governance. On April 22, 2016, parties to the UNFCCC, 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, 191 of the 197 parties to the UNFCCC have ratified the Paris Agreement, including Canada. In December 2019, the United Nations annual Conference of the Parties took place in Madrid, Spain. The Conference concluded with the attendees delaying decisions about a prospective carbon market and emissions cuts until the next climate conference, scheduled to take place in November 2021.

Pursuant to the Paris Agreement, the Government of Canada pledged to cut its emissions by 30% from 2005 levels by 2030 (however, as discussed in greater detail below, it has indicated that it may implement policy changes to exceed this target). In connection with this target, the Government of Canada released the Pan-Canadian Framework on Clean Growth and Climate Change ("**Framework**") in 2016. One of the components of the Framework is the introduction of federal carbon tax for those provinces and territories that do not already have an equivalent carbon pricing regime in place.

On June 21, 2018, the Government of Canada enacted the *Greenhouse Gas Pollution Pricing Act* ("**GGPPA**"), which introduced a carbon tax. This system applies in provinces and territories that request it and in those that do not have comparable emissions pricing systems in place that meet the federal standards. The effect of the GGPPA is that, regardless of whether a particular province has enacted carbon pricing legislation of its own, there is an equivalent price on emissions across the country. The GGPPA has two parts: an output-based pricing system which sets emissions intensity standards for large industry and a carbon levy for various types of fuel usage.

As of April 1, 2021, the carbon levy pursuant to the GGPPA is $40 per tonne of CO_2E, and it will increase to $50 per tonne in 2022. Although not yet law, in December 2020, the Government of Canada proposed that the carbon levy would increase by $15 per year beginning in 2022 up to $170 per tonne by 2030.

The proposed increase in carbon pricing in 2030 relates to the Government of Canada's commitment to exceed Canada's target under the Paris Agreement and achieve net-zero emissions by 2050. The *Canadian Net-Zero Emissions Accountability Act* (Canada), which formalizes the net-zero emissions by 2050 target was enacted on June 30, 2021. Such act legislates emissions reductions accountability by requiring the Government of Canada to plan and report on emissions reductions plans and to set reduction targets for 2035, 2040 and 2045 at least 10 years in advance.

The Government of Canada has indicated that it intends to make a number of investments that will help it achieve these targets, including (among other things) a Clean Power Fund that will support the electrification of Canadian industries and the transition of regions currently reliant on diesel power generation and continued investment in the development and implementation of renewable and clean energy technologies. Specific program details have not yet been announced.

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

The Government of Canada has enacted the Multi-Sector Air Pollutants Regulation under the authority of the *Canadian Environmental Protection Act, 1999* (Canada). Such regulation sets mandatory national emissions standards for nitrogen oxides and sulphur dioxide from certain industrial facilities and equipment types, including boilers and heaters used in the upstream crude oil and natural gas industry.

The Government of Canada has also proposed the Clean Fuel Regulations under the *Canadian Environmental Protection Act, 1999* (Canada). Pursuant to the Clean Fuel Regulations, fuel producers, importers and distributors will be required to reduce the emissions intensity of gaseous, liquid and solid fuels. A final version of the regulation is expected to be published in late 2021, and regulatory requirements will come into force in December 2022.

Alberta

Alberta had a carbon levy on fuel usage in place from 2017 until its repeal on May 30, 2019. Since that time, Alberta has been subject to the federal carbon levy provisions under the GGPPA.

However, Alberta is not subject to the output-based pricing system for large emitters under the GGPPA, because the Technology Innovation and Emissions Reduction Regulation ("**TIER**") satisfies federal requirements. Pursuant to the TIER, facilities that annually emit more than 100,000 tonnes of CO_2E are subject to emissions reduction requirements. Most facilities are subject to a facility-specific benchmark pursuant to which they must reduce emissions intensity by 10% when compared to their average emissions between 2016–2018, with the reduction requirement increasing by one per cent each year beginning in 2021. The facility-specific benchmark does not apply to all facilities. Facilities in the electricity sector are instead subject to a "good-as-best-gas" benchmark of 0.37 tonnes of CO_2E per megawatt-hour. For facilities that have already made substantial headway in reducing their emissions, a different "high-performance" benchmark is available to ensure that the cost of ongoing compliance takes this into account. Under the TIER, facilities in high-emitting sectors can opt-in to the program in specified circumstances despite the fact that 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 the required emissions reduction targets or meet the specified benchmark may purchase credits from facilities that have exceeded reduction targets, purchase Alberta-based emission offsets (e.g., from renewable electricity producers among others), or pay into the TIER Fund (at a rate of $40 per tonne of CO_2E in 2021).

The Government of Alberta has committed to reducing methane emissions from upstream oil and gas regulations by 45% relative to 2014 levels by 2025. To facilitate this goal, the Government of Alberta enacted the Alberta Methane Regulations, and directed the AER to develop complementary regulatory directives. The Alberta Methane Regulations require AER licensees to comply with AER Directive 060: Upstream Petroleum Industry Flaring, Incinerating, and Venting and AER Directive 017: Measurement Requirements for Oil and Gas Operations. 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.

British Columbia

The British Columbia *Climate Change Accountability Act* (British Columbia) establishes the provincial target of reducing emissions by 80% below 2007 levels by 2050.

The revenue neutral *Carbon Tax Act* (British Columbia) imposes a tax on consumption in British Columbia of virtually all fossil fuels, including gasoline, diesel, natural gas, coal and propane. The fuel charge increased from $40 to $45 per tonne of CO_2E on April 1, 2021, and is scheduled to increase to $50 per tonne of CO_2E on April 1, 2022.

The *Greenhouse Gas Industrial Reporting and Control Act* ("**GGIRCA**") establishes emissions performance standards for specified industrial sectors and regulated operations. Emission reporting obligations apply to a broader range of facilities pursuant to the GGIRCA's Greenhouse Gas Industrial Emission Reporting Regulation, including facilities that undertake specified oil and gas activities and emit over 10,000 tonnes of CO_2E annually. The GGIRCA's Greenhouse Gas Emission Control Regulation establishes a framework for the purchase of emissions offsets and the BC Carbon Registry through which offsets may be issued, transferred, or retired.

The Government of British Columbia's "CleanBC" clean energy plan includes a number of strategies targeting the industrial, transportation, construction, and waste sectors of the British Columbia economy. Key initiatives include: (a) increasing the generation of electricity from clean and renewable energy sources; (b) imposing a 15% renewable content requirement in natural gas by 2030; (c) requiring fuel suppliers to reduce the carbon intensity of diesel and gasoline by 20% by 2030; (d) investing in the electrification of crude oil and natural gas production; (e) reducing 45% of methane emissions associated with natural gas production; (f) developing a regulatory framework for carbon capture and underground storage; and (g) incentivizing the adoption of zero-emissions vehicles.

The BCOGC introduced a series of amendments to the British Columbia *Drilling and Production Regulation* to reduce methane emissions from upstream oil and gas operations which came into effect on January 1, 2020. The amendments enhance requirements for methane leak detection and repair, particularly with respect to storage tanks, surface casing, glycol dehydrators and other equipment that has been identified as a primary source of methane emissions in the upstream oil and gas sector. In February 2020, the Government of Canada and the Government of British Columbia entered an equivalency agreement regarding the reduction of methane emissions such that the Federal Methane Regulations will not apply in British Columbia.

RISK FACTORS

The following is a list of risks that the Company faces in its normal course of business. The risks and uncertainties set out below are not the only ones the Company is facing. There are additional risks and uncertainties that the Company does not currently know about or that the Company currently considers immaterial which may also impair the Company's business operations and cause the value of the Common Shares to decline. If any of the following risks actually occur, the Company's business may be harmed and the Company's financial condition and results of operations may suffer significantly.

Risks Related to the Company

Risks Associated with Developing and Operating the Power Generation and Renewable Energy Business

There can be no assurance that the Company will develop its integrated energy transition company strategy in the manner or within the timeframes currently anticipated or contemplated, including as set out in this AIF.

The Company's strategy for building an energy transition company is to develop high-quality natural gas and power generating facilities that are integrated with its upstream crude oil and natural gas business and that generate sustainable cash flows and provide an attractive risk-adjusted return on invested capital. However, there is no certainty that the Company will be able to develop high-quality power generating or renewable energy facilities at attractive costs to fulfill its business plan or supplement its growth. To date, the Company's power generation and renewable energy portfolio has focused principally on evaluation and development activities and the Company has no history operating such business upon which an investor can evaluate such business and performance and base its investment decision.

The successful execution of the Company's energy transition strategy requires careful timing and business judgment and access to the capital and other resources required to complete the development of power generation and renewable energy projects. The Company may underestimate the timing, costs and expertise necessary to bring such projects into commercial operation in a manner that supports its integrated energy transition strategy.

In the normal course, the Company is expected to regularly evaluate and consider, and may be engaged in discussions and negotiations with respect to, potential acquisition and investment opportunities that it believes may assist it in achieving its business and growth plans, and in connection therewith it may at any time have outstanding non-binding letters of intent or conditional agreements which individually or together may be material. There can be no assurance that any such discussions, negotiations, non-binding letters of intent or conditional agreements will result in a definitive agreement with respect to an acquisition or investment, and, if they do, what the terms or timing of such would be or that such acquisition or investment will be completed by the Company. If the Company does complete any such transaction, it cannot assure investors that the transaction will ultimately strengthen the Company's financial or operating results, prospects or competitive position or that it will not be viewed negatively by customers, securities analysts or investors. Such transactions may also involve significant commitments of the Company's financial and other resources including the completion of additional financings of equity or debt. Any such activity may not be successful in generating revenue, income or other returns to the Company and the resources committed to such activities will not be available to the Company for other purposes.

Further, a number of other factors related to the acquisition, development, construction and operation of power generation and renewable energy projects could adversely affect the Company's business, including:

(a) difficulties in identifying, obtaining and permitting suitable sites for new projects and failure to obtain all necessary rights to land access and use;

(b) changes in energy commodity prices, including wholesale electricity prices;

(c) substantial construction risks, including the risk of cost overruns and delays, including those that may arise as a result of material pricing, inclement weather, labour disruptions, performance by major counterparties, health, safety and environmental risks and/ or other extenuating events (such as COVID-19);

(d) regulatory risks affecting the Company's ability to obtain necessary permits and licences or to utilize any of the government subsidies, including the evolution of regulation in this area;

(e) unforeseen engineering and environmental problems;

(f) the ability of competitors, who may have more capital resources, experience and expertise than the Company with such projects, to develop, construct and operate such projects more efficiently on a faster schedule than the Company; and

(g) failure to obtain the necessary capital and financing on acceptable terms or at all.

Ability to Achieve Investment Objectives

If there is not sufficient demand for development of the regulatory framework for renewable energy, or if renewable energy projects do not develop or take longer to develop than the Company anticipates, the Company may be unable to achieve the Company's investment objectives. In addition, demand for renewable energy projects in the markets and geographic regions that the Company targets may not develop or may develop more slowly than the Company anticipates. Many factors will influence the widespread adoption of renewable energy and demand for renewable energy projects, including:

(a) cost-effectiveness of renewable energy technologies as compared with conventional and competitive technologies;

(b) performance and reliability of renewable energy products as compared with conventional and non-renewable products;

(c) fluctuations in economic and market conditions that impact the viability of conventional and competitive alternative energy sources;

(d) increases or decreases in the prices of oil, natural gas and electricity; and

(e) availability or effectiveness of government subsidies and incentives.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

Kiwetinohk makes acquisitions and dispositions of businesses and assets both in the ordinary course of business and more signification acquisitions and dispositions from time to time. Acquisitions of properties or companies are based in large part on engineering, environmental and economic assessments made by the acquirer, independent engineers and consultants. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, environmental restrictions and prohibitions regarding releases and emissions of various substances, future prices of oil, natural gas and power, and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves or life of other assets. Many of these factors are subject to change and are beyond the control of Kiwetinohk. All such assessments involve a measure of geologic, engineering, facility operations, environmental and regulatory uncertainty that could result in lower production and reserves or higher operating or capital expenditures than anticipated.

Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as Kiwetinohk's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of so that Kiwetinohk can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of Kiwetinohk, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Company.

Global Economic and Financial Conditions

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions (including as a result of the COVID-19 pandemic), have caused significant volatility to commodity prices. The demand for energy including electricity consumption and petroleum and natural gas sales, is generally linked to economic activities. If there were to be a slowdown in economic growth, an economic downturn or recession, or other adverse economic or political developments in North America or globally, there could be a significant adverse effect on global financial markets which would in turn impact energy and commodity prices and may negatively impact the Company's operations and cash flows.

Licences and Permits

The Company's operations require licences and permits from various governmental authorities that are subject to changes in regulation and operating circumstances. There is no assurance that Kiwetinohk will be able to obtain all the necessary licences and permits required.

In addition, the Company does not currently hold all the approvals, licences and permits required for the development of its power generating and renewable energy projects, including environmental approvals and permits necessary to construct and operate such projects. The failure to obtain or delays in obtaining all necessary licences, approvals or permits, including renewals thereof or modifications thereto, could result in construction of the Company's power generating and renewable energy projects being delayed or not being completed or commenced. There can be no assurance that any one such proposed projects will result in any actual operating facility.

Competition

The crude oil and natural gas industry is intensely competitive, and Kiwetinohk competes with other companies that have greater resources. Many of these companies not only explore for and produce oil, NGL and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. Their competitive advantages may negatively impact Kiwetinohk's ability to acquire prospective properties, develop reserves, acquire or build related infrastructure, attract and retain quality personnel and raise capital. These competitors may be better positioned to take advantage of industry opportunities and to withstand changes affecting the industry, such as fluctuations in oil, NGL and natural gas prices and production, the availability of alternative energy sources and the application of government regulation.

In addition, the Company will compete with other power companies, including utilities, independent power producers, private equity developers, international conglomerates and traditional energy companies, which may have greater expertise and financial and other resources for new business. The Company will compete with other power companies primarily for growth opportunities for access to transmission or distribution networks. The Company also competes with other power companies for the limited pool of personnel with requisite industry knowledge and experience. Any failures to successfully prevail in such competition will negatively affect the Company's long-term growth prospects.

Coronavirus (COVID-19)

In December 2019, COVID-19 was reported to have surfaced; on January 30, 2020, the WHO declared the outbreak a global health emergency; and on March 11, 2020 the WHO declared the outbreak of COVID-19 a global pandemic. The spread of COVID-19 has led to governments and companies to impose quarantines, travel restrictions and other public health safety measures.

At this point, the extent to which COVID-19 may continue to impact Kiwetinohk is uncertain; however, it is possible that COVID-19 may have a material adverse effect on general economic conditions as well as Kiwetinohk's business, results of operations and financial condition. If subsequent waves or additional variants of COVID-19 emerge which are more transmissible or cause more severe disease, or if other diseases emerge with similar effects, adverse impacts on the economy could occur.

Market Constraints and Access to Services and Equipment

The Company's financial and operational results can be significantly affected by low product pricing, lack of transportation, lack of access to electricity and hydrogen markets and customers, shortage of markets for new sources of upstream products from the WCSB, or any combination thereof. These risk factors are a subset of the global and continental energy market risks which are impacted by national and global politics, price wars, conflict, climate change initiatives, war, pandemics, changing political policy in energy producing regions, or other geopolitical events and circumstances. These and other factors can cause an over or under supply of petroleum products and energy products dramatically affecting product pricing and the financial results of the Company.

The inability to access midstream equipment and services, or the high costs associated with accessing such equipment or services, poses risks associated with getting the Company's oil, NGL and natural gas production to market. Further, the services that the Company requires to gather, process and deliver its products to market may be terminated, interrupted or subject to increased costs. The marketability of the Company's oil, NGL and natural gas production depends in part upon the availability, proximity and capacity of oil, NGL and natural gas pipeline, trucking and rail systems, as well as processing facilities, some of which are owned by third parties. If any of the third-party transportation systems, such as the Alliance Pipeline or the Pembina Peace Pipeline, become partially or fully unavailable to transport or process the Company's products, or if quality specifications or physical requirements such as compression are altered by such third parties so as to restrict the Company's ability to transport its products on those pipelines or facilities, the Company's revenues could be adversely affected.

Crude oil and natural gas exploration and development activities are dependent on the availability of drilling, completion, transportation and related equipment as well as experienced and competent crews in the particular areas where such activities will be conducted. Demand for equipment or access restrictions may affect the availability of such equipment or crews to the Company and may delay or increase the cost of exploration and development activities. Operating and development costs are affected by a number of factors including price inflation, scheduling delays and access to skilled labour. The difficulties encountered by midstream proponents in Western Canada to obtain the necessary approvals on a timely basis to build pipelines, liquefied natural gas plants and other facilities to provide better access to markets for the crude oil and natural gas industry has led to additional downward pressure on crude oil and natural gas prices which has further reduced confidence in the crude oil and natural gas industry in Western Canada. These factors could result in a material decrease in expected net production revenue and a reduction in crude oil and natural gas acquisition, development and exploration activities. Any substantial and extended decline in the price of crude oil and natural gas would have an adverse effect on the Company's ability to carry out its business plan, reduce the value of its assets, and decrease profitability.

Additionally, certain contractual counterparties may have onerous credit requirements that are difficult for the Company to meet, resulting in an inability of the Company to obtain access to required equipment and services.

Furthermore, the Company's construction, development and operation of power generating facilities will be dependent on the supply of equipment from third parties. Equipment pricing may rapidly increase depending, among other things, on equipment availability, raw material prices and on the market for such products. Any significant increase in the price of supply of equipment could negatively affect the profitability of the Company's future facilities and the Company's ability to develop its projects.

Poor Performance of Properties

The Company may encounter geological hazards which reduce the performance of wells. This includes the wellbore encountering faults or water saturated zones in a geological region that is not as rich in liquids or gas as the optimal range that was targeted. Until further drilling results become available, there remains a material probability that individual well results may perform below expectations, which may negatively impact the results of the Company.

Adaptation and Extension of Existing Technology

The Company's strategy to increase the value from acquired oil, NGL and natural gas assets and to develop its portfolio of power generation assets includes plans to apply, adapt and extend existing technology. These efforts may, in time, turn out to be economically unattractive and leave the Company with a loss on investment, steering the Company back to present industry practices that represent the best it can achieve. As such, any plans to achieve the full economic potential of a region while managing capital aimed at risked upside, or to develop power generations assets, has yet to be proven by the Company and contributes a substantial risk to the value of the Company.

Possible Shortage of Fresh Water and Surface and Groundwater Licences

Drilling and completion operations require a large amount of water. The surface water resources of some of the regions where the Company aspires to operate may be insufficient for the full commercial scale development of the region at a pace matching the industry's ambitions. Thus, limitations on water access may present a ceiling on the allowed pace of development. This ceiling may take the form of a physical ceiling supported by scientific investigation, or it may be a limitation the Company chooses to accept to abate public concerns despite contradicting scientific evidence of the carrying capacity of the surface water resources. As a result, the Company may be required to develop alternatives to freshwater use as a hydraulic fracture fluid. These alternatives may include deep potable or brackish ground water, brine water produced in conjunction with oil and gas in the region, or a foam consisting of roughly 80% compressed methane and 20% fresh water.

Furthermore, there can be no assurance that the Company's governmental licences to withdraw water will not be rescinded or that additional conditions will not be added to these licences. Further, there can be no assurance that the Company will not have to pay a fee for the use of water in the future or that any such fees will be reasonable. Finally, new projects or the expansion of existing projects may be dependent on securing licences for additional water withdrawal, and there can be no assurance that these licences will be granted on terms favourable to the Company, or at all, or that such additional water will in fact be available to divert under such licences.

Exploration, Development and Production Risks

Crude oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Company depends on its ability to find, acquire, develop and commercially produce crude oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in the Company's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Company will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, the Company may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of crude oil and natural gas will be discovered or acquired by the Company.

Future crude oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but from wells that are productive but do not produce sufficient net revenues to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. The Company may experience issues with drainage or devaluation of lands by offsetting competitor wells. Certain wells may deteriorate in performance due to offset drainage of the region before extension wells can be drilled. In addition, some of Distinction's past field planning practices may affect third party assessments of the Company's asset value or future profitability. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. Crude 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 hazards such as fire, explosion, blowouts, cratering, liner failures, sour gas releases and spills and other environmental hazards, each of which could result in substantial damage to crude oil and natural gas wells, production facilities, other property and the environment or in personal injury or fatalities. The Company's operations may cause or initiate environmental damage such as forest fires or damages to roads.

Significant Factors or Uncertainties Affecting Reserves Data

In the development of any region of any low permeability formation, it has been the industry's experience that the productivity and ultimate recovery of new wells can be adversely affected by the existence and proximity of previous wells. The industry term for this phenomenon is "Parent-Child effects". To the best of the Company's knowledge, the industry has struggled to build a reliable, comprehensive mathematical model of the flow of gas, natural gas liquids, oil and water from points in a resource body to hydraulic fractures, the well bore and to surface. Because the physics is too complex to reliably model, forecasting is generally done by statistical comparison. Forecasters seek a prediction by comparing control data from actual production data and ultimate recovery projections derived therefrom for existing wells to the control data for prospective well locations. In these comparisons, forecasters may use:

(a) natural control data such as petrophysical and geomechanical data derived from well logs and cores and pressure surveys; and

(b) well and development design control data, including, but not limited, to horizontal well spacing, horizontal lateral length, number of fracturing fluid entry points per pumped fracture, number of fracture stages per well, amount of fluid and amount of proppant per frac and per unit of lateral length, proppant concentration in the fracture slurry, slurry pump rate and total volume.

This method of forecasting includes risks and limitations, such as resource properties varying between locations and the state of the resource at any location being altered by previous activity. The Parent-Child phenomenon is the observation that pre-existing wells, within some unknown and unpredictable spacing sometimes appear to deleteriously affect the production rate and recovery of offsetting wells. In addressing this risk, the Company's plans would generally include using wider than previously used well spacing as well as the pursuit of better performance by rigorous study of the effects of, and experimentation with, adjustment of well and development design and control parameters. Historically, Kiwetinohk has from time to time and project to project used the services of consultants with advanced data analysis methods to provide independent views on the effect of well and development design and control parameters on recovery, production rate and development economics.

Drilling Risks Associated with Unconventional Oil and Gas

Drilling for unconventional oil, NGL and natural gas, stimulating well productivity and production of unconventional oil, NGL and natural gas resources pose operating risks different from conventional oil, NGL and natural gas production operating risks, including:

(a) higher capital costs than similar depth conventional natural gas wells because of necessary alternative drilling or completion techniques, water production, treatment, transportation and disposal costs, additional compression, and other factors;

(b) relatively long pilot production test times to determine commerciality or optimal practices, as compared to conventional crude oil and natural gas fields;

(c) peak production rates, time to reach peak rate, and time that peak rate can be sustained, are subject to substantially greater uncertainty for unconventional crude oil and natural gas wells than conventional crude oil and natural gas wells;

(d) difficulties associated with producing water, including scale formation, corrosion or backpressure caused by inefficient pumping, restrictions on surface facilities capacity, failure of water disposal wells to adequately handle required volumes of produced water and related dewatering;

(e) difficulties associated with extreme weather conditions including potential freezing;

(f) more wells per section in some instances than is possible to optimally and cost-effectively develop reserves;

(g) reduced wellhead pressures needed for production, leading to larger flow lines or additional compression;

(h) complexity of development of multiple productive zones; and

(i) failure to realize anticipated benefits from the application of unconventional drilling techniques.

Historical Liabilities

While Distinction's CCAA proceedings were intended to cleanse any historical liabilities relating to the assets of Distinction, there is no guarantee that contractual counterparties will not continue to assert rights or claims that arose prior to such time. If any of the Company's contractual counterparties continue to assert such rights or claims, it could have a material adverse impact on the Company's finances and business reputation, affecting its ability to contract services and equipment at competitive prices, operating results, financial condition, cash flow and liquidity. Especially where joint and several liability exists, some creditors may pursue recovery of their losses through the CCAA process, affecting the Company's business relationship with its partners.

Hydraulic Fracturing and Earthquakes

Occasional minor earthquakes in some of the oil and gas shale development regions have been attributed to hydraulic fracturing operations. The Government of Alberta has regulations prescribing conditions in which an operator is either free to monitor and continue to fracture or is obligated to suspend operations. While it is unlikely that any earthquake attributed to the Company's operations would be in a location or of an intensity that it would cause significant loss to other parties, it is possible that the Company's value realization aspirations for its undeveloped land holdings in a region could be lost in whole or in part.

Impaired Oil and Gas Operating or Social Licence

The Company will engage with the communities where its assets are located so that community members feel a shared sense of ownership and pride in the success of the Company and its projects. Notwithstanding engagement strategies and local benefits, stakeholder objections can result in delayed surface access and/or regulatory approvals, or the need to select alternative locations. This may be especially true in areas such as the Central Alberta West Duvernay basin where water is not as readily available and housing density is high. Delays could result in land expiring before it can be sufficiently evaluated and developed. Further, certain landowners may elect to not grant surface rights or lease roads or land of the Company, or may only agree to do so at prohibitively high rates.

In addition, the social acceptance by local stakeholders, including, in some cases, First Nations and other Indigenous peoples, and local communities is critical to our ability to find and develop new sites suitable for viable power generation and renewable energy projects. Failure to obtain proper social acceptance for a project may prevent the development and construction of a project and lead to the loss of all investments made in the development and the write-off of such prospective project.

Regulatory Non-Compliance

The Company could face penalties or other liabilities or sanctions due to past non-compliance with environmental laws, including regulatory reporting requirements. Non-compliance with laws or regulations may result in fines, penalties, cancellation or rejection of permits, shutdown of operations and/or litigation. Any such liability with respect to the Company's production activities could materially adversely affect the Company's reputation and financial condition and results of operations.

Crown Land Tenure Obligations, Interpretations and Freehold Offset Royalty Obligations

There is a risk that the government imposes the strictest interpretation of land tenure regulations and terminates a high percentage of leases on expiry. On the freehold side, as the Company develops an oil quarter, quarter sections or sections of adjacent land without wells would require the payment of an offset royalty in order to continue than land. In addition, drilling of wells adjacent to undrilled freehold leases can trigger an obligation to drill the undrilled lands or pay a royalty on those lands equivalent to what would be expected if a well was operating on those lands, or it is our choice to allow the freehold leases to expire. As such, royalty estimates may significantly change in the future. In addition, many of the crude oil and natural gas leases in the West Central Alberta Duvernay have been issued earlier this decade and are coming up for expiry in the near to medium-term. As a result, the Company must drill wells with less information and evaluation time between wells in order to maximize the amount of land that can be retained. However, moving too quickly could possibly expose the Company to an undesirable level of risk. The Company plans to pursue a strategy of acquiring high grade land and drilling the land that appears to have the most favorable geological characteristics, while testing well designs that have the potential to yield substantially improved economics. As a result, the Company may allow less prospective land to expire which would reduce the Company's overall land position.

Unforeseen Title Defects

Ownership of some of the Company's properties could be subject to prior undetected claims or interests. The Company plans to conduct title reviews from time to time according to industry practice prior to the purchase of most of its crude oil and natural gas producing properties or the commencement of drilling wells. However, title reviews, if conducted, do not guarantee that an unforeseen defect in the chain of title will not arise to defeat a claim by the Company. If any such defect were to arise, the Company's entitlement to the production and reserves associated with such properties could be jeopardized, and could have a material adverse effect on the Company's financial condition, results of operations and the Company's ability to timely execute its business plan. Indigenous peoples have claimed title and rights to portions of Western Canada. The Company is not aware of any claims that have been made in respect of its property and assets; however, if a claim arose and was successful, this could have an adverse effect on the Company and its operations.

Drilling Failure or Loss of Control of a Well

The Central Alberta Duvernay formation is naturally fractured with high formation pore pressure. This degree of pressure poses a containment problem related to any mechanical or equipment failures during drilling and completion operations which may cause the loss of the ability to finish drilling, completing, equipping and producing operations. As a consequence, this may result in a loss of investment. This potential problem is especially a risk should the Company be part way through the frac process at a time in which the well might have the capacity to flow back brine and hydrocarbons.

Insurance Coverage

The Company maintains, and the Company will maintain, insurance coverage as part of its risk management program. However, such insurance may not provide comprehensive coverage in all circumstances and not all risks are insurable. The Company will renew its insurance policies 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 the Company to decide to reduce or possibly eliminate certain insurance 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. The overall risk exposure and cost of insurance could significantly change in the future if coverage is not available.

Carbon Taxes and Environmental Compliance Costs

The crude oil and natural gas industry is subject to environmental regulation pursuant to municipal, provincial and federal legislation. Such legislation may be changed to impose higher standards and potentially more costly obligations to the Company. Policies aimed at reducing emissions of CO_2 and methane could become a burden on crude oil and natural gas commodities relative to other sources of energy in the marketplace. Furthermore, there is no assurance that any such programs or regulatory amendments, if proposed and enacted, may contain emission reduction targets that the Company can meet. Financial penalties or charges could be incurred as a result of the failure to meet such targets.

Access to Capital Markets and Ability to Sell and Recover Capital

Capital and credit markets have experienced volatility and disruption and continue to be unpredictable. The Company's capital expenditures relating to its upstream business and future development and construction of power generating projects may be financed out of cash generated from borrowing or the issuance and future equity issuances. The ability to issue equity is dependent upon, among other factors, the overall state of capital markets and investor appetite for investments in the energy industry, and the Company's differentiated business model, including having superior quality and attractive acquisition opportunities as compared to the rest of the industry. Additionally, crude oil and natural gas producers and companies in heavy carbon emitting industries may experience an increased cost of capital due to climate change policies or the size of the Company may impact its cost of capital. To the extent that external sources of capital become limited, unavailable, or available on onerous terms, or the Company cannot exit projects and find a buyer, the Company's ability to make capital investments and develop projects to execute on its business plan may be challenged.

There is no certainty that sufficient capital will be available on acceptable terms to fund the Company's capital expenditures associated with its upstream business or development and construction of its power generating projects. There are numerous renewable energy projects to be constructed in the coming years that will result in competition for capital.

Access to Credit Facilities

The Credit Agreement imposes operating and financial restrictions on the Company as to activities around future acquisitions, dispositions, incurring additional indebtedness, capital expenditures or entering into amalgamations, mergers or take-over bids. If the lenders require repayment of any or all of the amounts outstanding under the Credit Agreement, there is no certainty that the Company would be in a position to make such repayment. Additionally, oil and gas producers and companies in heavy carbon emitting industries may experience an increased cost of capital due to climate change policies or the size of the Company may impact its cost of capital. If the Company cannot obtain new financing, or it is not available on commercially reasonable terms, the banks may proceed to foreclose or otherwise realize upon their secured debt.

Need to Differentiate in a Well-Established Industry

Barriers to entry within the electrical power industry contribute to both the current attractiveness and the immediate risk of this business. The barriers to entry may work against the Company in the short term and their removal in the mid- to long-term may cause the business to be overwhelmed with competition. With increased competition, the Company may not be able to secure or finance preferred projects at an attractive valuation.

Retention of Key Personnel

The successful operation of the Company's business and its ability to expand operations will depend upon the availability of, and competition for, skilled labor. The Company's success depends in large measure on certain key personnel. A loss in any of the key personnel of the Company could delay the completion of certain projects or otherwise have a material adverse effect on operations. As an early-stage company seeking to differentiate with the skills of specialized experts, the Company may lack redundancy in certain areas of expertise and as a result the Company may suffer greatly from the loss of key personnel. In addition, it is not anticipated that the Company will maintain "key person" life insurance policies on any of its employees. As a result, the Company will not be insured against any losses resulting from the death of its key employees. The competition for qualified personnel in the crude oil and natural gas industry is intense and there can be no assurance that the Company will be able to continue to attract and retain all personnel necessary for the development and operation of its business.

Acquisitions and Growth Projects

The price paid for acquisitions is based on engineering and economic estimates of the potential reserves made by independent engineers modified to reflect the technical views of management. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of oil, natural gas, and NGL, future prices of oil, natural gas and NGL, operating costs, future capital expenditures and royalties and other government levies that will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of management. Changes in the prices of, and markets for oil, natural gas, and NGL from those anticipated at the time of making such assessments will affect the value of the Common Shares. In addition, all such estimates involve a measure of geological and engineering uncertainty that could result in lower production and reserves. Actual reserves and anticipated benefits from acquisitions could vary materially from these estimates. Further, if the various regulatory approvals and conditions to close are not met, the Company will not be able to achieve the anticipated benefits of the acquisition.

In addition, expansion of the Company's power generation and renewable energy business through development and construction projects and acquisitions may place increased demands on management, operating systems, internal controls and financial and physical resources. In addition, the process of integrating acquired businesses or development and construction projects may involve unforeseen difficulties. Failure to successfully manage or integrate any acquired businesses or development and construction projects could have a material adverse impact on the Company's financial condition, results of operations and cash flows.

With respect to acquisitions, there can be no assurance that the Company will identify suitable transactions or that it will have access to sufficient resources, through the capital markets or otherwise, to pursue and complete any identified acquisition opportunities on a timely basis and at a reasonable cost. Any acquisition that the Company proposes or completes would be subject to normal commercial risks that the transaction may not be completed on the terms negotiated, on time, or at all. An unavoidable level of risk remains regarding potential undisclosed or unknown liabilities relating to any acquisition. The existence of such undisclosed liabilities may have a material adverse impact on the Company's business, financial condition, results of operations and cash flows.

Indigenous Land Claims and Stakeholder Opposition

Indigenous peoples have established and claimed Indigenous rights and title in portions of Western Canada. Claims of Indigenous peoples and protests and demonstrations pertaining to Indigenous rights and title may disrupt or delay third-party operations or new development on the Company's properties. Requirements relating to the federal implementation of the UNDRIP, including the UNDRIP concept of free, prior and informed consent before adopting measures or approving projects that may affect Indigenous peoples, have the potential to adversely affect the Company's ability to obtain permits, leases, licences and other approvals, or to meet the terms and conditions of those approvals.

The Company is not aware that any claims have been made by Indigenous peoples in respect of its assets; however, if a claim arose and was successful this could have an adverse effect on the Company and its operations. Additionally, opposition may occur from stakeholders, or there may be an expectation of compensation or consideration associated with a project beyond historical levels. The process of addressing Indigenous and stakeholder claims, regardless of the outcome, can be expensive and time-consuming and could result in delays which could have a negative effect on the Company's business, financial condition, results of operations and prospects, which negative effect could prove to be material over time.

Seasonality

The level of activity in the Canadian crude oil and natural gas industry is influenced by seasonal weather patterns. A mild winter or wet spring may make the ground unstable, limit access and, as a result, cause reduced operations or a cessation of operations. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain crude oil and natural gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. In addition, extreme cold weather, heavy snowfall and heavy rainfall may restrict access to the Company's properties and cause operational difficulties including damage to machinery or contribute to personnel injury because of dangerous working conditions. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity and also to volatility in commodity prices as the demand for natural gas typically varies during the year depending on weather (higher during the cold winter months and hot summer months). There can be no assurance that these seasonal factors will not adversely affect the timing and scope of the Company's exploration and development activities, which could in turn have a material adverse impact on the Company's business, operations and prospects.

Extreme Weather Conditions

In addition to climate policy risk, the industry faces physical risks attributable to a changing climate. Extreme hot and cold weather, heavy snowfall, heavy rainfall and wildfires may restrict the Company's ability to access the Company's properties and cause operational difficulties, including damage to machinery and facilities. Extreme weather may also increase the risk of personnel injury as a result of dangerous working conditions. Certain of the Company's assets are located in locations that are proximate to forests and grasslands, and a wildfire may lead to significant downtime and/or damage to such assets. Moreover, extreme weather conditions may disrupt the Company's ability to transport produced natural gas and NGL as well as goods and services along the supply chain.

Wildfires

Wildfires are an unpredictable risk depending on the unique combination of rain, lightning, and wind each spring, summer, and fall that could damage the Company's infrastructure, limit access and, as a result, also lead to reduced operations or a cessation of operations.

Government Regulation

All phases of the energy business present environmental risks and hazards and are subject to environmental and other project regulation pursuant to a variety of federal, provincial and municipal laws. Environmental legislation provides for, among other things, restrictions and prohibitions on the spill, release or emission of various substances produced in association with crude oil and natural gas industry operations. Compliance with environmental legislation can require significant expenditures and a breach of such legislation may result in the imposition of fines or other penalties, some of which may be material, as well as the responsibility to remedy environmental problems caused by the Company's operations. Any new laws, regulations or permitting requirements regarding oil sands development or fossil fuel activity could lead to operational delays, increased operating costs or third-party or governmental claims, and could also increase the Company's compliance costs and delay the development of the Company's oil, NGL and natural gas resources. Restrictions on oil sands development and fossil fuel activity could also reduce the amount of oil, NGL and natural gas that the Company is ultimately able to produce from its reserves.

The Company's operations and activities will emit GHGs, which will require the Company to comply with GHG emissions legislation at the provincial and federal levels. Concerns over climate change, production and consumption of fossil fuels, GHG emissions and water and land-use practices is leading to climate change policy that is evolving at regional, national and international levels. In addition, political and economic events may significantly affect the scope and timing of climate change policies that are put in place. Some of the Company's facilities may be subject to future changes to regional, provincial and/or federal climate change regulations to manage GHG emissions which could significantly increase operating and development costs.

Additionally, the renewable energy sector is subject to extensive government regulation. The market for the Company's power generation is heavily influenced by Canadian government regulations and policies, which often relate to the encouragement of renewable energy development, electricity pricing and interconnection. These regulations are subject to change based on the current and future economic or political conditions.

Unforeseen Liabilities and Circumstances

The Company may from time to time discover unforeseen circumstances and liabilities. These unforeseen issues may be exacerbated by the Company's novel assets. Potential unforeseen issues may include, but are not limited to, the following: (a) discovery of liabilities; (b) claims by third parties for equipment or services; (c) discovery of undisclosed spills, contamination, or non-compliance issues; and (d) the discovery of non-compliance circumstances that result in a penalty.

The discharge of oil, natural gas, or other pollutants into the air, soil or water may give rise to liabilities to third parties and may require the Company to incur costs to remedy such discharge in the event that they are not covered by the Company's insurance. Although the Company will maintain insurance to industry standards, which in part covers liabilities associated with discharges, it is not certain that such insurance will cover all possible environmental events, foreseeable or otherwise, or whether changing regulatory requirements or emerging jurisprudence may render such insurance of little benefit.

Restrictions on Drilling Activities to Protect Wildlife

Crude oil and natural gas operations in the Company's operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit the Company's ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay the Company's operations and materially increase the Company's operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where the Company operates as threatened or endangered could cause the Company to incur increased costs arising from species protection measures or could result in limitations on the Company's exploration and production activities that could have an adverse impact on the Company's ability to develop and produce its reserves.

Additionally, some of the Company's producing areas are or will be located in areas that may become inaccessible due to environmental protection requirements. This includes, but is not limited to, protected caribou habitat on a seasonal basis.

Reduction, Elimination or Expiration of Government Subsidies

The Company may seek to take advantage of government policies that promote renewable power generation, enhance the economic feasibility of renewable power projects and encourage carbon reductions from energy production overall. Renewable power generation sources currently benefit from various incentives in the form of feed-in tariffs, rebates, tax credits and other incentives throughout the markets in which the Company participates or intends to participate. The removal or phasing out of any such policies or laws could adversely affect the viability of certain of the Company's expected growth initiatives, and could adversely affect the Company's results of operations, financial condition and cash flows.

Uncertainty of Development and Construction Projects

The Company's portfolio includes development and construction projects. As a result, the assumptions and estimates regarding the performance of these projects are and will be made without the benefit of a meaningful operating history. New power generating facilities have greater uncertainty surrounding their feasibility, social acceptance and future profitability than existing facilities with established track records. In certain cases, many factors affecting costs are not yet determined. The Company may, in some cases, be required to advance funds and post-performance bonds during development of its new facilities.

The ability of such projects to be completed or perform as expected will also be subject to risks inherent in newly constructed generation and transmission projects, including, but not limited to, equipment performance below the Company's expectations, unexpected component failures and product defects, and generation and transmission system failures and outages. The failure of some or all of the projects to perform as expected could have a material adverse effect on the Company's business, results of operations, financial condition and cash flows.

Project Risks

The Company will manage a variety of small and large projects in both its upstream crude oil and natural gas and power generation businesses. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Company's ability to execute projects and market electricity, crude oil and natural gas depends upon numerous factors beyond the Company's control, such as the effects of inclement weather, availability of equipment and resources, unexpected cost increases, accidental events, changes in regulations, and availability and productivity of skilled labour. Because of these factors, the Company could be unable to execute projects on time, on budget, or at all, and may be unable to market the electricity or crude oil and natural gas that the Company produces. It may be necessary to change the Company's development or drilling schedule, which could lead to negative reactions from service providers and other stakeholders. The Company may also experience adverse financial impacts related to take-or-pay in certain third party agreements.

A number of other factors related to the development and operation of clean energy projects could adversely affect the Company's business, including the consent and authorization of local utilities or other energy development off-takers to ensure successful interconnection to energy grids to enable power sales. Power grids may become overloaded with solar power during peak sunlight hours resulting in gas-fired power becoming uneconomical during those times or an insufficient market for power projects.

Transportation and Processing Commitments

The Company will from time to time enter into transportation and processing commitments in order to meet and satisfy future requirements from forecast production. If the production forecasts are not realized and the Company cannot satisfy these fixed transportation and processing commitments, there will be an underutilized demand charge which may negatively impact operating cash flows. Additionally, the Company may experience a lack of replacement gas to satisfy transportation commitments.

Hedging and Risk Management Contracts

From time to time, the Company may enter into agreements to receive fixed prices on its crude oil and natural gas production to offset the risk of revenue losses if commodity prices decline. Similarly, the Company may enter into agreements to fix the differential or discount pricing gap which exists, and may fluctuate between different grades of crude oil, NGL and natural gas and the various market prices received for such products. However, if commodity prices or differentials increase beyond the levels set in such agreements, the Company may be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk and the Company may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Conversely, if the Company enters into hedging arrangements to fix the cost of supply of its natural gas for electricity production, it may suffer losses if the market prices for natural gas decline as compared to the Company's contracted price.

In addition, if the Company enters into hedging arrangements, it may be exposed to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes or prices fall significantly lower than projected; there is a widening of price-basis differentials between delivery points for production and the delivery point assumed in the hedge arrangement; the counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements; and/or a sudden unexpected material event impacts crude oil and natural gas prices.

The Company will from time to time enter into other physical or financial agreements around commodity prices, foreign exchange rates or interest rates. Entering into such contracts may create additional financial loss in certain circumstances including inadequate production to cover contracted volumes, widening price-basis differentials on delivery points, counterparty failure to perform under the agreement, or sudden and unexpected impacts to pricing.

Drilling Activities May Encounter Sour Gas

A significant portion of the natural gas produced in Alberta originates as sour gas. With the inclusion of wellhead treatment facilities, the Company's infrastructure may, from time to time, encounter concentrations of sour gas. If a well encounters a high concentration of sour gas it would have to be shut-in due to the lack of existing sour gas handling infrastructure. Sour gas leaks or other exposure to sour gas produced from the Company's properties may result in damage to equipment, liability to third parties, adverse effects to humans, animals or the environment, or the shutdown of operations. Special equipment and operating procedures are deployed by the industry for the production of sour gas in accordance with applicable regulatory requirements.

Unanticipated Capital Costs

The Company's actual capital costs, operating costs and economic returns may differ significantly from the estimates contained in this AIF, the 2020 Reserves Reports, the 2021 Pro Forma Reserves Report and other studies or estimates prepared by or for Kiwetinohk. For example, the Company may not succeed at reducing its well costs in the future, the Company's capital costs to further develop its upstream properties and power generation projects may be significantly higher than anticipated or the ultimate returns from its wells may be significantly lower than expected. There can be no assurance that the Company's actual operating costs will not be higher than currently anticipated. If the Company's actual costs are higher than its current estimates this may adversely affect the Company's financial position, results of operations and cash flows.

Capital Resources

The Company will operate in a capital-intensive industry with medium- to long-term cash cycles. The Company will face lengthy development lead times, as well as risks associated with rising capital costs and timing of project completion because of the availability of resources, permits and other factors beyond its control. The Company's liquidity will primarily depend on its ability to generate cash flows from its operations and to obtain external financing to meet its debt obligations as they become due, as well as the Company's future operating and capital expenditure requirements.

Negative Public Perception

Development of the Alberta oil sands, crude oil and natural gas development and transportation, hydraulic fracturing and fossil fuels have figured prominently in recent political, media and activist commentary on the subject of climate change, GHG emissions, water usage and environmental damage. Concerns over heightened GHG emissions and water and land use practices may directly or indirectly reduce the profitability of the Company's current projects and/or the viability of all future hydrocarbon projects leading to a reduction in the demand and pricing of the Company's products. The Company's corporate reputation may be negatively affected by the negative public perception and public protests against crude oil and natural gas development and transportation and hydraulic fracturing.

Negative public or community response to wind, solar and gas power facilities and/or energy infrastructure assets could adversely affect our ability to operate the Company's power generation and renewable energy projects. This type of negative response could lead to legal, public relations and other challenges that impede the Company's ability to meet its development and construction targets, achieve commercial operations for a facility on schedule or generate revenues. While public opposition is usually of greatest concern during the development stage of renewable assets, which is when the public has the ability to provide comments and appeal regulatory permits, continued opposition could have an impact on operations. An increase in opposition to our requests for permits or successful challenges or appeals to permits issued to us could materially adversely affect the Company's plans. Legal requirements, changes in scientific knowledge and public complaints could impact the operation of certain of the Company's renewable assets in the future.

Climate Change

Public support for climate change action has grown in recent years, and has provided the impetus to pursue new technologies to mitigate the effects of climate change. Governments in Canada and around the world have responded by adopting ambitious emissions reduction targets and supporting legislation, including measures relating to carbon pricing, clean energy and fuel standards, and alternative energy incentives and mandates. Climate change related risks are typically grouped into two categories: transitional risks and physical risks. Transitional risks are broader and generally describe those risks related to the consequences of a global transition to reduced carbon. Specifically, transitional risks encompass risk of regulatory and policy changes, reputational risks, market risks, technology risks and market risks. Physical risks are those that a change in climate could have on the Company's business (as a result of a fire or flooding, for example).

In addition, variability in wind regimes and solar irradiation and their predictability may be affected by unforeseen climate changes, such as hurricanes, wind storms, hailstorms, rainstorms, floods and severe winter weather and forest fires, and may affect the amount of energy generated by the Company's future renewable projects. To the extent weather conditions are affected by climate change, the Company's future renewable power generation could increase or decrease depending on the duration and magnitude of the changes. The Company may also be unable to realize its carbon sequestration ambitions.

Growth Management

The Company may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The Company's ability to manage growth effectively will require it to continue to implement and improve its operations and financial systems and to expand, train and manage its employee base. The Company's inability to deal with this growth could have a material adverse impact on its business, operations and prospects.

Estimates May Vary from Actual Production

There are numerous uncertainties associated with estimating quantities of proved reserves and probable reserves and in projecting future rates of production and timing of expenditures. The reserves information herein represents estimates prepared by McDaniel and GLJ with respect to certain of the Company's oil, NGL and natural gas properties. Petroleum engineering is not an exact science. Information relating to oil, NGL and natural gas reserves and resources is based upon engineering estimates which may ultimately prove to be inaccurate. Estimates of economically recoverable oil, NGL and natural gas reserves and resources and of future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, assumptions concerning commodity prices, the quality, quantity and interpretation of available relevant data, future site restoration and abandonment costs, the assumed effects of regulations by governmental agencies and assumptions concerning future oil, NGL and natural gas prices, future operating costs, royalties, severance and excise taxes, capital investments and workover and remedial costs, all of which may vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil, NGL and natural gas attributable to any particular group of properties, classifications of such reserves and resources based on risk of recovery and estimates of the future net cash flows expected therefrom prepared by different evaluators or by the same evaluators at different times may vary substantially. Actual production, revenues and expenses with respect to the Company's reserves and resources will likely vary from estimates, and such variances may be material. In particular, there can be no assurance that the Company will achieve its own or the McDaniel and/or GLJ production estimates in future years. Wells drilled in the same fashion in the same formations in proximity to type-wells that were used in the Company's type-curve forecasts may not deliver similar production results, including liquids yields.

Abandonment and Reclamation

The Company will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which may result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of the Company's approvals and legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial and, while the Company accrues a reserve in its financial statements for such costs in accordance with IFRS, no assurance can be given that such accruals will be sufficient. It is not possible at this time to estimate abandonment and reclamation costs reliably since they will, in part, depend on future regulatory requirements. In addition, in the future, the Company may determine it prudent or be required by applicable laws, regulations or regulatory approvals to establish and fund one or more reclamation funds to provide for payment of future abandonment and reclamation costs. If the Company establishes a reclamation fund, its liquidity and cash flow may be adversely affected.

Third Party Claims

Claims made by third parties regarding the Company's rights to use the techniques and equipment that the Company employs could, among other things, delay or prevent the exploration or development of the Company's properties, which in turn could have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Changing Demand for Petroleum Products

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

Reduced Demand for Electrical or Clean Energy

Demand for electrical energy may be affected by the price and availability of other fuels, including, but not limited to, nuclear, coal and oil. The success of clean energy projects largely depends upon the increased use and widespread adoption and demand of clean energy. The timeline for when such widespread adoption will take place is uncertain. Many factors will influence the widespread adoption of renewable energy and demand for renewable energy projects, including: cost-effectiveness of clean energy technologies as compared with conventional and competitive technologies; performance and reliability of clean energy products as compared with conventional and non-renewable products; fluctuations in economic and market conditions that impact the viability of conventional and competitive alternative energy sources; increases or decreases in the prices of feedstock and energy products, such as natural gas; and availability or effectiveness of government subsidies and incentives. To the extent renewable energy becomes less cost-competitive due to reduced or eliminated government renewable energy targets and other tax credits and incentives that favour renewable energy, cheaper alternatives or otherwise, demand for renewable energy could decrease. Slow growth or a long-term reduction in renewable energy demand could have a material adverse effect on the Company's business, results of operations, financial condition and cash flows.

Third-Party Credit Risk

The Company may be exposed to third-party credit risk through its contractual arrangements with its current or future joint interest partners, crude oil and natural gas customers, counterparties related to derivative financial instruments and other parties. In the event such entities fail to meet their contractual obligations to the Company, such failures could have a material adverse effect on the Company's business, financial condition, results of operations, cash flows and future prospects.

Limited Number of Shareholders

ARC and Luminus beneficially own or control 27,504,624 Common Shares and 5,202,334 Common Shares, respectively, which in the aggregate represent approximately 63.1% and 11.9%, respectively, of the Company's issued and outstanding Common Shares. As a result, ARC will have the ability to control (or veto) certain matters submitted to the Company's shareholders for ordinary approval, including without limitation, the election and removal of directors. This may negatively affect the attractiveness of the Company to third parties considering an acquisition of the Company or cause the market price of the Common Shares to decline. In addition, ARC will be entitled to nominate up to three directors for election pursuant to the Investment Rights Agreement (ARC) and Luminus will be entitled to nominate up to one director for election pursuant to the Investment Rights Agreement (Luminus) depending on the aggregate percentage of Common Shares held from time to time by each of them. The interests of ARC may not in all cases be aligned with interests of the Shareholders. In addition, ARC may have an interest in pursuing acquisitions, divestitures and other transactions that in the judgement of its management could enhance its equity investment, even though such transactions might involve risks to the Shareholders and may ultimately affect the market price of the Common Shares. So long as ARC or its affiliates continue to own, directly or indirectly, a significant amount of the Common Shares and/or otherwise control a majority of the Board, ARC will continue to be able to strongly influence or effectively control the Company's decisions. See "*Principal Holders of Voting Securities*". Each of ARC and Luminus are in the business of making investments in companies and have made investments in or may in the future make investments in businesses that directly or indirectly compete with certain portions of the Company's business or are suppliers or clients of the Company.

Conflicts of Interest

Some of the Company's directors and officers, and ARC and Luminus, are engaged and will continue to be engaged in the oil and gas business on their own behalf and on behalf of others, and situations may arise where such directors, officers or shareholders are in direct or indirect competition with the Company. For example, these directors, officers or shareholders could pursue acquisition opportunities that may be complementary to Kiwetinohk's business and, as a result, those acquisition opportunities may not be available to the Company. Conflicts of interest, if any, which arise will be subject to and be governed by procedures prescribed by the CBCA which require a director or officer of a corporation who is party to a material contract or proposed material contract with the Company to disclose such director's or officer's interest and, with respect to a director, to refrain from voting on any matter in respect of such contract unless otherwise permitted under the CBCA.

Litigation

In the normal course of the Company's operations, it 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, related to personal injuries, property damage, property tax, land rights, the environment and contract disputes. The outcome of outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to the Company and as a result, could have a material adverse effect on its assets, liabilities, business, financial condition and results of operations.

Insufficiency of Internal Controls

Effective internal controls are necessary for the Company to provide reliable financial reports and to help prevent fraud. Although the Company will undertake a number of procedures in order to help ensure the reliability of its financial reports, including those that may be imposed on it under Applicable Securities Laws, the Company cannot be certain that such measures will ensure that the Company will maintain adequate control over financial processes and reporting. Failure to implement required new or improved controls, or difficulties encountered in their implementation, could harm the Company's results of operations or cause it to fail to meet its reporting obligations. Additionally, implementing and monitoring effective internal controls can be costly. If the Company or its independent auditors discover a material weakness, the disclosure of that fact, even if quickly remedied, could reduce the market's confidence in the Company's financial statements.

Cyber Security Risks

The Company will be subject to a variety of information technology and system risks, including potential breakdown, destruction or interruption of the Company's information technology systems caused by third parties or insiders, as well as cyber-attacks, cyber-fraud, viruses or malware infections in emails, websites, or removable media, ransomware, and social engineering activities like phishing and employee impersonation. The Company will be dependent on its information systems and computer-based programs, including its well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in the Company's hardware or software network infrastructure, possible consequences include a loss of communication links, inability to find, produce, process and sell electricity, oil, NGL and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on the Company's business.

Although the Company will have security measures and controls in place that are designed to mitigate these risks, a breach of these security measures or controls could occur as a result of the increased sophistication and volume of attacks and could result in losses of material or confidential information, reputational consequences, financial damages, breaches of privacy laws, higher insurance premiums, plant and utility outages, damage to assets, safety issues, operational downtime or delays and/or production and revenue losses. The significance of any such event is difficult to quantify, but may in certain circumstances be material to the Company and could have adverse effects on the Company's business, financial condition and results of operations.

Inability to Dispose of Non-Strategic Assets

The Company's ability to dispose of non-strategic assets, such as acreage that it does not intend to place on its drilling schedule prior to lease expirations, could be affected by various factors, including the availability of purchasers willing to purchase the non-strategic assets at prices acceptable to the Company. Sellers typically retain certain liabilities or agree to indemnify buyers for certain matters. The magnitude of such retained liability or indemnification obligation may be difficult to quantify at the time of the transaction and ultimately may be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release the Company from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a sale, the Company may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

Security Deposits Under Provincial Liability Management Programs

Alberta

As discussed in further detail below, the Government of Alberta is currently in the process of amending the liability management framework in Alberta, which leaves oil and gas companies, including the Company, in a "regulatory grey zone" as to how the regulations will be implemented and managed by the AER going forward. While the Company believes that prudent management of asset retirement obligations, including filing a closure plan and commitment with provincial regulators, will alleviate some or most of this risk, it cannot be certain how the new framework will affect the Company going forward, including in respect of licence transfers and the requirement to provide security deposits.

The Government of Alberta has developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. The program generally involves an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Although the Company does not have to post security under the existing programs, changes to the ratio of the Company's deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in the requirement for security to be posted in the future.

On June 20, 2016, the AER issued Bulletin 2016-16: Licensee Eligibility - Alberta Energy Regulator Measures to Limit Environmental Impacts Pending Regulatory Changes to Address the Redwater Decision. This Bulletin established an interim rule pursuant to which approval to transfer existing AER licences, approvals and permits would not be granted unless the transferee demonstrated that it would have an LMR of 2.0 or higher immediately following the transfer. On December 6, 2017, the AER released an updated Directive 067: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals ("**Directive 067**"), pursuant to which the AER may more closely scrutinize prospective licensees and deny licence eligibility if the applicant poses an unreasonable risk. An assessment of unreasonable risk is based on a number of factors including the licensee's compliance history, corporate structure, financial health and the experience of its officers and directors. The AER will also consider these factors when considering licence transfer applications and may deny an application if it finds that the proposed transfer is not in the public interest. All existing licence or approval holders are required to meet licence eligibility requirements prescribed by Directive 067 on an ongoing basis. Bulletin 2016-16 and Directive 067 may impact acquisitions and dispositions by oil and gas companies, including the Company.

In July 2020, after consultation with the AER, industry, and other stakeholders, the Government of Alberta announced a new liability management framework consisting of policy components, some of which remain under development. On April 7, 2021, the AER released a new edition of Directive 067, to require the provision of extensive corporate financial disclosures, insurance coverage, governance and shareholder information, including whether any director and officer was a director or officer of an energy company that has previously left wells to be reclaimed by the Orphan Well Association. Further, the new edition of Directive 067 has broadened the AER's discretion to withhold or revoke licensees' privileges if they are viewed as posing an unreasonable risk. On June 8, 2021, the AER announced that licensees with inactive infrastructure will be required to satisfy an individual annual mandatory target determined by the AER through undertaking closure work or posting a security deposit. The annual spend targets will come into effect on January 1, 2022. Also on June 8, 2021, the AER released a draft Licensee Life-Cycle Management Directive ("**LLCM Directive**") for public comment. Among other things, the draft LLCM Directive states that all AER licence transfer applications will trigger a holistic assessment of the transferor and transferee, and that posting of security (in an amount up to the licensee's total liabilities) may be required in connection with the transfer. Given the recent release of these liability management framework policy components and the ongoing development of the LLCM Directive, there is uncertainty about how the new regime will be implemented and managed by the AER and how it could impact the Company and its operations.

British Columbia

The BCOGC oversees a liability management rating program similar to the AB LMR Program in Alberta, which is designed to manage public liability exposure related to crude oil and natural gas activities by ensuring that permit holders carry the financial risks and regulatory responsibility of their operations through to regulatory closure. Under its program, the BCOGC determines the required security deposits for permit holders under the OGAA. The liability management rating is the ratio of a permit holder's deemed assets to deemed liabilities. Permit holders whose deemed liabilities exceed their deemed assets (i.e., a rating below 1.0) will be considered at-risk and reviewed for a security deposit. Permit holders that fail to comply with security deposit requirements are deemed non-compliant under the OGAA and enter the compliance and enforcement framework.

In 2019, the OSRF replaced the orphan site reclamation fund tax paid by permit holders. The OSRF is an industry-funded program created to address the abandonment and reclamation costs for orphan sites. Permit holders are required to pay their proportionate share of the levy. The OGAA permits the BCOGC to impose more than one levy in a given calendar year.

The Dormancy Regulation establishes legally imposed timelines for the restoration of crude oil and natural gas wells in British Columbia. The Dormancy Regulation classifies different sites based on activity levels associated with the well(s) on each site, with a goal of ensuring that 100% of currently dormant sites are reclaimed by 2036. There are additional regulated timelines for sites that become dormant before 2023 or become dormant after 2024. A permit holder will have varying reporting, decommissioning, remediation, and reclamation obligations that depend on the classification of its sites. Any permit holder that has a dormant site in its portfolio must develop and submit an annual work plan to the BCOGC, outlining its decommissioning and restoration activities for each calendar year. The permit holder must also prepare and submit a retrospective annual report within 60 days of the end of the calendar year in which it conducted the work outlined in the corresponding annual work plan.

Breach of Third-Party Confidentiality Obligations

While discussing potential business relationships or other transactions with third parties, the Company may disclose confidential information relating to its business, operations or affairs. Although confidentiality agreements are signed by third parties prior to the disclosure of any confidential information, a breach could put the Company at competitive risk and may have a material adverse effect on its business. The harm to the Company's 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, the Company will be able to obtain equitable remedies, such as injunctive relief, from a court of competent jurisdiction in a timely manner, if at all, in order to prevent or mitigate any damage to its business that such a breach of confidentiality may cause.

Future Expansions May Change Risk Exposure

The majority of the Company's current operations are focused on crude oil and natural gas production, exploration and development in the Montney, Duvernay and Clearwater plays. The Company expects that its future operations will consist, at least to an equal degree with oil and gas operations, in the generation of power from low carbon sources. This may result in unexpected risks or alternatively, significantly increase its exposure to one or more existing risk factors, which may in turn result in the future operational and financial conditions of the Company being adversely affected.

Competitive Pressures to Adopt New Technologies

The crude oil and natural gas and renewables industries are characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. Other crude oil and natural gas or renewables companies may have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before the Company. There can be no assurance that the Company will be able to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. One or more of the technologies currently utilized by the Company or implemented in the future may become obsolete. In such case, or if the Company is unable to utilize the most advanced commercially available technology, its business, financial condition and results of operations could be materially adversely affected. The Company may also fail to capture data required to optimize operations.

Environmental, Health and Safety Requirements

Kiwetinohk may incur significant delays, costs and liabilities as a result of federal, provincial and local environmental, health and safety requirements applicable to Kiwetinohk's exploration, development and production activities. These laws and regulations may require Kiwetinohk to obtain a variety of permits or other authorizations governing its air emissions, water discharges, earth movement, waste disposal or other environmental impacts associated with drilling, producing and other operations; regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, grasslands and other protected areas; require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or impose substantial liabilities for spills, pollution or failure to comply with regulatory obligations. In addition, these laws and regulations may restrict the rate of oil, NGL or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. Failure to comply with laws and regulations may result in the assessment of administrative, regulatory, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, the suspension or revocation of necessary permits, licences and authorizations, the requirement that additional pollution controls be installed and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Under certain environmental laws that impose strict as well as joint and several liability, Kiwetinohk may be required to remediate contaminated properties currently or formerly operated by Kiwetinohk or facilities of third parties that received waste generated by Kiwetinohk's operations regardless of whether such contamination resulted from the conduct of others or from consequences of Kiwetinohk's own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of Kiwetinohk's operations. In addition, the risk of accidental spills or releases from Kiwetinohk's operations could expose it to significant liabilities under environmental laws. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry is likely to continue and may accelerate as a result of concerns related to the impact of climate change, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, Kiwetinohk's business, prospects, financial condition or results of operations could be materially adversely affected. Although Kiwetinohk believes that it is in material compliance with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development, or exploration activities, or otherwise have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

Kiwetinohk has not established a separate reserve fund for the purpose of funding its estimated future environmental, including reclamation and abandonment, obligations. As a result, Kiwetinohk may not be able to satisfy these obligations. Any site reclamation or abandonment costs incurred in the ordinary course in a specific period will be funded out of Kiwetinohk's cash flow from operations. If Kiwetinohk is unable to fully fund the cost of remedying an environmental obligation, it might be required to suspend operations or enter into interim compliance measures pending completion of the required remedy, which could have an adverse effect on Kiwetinohk's financial condition and results of operations.

Oil, NGL and natural gas companies operating in Alberta are subject to significant regulation with respect to their employees' health and safety. Companies are required to self-report accidents and infractions, and regular and random audits of operations are also part of the regulatory process. Previous violations of the same requirement are taken into account when assessing penalties and subsequent behavior may be subjected to escalating levels of oversight and loss of operating licence. Non-compliance with regulations may in the future result in suspension or closure of Kiwetinohk's operations or the imposition of other penalties against Kiwetinohk.

In addition, the construction and future operation of the Company's proposed power generating projects carry an inherent risk of liability related to worker health and safety and the environment, including the risk of government-imposed orders to remedy unsafe conditions and/or to remediate or otherwise address environmental contamination, potential penalties for contravention of health, safety and environmental laws, licences, permits and other approvals, and potential civil liability. The Company expects to incur significant capital and operating expenditures to comply with health, safety and environmental laws and to obtain and comply with licences, permits and other approvals and to assess and manage its potential liability exposure.

Ability to Secure Appropriate Land

There is significant competition for appropriate sites for new power generating facilities. Optimal sites are difficult to identify and obtain given that geographic features, legal restrictions and ownership rights naturally limit the areas available for site development. There can be no assurance that the Company will be successful in obtaining any particular site in the future.

Risks Related to the Common Shares

The TSX Has Not Yet Approved the Listing of the Common Shares

The TSX has conditionally approved the listing of the Common Shares. Listing is subject to Company fulfilling all of the requirements of the TSX on or before February 22, 2022. There is currently no market through which the Common Shares or any other securities of the Company may be sold. If a market for the Common Shares does not develop or is not sustained, it may affect Shareholders' ability to resell their Common Shares. This may affect the pricing of the Common Shares in the secondary market, the transparency and availability of trading prices, the liquidity of the Common Shares and the extent of issuer regulation.

The price of the Common Shares could be volatile.

A number of factors could influence the volatility in the trading price of the Common Shares, including changes in the economy or in the financial markets, industry related developments and the impact of changes in the Company's daily operations. Each of these factors could lead to increased volatility in the market price of the Common Shares. In addition, variations in the Company's earnings estimates or other financial or operating metrics by securities analysts and the market prices of the securities of the Company's competitors may also lead to fluctuations in the trading price of the Common Shares.

There may be no return on investment in the Common Shares.

There is no assurance that the business of the Company will be operated successfully, or that the business will generate sufficient income to allow investors to recoup all or any portion of their investment. There is no assurance that an investment in the Common Shares will earn a specified rate of return or any return over the life of the investment.

The Company has no plans to pay dividends.

The Company currently intends to use its future earnings, if any, and other cash resources for the operation and development of its business and does not currently anticipate paying any dividends on the Common Shares. Any future determinations to pay dividends on the Common Shares will be at the sole discretion of the Board of Directors after considering a variety of factors and conditions existing from time to time, including current and future commodity prices, production levels, capital investment requirements, debt service requirements, operating costs, royalty burdens, foreign exchange rates and the satisfaction of the liquidity and solvency tests imposed by the CBCA for the declaration and payment of dividends. As a result, a holder of Common Shares may not receive any return on an investment in the Common Shares.

The Common Shares will be subject to further dilution.

The Company may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Company which may be dilutive. No prediction can be made as to the effect, if any, such future sales of Common Shares will have on the market price of the Common Shares prevailing from time to time. The sale of a substantial number of the Common Shares in the public market, or the perception that such sales may occur, could adversely affect the prevailing market price of the Common Shares and negatively impact the Company's ability to raise equity capital in the future.

The forward-looking statements contained in this AIF may prove to be inaccurate.

This AIF contains forward-looking statements, which by its nature involves numerous assumptions, known and unknown risk and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking statements or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate. The factors discussed in this section and the section entitled "*Forward-Looking Statements and Market Data*" should therefore be weighed carefully and prospective investors should not place undue reliance on the forward-looking statements provided in this AIF. Additional information on the risks, assumptions and uncertainties are found in this AIF under the heading "*Forward-Looking Statements and Market Data*".

PRESENTATION OF OIL AND GAS RESERVES AND PRODUCTION INFORMATION

The reserves information contained in this AIF has been prepared in accordance with NI 51-101 and COGEH. Listed below are cautionary statement(s) that are specifically required by NI 51-101 that qualify the oil and gas disclosure contained in this AIF and the appendices hereto.

The terms "boe" and "mcfe" may be misleading, particularly if used in isolation. A boe conversion rate of six thousand cubic feet of natural gas per barrel of oil (6 mcf:1 bbl) and an mcfe conversion rate of one barrel of oil per six thousand cubic feet of natural gas (1 bbl:6 mcf) are each based on an energy equivalency conversion method primarily applicable at the burner tip and do not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from an energy equivalency of 6:1, utilizing a conversion ratio of 6:1 may be misleading as an indication of value.

The discounted and undiscounted net present value of future net revenues attributable to the Company's reserves do not represent the fair market value of the Company's reserves. There is no assurance that the forecast prices and costs assumptions applied by Kiwetinohk's independent reserves evaluator in evaluating the reserves of the Company will be attained and variances could be material. The estimates of Kiwetinohk's light and medium crude oil, NGL, conventional natural gas and shale gas reserves provided in this AIF or otherwise referred to in this AIF are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual light and medium crude oil, NGLs, conventional natural gas and shale gas reserves may be greater than or less than the estimates provided in this AIF or otherwise referred to in this AIF, and the difference may be material.

The determination of light and medium crude oil, NGL, conventional natural gas and shale gas reserves involves the preparation of estimates that have an inherent degree of associated risk and uncertainty. The estimation and classification of reserves is a complex process involving the application of professional judgment combined with geological and engineering knowledge to assess whether specific classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions. In addition, rules set forth in the COGE Handbook and NI 51-101 override professional judgments as to volumes of recovery, well productivity and other factors.

NI 51-101 defines "shale gas" as natural gas: (a) contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily absorbed on the kerogen or clay minerals; and (b) that usually requires the use of hydraulic fracturing to achieve economic production rates. Kiwetinohk has also categorized what is typically referred to as "tight gas" under "shale gas" since "tight gas" is not defined in NI 51-101. This includes natural gas that is contained in low-permeability shales, siltstones and carbonates, in which the natural gas is primarily contained in microscopic pore spaces that are poorly connected to one another, which typically requires the use of hydraulic fracturing to achieve economic production rates.

References herein to 90 day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for the Company or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Company cautions that the test results should be considered preliminary.

The information set forth in this AIF relating to Kiwetinohk's reserves and future net revenues constitutes forward-looking statements which are subject to certain risks and uncertainties. See "*Forward-Looking Statements and Market Data*" and "*Risk Factors*".

Unless otherwise specified, the NGLs reported by McDaniel, the Company's independent qualified reserves evaluator, that are referred to in this AIF are reported on a combined basis with any condensate as required under NI 51-101.

Reserves Disclosure

Reserves are classified as proved reserves or probable reserves according to the certainty associated with the estimates. Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories. For definitions of each of these reserve categories and certain related terminology that is used in this AIF, see "*Glossary, Selected Abbreviations and Selected Conversions — Glossary*" in Appendix "A". Additional clarification of the classification of reserves, the certainty levels associated with reserves estimates and the effect of aggregation are provided in the COGE Handbook.

The qualitative certainty levels referred to in the definitions of proved reserves, probable reserves, developed reserves, developed non-producing reserves, developed producing reserves and undeveloped reserves (as such terms are defined under "*Glossary, Selected Abbreviations and Selected Conversions — Glossary*" in Appendix "A") are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- at least a 90% probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

- at least a 50% 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 are 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.

STATEMENT OF RESERVES DATA

Statement of Reserves Data and Other Oil and Natural Gas Information

Set forth below is a summary of the light and medium crude oil, heavy crude oil, tight oil, conventional natural gas, shale gas and NGL reserves of the Company, Distinction and the Simonette Assets as collectively evaluated in the 2021 Pro Forma Reserves Report and the 2020 Reserves Report. Summaries of the 2020 Reserves Reports evaluating the reserves of each of Kiwetinohk, Distinction and the Simonette Assets, respectively, as at December 31, 2020, are included in Appendix "F" to this AIF.

Each of the 2021 Pro Forma Reserves Report and the 2020 Reserves Reports have been prepared in accordance with the standards contained in COGEH and the reserves definitions contained in NI 51-101 and CSA 51-324. Kiwetinohk engaged McDaniel to prepare the 2021 Pro Forma Reserves Report, the 2020 Kiwetinohk Reserves Report and the 2020 Simonette Assets Reserves Report and Distinction engaged GLJ to prepare the 2020 Distinction Reserves Report.

Disclosure of Reserves Data

The reserves data set forth in this AIF is based upon the 2021 Pro Forma Reserves Report and the 2020 Reserves Reports each prepared in accordance with the standards contained in COGEH and the reserves definitions contained in NI 51-101 and CSA 51-324. The 2020 Kiwetinohk Reserves Report, the 2020 Distinction Reserves Report and the 2020 Simonette Assets Reserves Report, from which the data set forth in Appendix "F" is derived, are dated January 21, 2021, March 5, 2021 and January 21, 2021, respectively, and evaluate the applicable reserves as at December 31, 2020. The 2021 Pro Forma Reserves Report, from which the data below is derived, is dated July 16, 2021 and evaluated the reserves attributable to Kiwetinohk following completion of the Business Combination assuming an effective date of July 1, 2021. The 2021 Pro Forma Reserves Report also reflects adjustments in Kiwetinohk's reserves subsequent to year end 2020 to account for the Company's prioritization of developing the Simonette Assets and corresponding schedule of development changes for other assets.

The reserves data summarizes the conventional natural gas, shale gas, NGL, tight oil and heavy crude oil reserves of the Company, Distinction and the Simonette Assets, as applicable, and the net present values of future net revenue for the reserves using forecast prices and costs, not including the impact of any price risk management activities. All of the reserves of Kiwetinohk, Distinction and the Simonette Assets are in the provinces of Alberta and British Columbia.

The present value of future net revenue before and after income taxes has been estimated by McDaniel or GLJ, as applicable. The estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and includes assumptions and estimates of tax pools provided by management of the applicable entity 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 the applicable entity's crude oil and natural gas properties reflects the tax burden of its properties on a stand-alone basis. It does not provide an estimate of the value of the applicable entity as a business entity, which may be significantly different.

All evaluations of future net revenue contained in the 2021 Pro Forma Reserves Report and the 2020 Reserves Reports are after the deduction of royalties, development costs, production costs and abandonment and reclamation costs but before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by McDaniel or GLJ, as applicable, represent the fair market value of those reserves. There is no assurance that the forecast price and cost assumptions contained in the 2021 Pro Forma Reserves Report, the 2020 Kiwetinohk Reserves Report, the 2020 Distinction Reserves Report or the 2020 Simonette Assets Reserves Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized herein. Readers should review the relevant definitions and information that is contained in "*Glossary, Selected Abbreviations and Selected Conversions*" in Appendix "A". The recovery and reserves estimates described herein are estimates only. See "*Risk Factors*".

The historical production information used by McDaniel or GLJ, as applicable came from government sources. In instances where recent production numbers were not publicly available, they were provided by the applicable entity. The applicable entity also provided McDaniel or GLJ, as applicable, with other required information, such as operating statements, land data, logs from recently drilled wells and field development plans. McDaniel or GLJ, as applicable, incorporated all this data into its analysis in accordance with standards set out in the COGEH. The standards in the COGEH require McDaniel and GLJ to plan and perform an assessment of the applicable reserves data in order to obtain reasonable assurance as to whether such reserves data are free of material misstatement.

2021 Pro Forma Reserves Report

The tables below summarize the data contained in the 2021 Pro Forma Reserves Report and, as a result, may contain slightly different numbers than such report due to rounding. Due to rounding, certain columns may not add exactly. Except as otherwise indicated, net present values and future net revenues are based on McDaniel's forecast prices, as set forth below.

Summary of Reserves (Forecast Prices and Costs)

Summary of Reserves
As of July 1, 2021 — Forecast Prices and Costs

	Light and Medium Crude Oil		Heavy Crude Oil		Tight Oil	
Reserves Category	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
Proved:						
Developed Producing	--	--	94.8	85.4	427.4	370.3
Developed Non-Producing	--	--	--	--	--	--
Undeveloped	--	--	135.6	120.7	--	-
Total Proved(1)	--	--	230.5	206.1	427.4	370.3
Total Probable	--	--	650.8	567.6	138.6	113.0
Total Proved plus Probable(4)	--	--	881.2	773.7	565.9	483.2

	Conventional Natural Gas		Shale Gas		NGL(3)	
Reserves Category	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
	(mmcf)	*(mmcf)*	*(mmcf)*	*(mmcf)*	*(mbbl)*	*(mbbl)*
Proved:						
Developed Producing	4,422.1	3,852.3	111,286.6	103,699.0	16,636.3	13,694.6
Developed Non-Producing	179.8	153.9	4,771.7	4,533.0	741.6	584.8
Undeveloped	--	--	226,624.3	213,859.4	39,661.8	34,818.4
Total Proved(1)	4,601.9	4,006.2	342,682.6	322,091.4	57,039.7	49,097.8
Total Probable	1,412.9	1,262.6	229,415.9	213,712.9	32,211.5	25,750.4
Total Proved plus Probable(4)	6,014.8	5,268.8	572,098.5	535,804.3	89,251.3	74,848.3

	Total	
Reserves Category	**Gross(1)**	**Net(2)**
	(mboe)	*(mboe)*
Proved:		
Developed Producing	36,443.3	32,075.5
Developed Non-Producing	1,566.9	1,366.0
Undeveloped	77,568.1	70,582.3

Total Proved[1]	115,578.3	104,023.8
Total Probable	71,472.3	62,260.2
Total Proved plus Probable[4]	187,050.6	166,283.9

Notes:

(1) Gross reserves are working interest reserves before royalty deductions.

(2) Net reserves are working interest reserves after royalty deductions plus royalty interest reserves.

(3) Figures include NGL for both conventional and unconventional reservoirs, including condensate, pentane plus, propane, butane and ethane. Condensate is expected to be extracted in the field and sold separately from other NGL or sold with other NGL delivered to fractionation facilities. Other NGL (propane, butane and ethane) are expected to be extracted in the field by Kiwetinohk. Condensate represents 72% and pentanes plus represents 6% on a volume basis for Total Proved, and 70% condensate and 7% pentanes plus on a volume basis for Total Proved Plus Probable.

(4) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "*Glossary, Selected Abbreviations and Selected Conversions*" in Appendix "A".

Net Present Values of Future Net Revenue
Before Income Taxes Discounted At (%/Year)
As of July 1, 2021
Forecast Prices and Costs[1]

Reserves Category	0%	5%	10%	15%	20%	Unit Value Discounted at 10% per Year $/boe[3]
	($mm)	*($mm)*	*($mm)*	*($mm)*	*($mm)*	
Proved:						
Developed Producing	631.4	536.5	448.0	385.3	340.6	13.97
Developed Non-Producing	27.7	21.1	17.0	14.2	12.3	12.43
Undeveloped	1,381.3	905.3	626.4	449.2	329.4	8.87
Total Proved[2]	2,040.4	1,462.8	1,091.3	848.7	682.2	10.49
Total Probable	1,489.1	797.7	487.8	326.4	232.5	7.84
Total Proved plus Probable[2]	3,529.5	2,260.5	1,579.2	1,175.1	914.7	9.50

Notes:

(1) Estimates of future net revenue do not represent fair market value.

(2) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "*Glossary, Selected Abbreviations and Selected Conversions*" in Appendix "A".

(3) The unit values are based on net reserve volumes.

Net Present Values of Future Net Revenue
After Income Taxes Discounted At (%/Year)
As of July 1, 2021 — Forecast Prices and Costs[1]

Reserves Category	0%	5%	10%	15%	20%
	($mm)	*($mm)*	*($mm)*	*($mm)*	*($mm)*
Proved:					
Developed Producing	629.1	535.5	447.5	385.1	340.5
Developed Non-Producing	21.2	18.1	15.5	13.5	11.9
Undeveloped	1,064.0	689.9	470.3	330.8	236.7
Total Proved[2]	1,714.2	1,243.4	933.3	729.4	589.1
Total Probable	1,149.9	609.8	369.1	244.7	173.1
Total Proved plus Probable[2]	2,864.1	1,853.3	1,302.4	974.1	762.2

Notes:

(1) Estimates of future net revenue do not represent fair market value.

(2) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "*Glossary, Selected Abbreviations and Selected Conversions*" in Appendix "A".

Total Future Net Revenue (Undiscounted)
As of July 1, 2021 Forecast Prices and Costs

Reserves Category	Revenue[1]	Royalties[2]	Operating Costs	Development Costs	Abandonment and Reclamation Costs[3]	Future Net Revenue Before Income Taxes[4]	Income Taxes	Future Net Revenue After Income Taxes[4]
	($mm)	*($mm)*	*($mm)*	*($mm)*	*($mm)*	*($mm)*	*($mm)*	*($mm)*
Total Proved[5]	4,883.7	602.3	1,135.2	955.1	150.7	2,040.4	326.2	1,714.2
Total Proved plus Probable[5]	8,018.4	1,152.8	1,852.4	1,317.0	166.7	3,529.5	665.4	2,864.1

Notes:

(1) Total revenue includes revenue before royalties and includes other income.

(2) Royalties include Crown, freehold and overriding royalties, mineral tax and net profit interest payments.
(3) Abandonment and reclamation costs are defined by NI 51-101 as all costs associated with the process of restoring Kiwetinohk's properties that have been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.
(4) Estimates of future net revenue do not represent fair market value.
(5) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserve categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "*Glossary, Selected Abbreviations and Selected Conversions*" in Appendix "A".

Future Net Revenue by Production Group
As of July 1, 2021 Forecast Prices and Costs

Reserves Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%/year)[(1)(2)]	Unit Value[(2)(3)]
		($mm)	***($/mcf) ($/bbl)***
Total Proved[(4)]	Heavy Crude Oil (Including Solution Gas and By-products)	4.2	20.3
	Tight Oil (Including Solution Gas and By-products)	13.0	35.2
	Conventional Natural Gas (Including By-products)	2.4	0.6
	Shale Gas (Including By-products)	1,071.7	3.3
	Total	**1,091.3**	
Proved plus Probable	Heavy Crude Oil (Including Solution Gas and By-products)	13.7	17.7
	Tight Oil (Including Solution Gas and By-products)	15.3	31.6
	Conventional Natural Gas (Including By-products)	3.4	0.7
	Shale Gas (Including By-products)	1,546.8	2.9
	Total	**1,579.2**	

Notes:
(1) The before tax future net revenue discounted at 10% for shale gas includes all by-product revenue streams from ethane, propane, butane and pentanes plus.
(2) Estimates of future net revenue do not represent fair market value. May not sum due to rounding.
(3) Unit values are based on Kiwetinohk's net reserves. Values shown for light and medium crude oil are expressed as $/bbl and values shown for conventional natural gas and shale gas are expressed as $/mcf.
(4) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "*Glossary, Selected Abbreviations and Selected Conversions*" in Appendix "A".

Pricing Assumptions

The forecast of prices, inflation and exchange rates provided in the table below were computed by McDaniel, effective July 1, 2021. McDaniel's forecasts were utilized in the 2021 Pro Forma Reserves Report and the summary of McDaniel's evaluation that is reflected herein.

Summary of Pricing and Inflation Rate Assumptions
As of July 1, 2021 Forecast Prices and Costs

	Crude Oil				Natural Gas		NGL					
Year	**WTI Cushing Oklahoma**	**Edmonton Par Price 40° API**	**Hardisty Heavy 12° API**	**Cromer Medium 29° API**	**AECO Gas Price**	**U.S. Henry Hub Gas Price US$**	**Edmonton Ethane**	**Edmonton Propane**	**Edmonton Butane**	**Edmonton Pentane**	**INFLATION RATE[(1)]**	**EXCHANGE RATE[(2)]**
	(US$/bbl)	**($/bbl)**	**($/bbl)**	**($/bbl)**	**($/mmBtu)**	**(US$/mmBtu)**	**($/bbl)**	**($/bbl)**	**($/bbl)**	**($/bbl)**	**%/Year**	**(US$/$)**
2021 *(six months)*	72.00	83.75	72.86	81.24	3.40	3.40	12.80	35.59	37.69	87.75	0.0	0.80
2022	66.30	76.94	64.63	73.09	3.06	3.16	11.42	32.70	38.47	81.02	2.0	0.80
2023	62.42	71.97	58.30	68.38	2.65	2.86	9.78	30.59	41.38	76.14	2.0	0.80
2024	61.02	70.10	56.78	66.59	2.71	2.92	9.98	29.79	40.31	74.34	2.0	0.80
2025	62.24	71.50	57.91	67.92	2.76	2.98	10.17	30.39	41.11	75.83	2.0	0.80
2026	63.48	72.93	59.07	69.28	2.82	3.04	10.38	30.99	41.93	77.35	2.0	0.80
Thereafter			Escalated at 2.0%								2.0	0.80

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized (before hedging and marketing income) by the Company for the period from July 1, 2020 to June 30, 2021, were $76.35 bbl for condensate, $38.67/bbl for other NGL (excluding condensate and pentane extracted from the gas stream), $3.94/mcf for natural gas, $57.80/bbl for light and medium oil and $43.81/bbl for heavy crude oil.

Reserves Reconciliation

Reconciliation of Gross Reserves by Product Type
Forecast Prices and Costs

	Conventional Natural Gas			Shale Gas		
	Total Proved	Total Probable	Total Proved plus Probable	Total Proved	Total Probable	Total Proved plus Probable
	(mmcf)	*(mmcf)*	*(mmcf)*	*(mmcf)*	*(mmcf)*	*(mmcf)*
January 1, 2021(3)	16,097.3	20,315.6	36,412.9	77,162.1	19,488.8	96,650.9
Discoveries	--	--	--	--	--	--
Extensions and Improved Recovery	--	--	--	--	--	--
Technical Revisions	(16,122.3)	(20,383.3)	(36,505.6)	(27,826.0)	29,339.7	1,513.7
Acquisitions	5,206.9	1,413.2	6,620.1	302,286.4	180,612.7	482,899.1
Dispositions	--	--	--	--	--	--
Economic Factors(1)	25.0	67.7	92.7	546.4	(14.5)	531.9
Production	(604.9)	(0.4)	(605.3)	(9,486.2)	(10.9)	(9,497.1)
July 1, 2021(4)	4,602.0	1,412.8	6,014.8	342,682.7	229,415.8	572,098.5

	NGL(2)			Light and Medium Crude Oil		
	Total Proved	Total Probable	Total Proved plus Probable	Total Proved	Total Probable	Total Proved plus Probable
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*
January 1, 2021(3)	8,781.4	3,175.5	11,956.9	5,980.4	7,592.7	13,573.1
Discoveries	--	--	--	--	--	--
Extensions and Improved Recovery	--	--	--	--	--	--
Technical Revisions	(3,835.4)	1,803.6	(2,031.8)	(5,991.8)	(7,615.7)	(13,607.5)
Acquisitions	53,297.4	27,231.3	80,528.7	--	--	--
Dispositions	--	--	--	--	--	--
Economic Factors(1)	56.3	2.8	59.1	11.4	23.0	34.4
Production	(1,259.9)	(1.6)	(1,261.5)	--	--	--
July 1, 2021(4)	57,039.8	32,211.6	89,251.4	--	--	--

	Tight Oil			Heavy Crude Oil		
	Total Proved	Total Probable	Total Proved plus Probable	Total Proved	Total Probable	Total Proved plus Probable
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mboe)*	*(mboe)*
January 1, 2021(3)	--	--	--	150.2	289.1	439.3
Discoveries	--	--	--	--	--	--
Extensions and Improved Recovery	--	--	--	79.0	353.9	432.9
Technical Revisions	502.1	138.6	640.7	2.3	(1.9)	0.4
Acquisitions	--	--	--	--	--	--
Dispositions	--	--	--	--	--	--
Economic Factors(1)	--	--	--	4.5	9.7	14.2
Production	(74.7)	(0.1)	(74.8)	(5.5)	(0.1)	(5.6)
July 1, 2021(4)	427.4	138.5	565.9	230.5	650.7	881.2

	Total boe		
	Total Proved	Total Probable	Total Proved plus Probable
	(mboe)	*(mboe)*	*(mboe)*
January 1, 2021(3)	30,455.2	17,691.4	48,146.6
Discoveries	--	--	--
Extensions and Improved Recovery	79.0	353.9	432.9
Technical Revisions	(16,647.5)	(4,182.7)	(20,830.2)
Acquisitions	104,546.3	57,569.0	162,115.2
Dispositions	--	--	--
Economic Factors(2)	167.4	44.4	211.8
Production	(3,022.0)	(3.7)	(3,025.6)
July 1, 2021(4)	115,578.5	71,472.2	187,050.7

Notes:

(1) Economic factors reflect the change in forecasted commodity prices year-over-year.

(2) Figures include NGL for both conventional and unconventional reservoirs, including condensate, pentanes plus, propane, butane and ethane. Condensate is expected to be extracted in the field and sold separately from other NGL or sold with other NGL delivered to fractionation facilities. Other NGL (propane, butane and ethane) are expected to be extracted in the field by Kiwetinohk. Condensate represents 72% and pentanes plus represents 6% on a volume basis for Total Proved, and 70% condensate and 7% pentanes plus on a volume basis for Total Proved Plus Probable, as at July 1, 2021.

(3) January 1, 2021 balances reflect the Company's reserves at January 1, 2021 without giving effect to the Business Combination or the Simonette Acquisition.

(4) July 1, 2021 balances reflect the acquisition of Distinction and Simonette Assets (as shown in the "Acquisitions" category) plus additional technical revisions including reclassification of reserves from light medium oil to tight oil, conventional gas to shale gas as well as revised development plans shifting capital to more economic assets.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty to be recoverable where significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. Probable undeveloped reserves are those additional reserves that are less certain to be recovered than proved reserves where significant expenditure is required to render them capable of production. The 2021 Pro Forma Reserves Report contains proved and probable undeveloped reserves that have been estimated in accordance with the procedures and standards contained in the COGEH.

As of July 1, 2021, undeveloped reserves represented approximately 67% of total proved reserves and approximately 74% of total proved plus probable reserves. The timing of proved undeveloped reserve and probable undeveloped reserve development beyond two years is due to the large land base, a well-defined drilling inventory supported by offset production, Kiwetinohk's scheduled pace of commercial development, and the timing of planned and current infrastructure construction.

The pace of development of these reserves is influenced by several factors including, but not limited to, the outcomes of drilling and reservoir evaluations, changes in commodity pricing, changes in capital allocations, changing technical conditions, access to markets, regulatory changes and impact of future acquisitions and dispositions. These reserves are reviewed and development plans are revised accordingly as new information becomes available.

The following tables set forth the Company's gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type for the period from January 1, 2021 to June 30, 2021, January 1, 2020 to December 31, 2020 and January 1, 2019 to December 31, 2019, based on forecast prices and costs.

Proved Undeveloped Reserves

	Conventional Natural Gas (mmcf)		**Shale Gas** (mmcf)	
Year	**First Attributed**	**Cumulative at Period End**	**First Attributed**	**Cumulative at Period End**
Jan 1, 2019 - Dec 31, 2019	12,593.0	12,593.0	--	--
Jan 1, 2020 - Dec 31, 2020	--	14,510.5	77,162.1	77,162.1
Jan 1, 2021 - June 30, 2021	--	--	178,385.6	226,624.3

	NGL[(1)] (mbbl)		**Light and Medium Crude Oil** (mbbl)	
Year	**First Attributed**	**Cumulative at Period End**	**First Attributed**	**Cumulative at Period End**
Jan 1, 2019 - Dec 31, 2019	703.7	703.7	5,796.3	5,796.3
Jan 1, 2020 - Dec 31, 2020	7,853.0	8,690.0	--	5,448.9
Jan 1, 2021 - June 30, 2021	34,752.4	39,661.8	--	--

	Heavy Crude Oil (mbbl)		**Tight Oil** (mbbl)	
Year	**First Attributed**	**Cumulative at Period End**	**First Attributed**	**Cumulative at Period End**
Jan 1, 2019 - Dec 31, 2019	--	--	--	--
Jan 1, 2020 - Dec 31, 2020	132.2	132.2	--	--
Jan 1, 2021 - June 30, 2021	--	135.6	--	--

Probable Undeveloped Reserves

Year	Conventional Natural Gas		Shale Gas	
	First Attributed	Cumulative at Period End	First Attributed	Cumulative at Period End
	(mmcf)		(mmcf)	
Jan 1, 2019 - Dec 31, 2019	17,034.9	17,034.9	--	--
Jan 1, 2020 - Dec 31, 2020	--	19,815.2	19,488.8	19,488.8
Jan 1, 2021 - June 30, 2021	--	--	149,437.8	197,843.9

Year	NGL[(1)]		Light and Medium Crude Oil	
	First Attributed	Cumulative at Period End	First Attributed	Cumulative at Period End
	(mbbl)		(mbbl)	
Jan 1, 2019 - Dec 31, 2019	962.4	962.4	7,837.0	7,837.0
Jan 1, 2020 - Dec 31, 2020	2,015.2	3,146.0	--	7,424.1
Jan 1, 2021 - June 30, 2021	22,405.3	27,363.5	--	--

Year	Heavy Crude Oil		Tight Oil	
	First Attributed	Cumulative at Period End	First Attributed	Cumulative at Period End
	(mbbl)		(mbbl)	
Jan 1, 2019 - Dec 31, 2019	--	--	--	--
Jan 1, 2020 - Dec 31, 2020	281.0	281.0	--	--
Jan 1, 2021 - June 30, 2021	324.6	615.6	--	--

Note:

(1) Figures include NGL for both conventional and unconventional reservoirs, including condensate, pentanes plus, propane, butane and ethane. Condensate is expected to be extracted in the field and sold separately from other NGL or sold with other NGL delivered to fractionation facilities. Other NGL (propane, butane and ethane) are expected to be extracted in the field by Kiwetinohk. Condensate and pentanes plus represent 63% and 7% of the NGL reflected in the Gross Proved and Gross Proved plus Probable categories, respectively, as at December 31, 2020.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgment and decision-making on the basis of the available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on production expectations, forecast prices and economic conditions as at July 1, 2021. Factors and assumptions that affect these reserves estimates include, among other things: (a) historical production in the area compared with production rates from analogous producing areas; (b) initial production rates; (c) production decline rates; (d) ultimate recovery of reserves; (e) success of future development activities; (f) marketability of production; (g) effects of government regulations; and (h) government levies imposed over the life of the reserves.

As circumstances change and additional data become available, reserves estimates may also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well and reservoir performance, geological conditions, production, prices, changes in corporate strategy, economic conditions and governmental restrictions. These revisions can be either positive or negative.

In connection with its operations, Kiwetinohk will incur abandonment, dismantling, reclamation and remediation costs for surface leases, wells, facilities and pipelines. Kiwetinohk budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its oil and gas assets. Kiwetinohk retains an independent third party engineering firm to validate the estimates of such liabilities. There are no unusually significant abandonment and reclamation costs associated with its reserves properties or to properties with no attributed reserves.

The evaluated crude oil and natural gas properties of Kiwetinohk have no material extraordinary risks or uncertainties beyond those that are inherent in unconventional crude oil and natural gas exploration and production operations. See "*Risk Factors*".

Future Development Costs

The following table sets forth development costs deducted in the estimation of Kiwetinohk's future net revenue attributable to the reserves categories noted below.

Year	ANNUAL DEVELOPMENT COSTS Total Proved	Total Proved plus Probable
	($mm)	***($mm)***
2021 (remaining)	37.7	39.1
2022	192.1	197.7
2023	222.6	222.6
2024	235.3	235.3
2025	239.9	239.9
Thereafter	27.6	382.4
Total (Undiscounted)[(1)]	**955.1**	**1,317.0**
Total (Discounted at 10%)	**743.5**	**951.3**

Note:

(1) Numbers may not add due to rounding.

Kiwetinohk expects to fund the development costs of its reserves through current working capital, cash flow from operations, borrowings under its credit facilities and by accessing the global capital markets. There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all of the reserves attributed in the 2021 Pro Forma Reserves Report. Failure to develop those reserves could have a negative impact on Kiwetinohk's future net revenue relative to the estimates provided herein.

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

The future development costs set forth above do not include costs associated with abandonment and reclamation obligations.

Other Oil and Natural Gas Information

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which Kiwetinohk had a working interest as at July 1, 2021, all of which are located in Alberta.

Natural Gas Wells				Oil Wells			
Producing[(1)]		Non-Producing[(1)]		Producing[(1)]		Non-Producing[(1)]	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
200.0	173.8	247.0	126.4	22.0	15.6	50.0	32.8

Note:

(1) Producing wells are wells that are actively producing as of the respective date. Non-producing wells are wells that are not actively producing, and for which a reclamation certificate has not been granted, as of the respective date.

Properties with No Attributed Reserves

The following table sets forth the Company's properties with no reserves assigned as at July 1, 2021:

Unproved (Acres)	Gross	Net
Alberta	488,745	417,091
British Columbia	28,128	12,407
Total	**516,873**	**429,498**

The Company will continually review the economic viability and ranking of these unproved properties on the basis of product pricing, capital availability, the anticipated cost to re-acquire, and the allocation and level of infrastructure development in any specific area. From this process, some properties are scheduled for economic development activities while others are temporarily held inactive, sold, swapped or allowed to expire. There is no guarantee that commercial reserves will be discovered or developed on these properties.

When determining acreage, totals are adjusted to remove overlapping acreage under applicable petroleum and natural gas agreements.

From the period commencing July 1, 2021 and ending December 31, 2021, approximately 42,500 net acres of the Company will come up for expiry. Kiwetinohk believes that, subject to Crown approval approximately 10% of these lands will be continued and the remainder will be terminated and no longer held by the Company.

None of these properties are subject to any work commitments.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

There are several economic factors and significant uncertainties that will affect Kiwetinohk's anticipated development of its properties to which no reserves are attributed. Kiwetinohk will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil, natural gas and NGL from these properties in the future. If cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to Kiwetinohk. Failure to obtain such financing on a timely basis could cause Kiwetinohk to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations on such properties. The inability of Kiwetinohk to access sufficient capital for its exploration and development purposes could have a material adverse effect on Kiwetinohk's ability to execute its business strategy to develop these prospects. See "*Risk Factors".* The primary economic factors that affect the development of the properties to which no reserves have been attributed are future commodity prices for oil, natural gas and NGL (and Kiwetinohk's outlook relating to such prices) and the future costs of drilling, completing, tying-in and operating wells at the time that such activities are considered. Kiwetinohk would also need to secure adequate transportation capacity on acceptable terms for its incremental future production. The primary uncertainties that affect the development of such lands are the future drilling and completion results achieved in the development activities, drilling and completion results achieved by others on lands in close proximity to these lands, and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Conversely, uncertainty as to the timing and nature of the evolution or development of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such properties.

McDaniel has estimated undiscounted and inflated abandonment and reclamation costs of approximately $166.7 million in respect of its evaluation of the Company's proved plus probable reserves. Kiwetinohk does not expect that these abandonment or reclamation costs will materially affect the anticipated development production activities on its properties with no attributes reserves.

Production Estimates

The following table sets out for each product type the gross volume of production estimated for the six-month period ending December 31, 2021 in the estimates contained in the 2021 Pro Forma Reserves Report for gross proved reserves and gross probable reserves. Actual results may differ significantly from the information below. See "*Forward-Looking Statements and Market Data*" and "*Risk Factors*".

Production Estimate for the
Six-Month Period Ending December 31, 2021

	Conventional Natural Gas	Shale Gas	NGL	Light and Medium Crude Oil	Heavy Crude Oil	Tight Oil	Total
	(mmcf)	*(mmcf)*	*(mmbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mboe)*
Reserve Category							
Proved	588	9,039	1197.5	0	32.1	56	2,890.1
Probable	6	208	33.3	0	9.6	1.3	79.9
Total Proved plus Probable	594	9,247	1230.8	0	41.7	57.3	2970.0

Production History

The following tables summarize certain information in respect of the production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below.

	Quarter Ended			
	September 30, 2020	**December 31, 2020**	**March 31, 2021**	**June 30, 2021**
Average Gross Daily Production(1)(6)				
Conventional Natural Gas (mmcf/d)(8)	--	--	--	2.2
Shale Gas (mmcf/d)	1.6	1.0	1.2	34.5
Natural Gas Liquids (bbl/d)				
Condensate(2)	18	13	77	3,096
Other NGL	64	41	92	1,220
Total NGL	82	54	169	4,316
Tight Oil (bbl/d)(3)(8)	435	373	344	331
Heavy Crude Oil(3) (bbl/d)	15	43	33	29
Combined (boe/d)	793	645	741	10,797
Average Production Prices Received				
Conventional Natural Gas ($/mcf)(8)	--	--	--	3.36
Shale Gas ($/mcf)(8)	2.38	2.66	3.19	4.14
Natural Gas Liquids ($/bbl)				
Condensate(2)	43.02	55.56	77.96	76.60
Other NGL	11.15	14.04	24.41	42.04
Total NGL(8)	18.21	23.87	48.88	66.83
Tight Oil (bbl/d)(3)(8)	46.59	48.57	65.23	75.61
Heavy Crude Oil($/bbl)	31.06	35.58	48.28	57.85
Combined ($/boe)	32.74	36.83	48.62	43.01
Royalties Paid				
Conventional Natural Gas ($/mcf)(8)	--	--	--	1.41
Shale Gas ($/mcf)	(0.10)	(2.08)	0.13	0.05
Natural Gas Liquids ($/bbl)				
Condensate(5)	(5.47)	407.48	(4.26)	(6.49)
Other NGL	(1.92)	5.52	(2.43)	(7.70)
Total NGL(5)	(2.70)	100.72	(3.26)	(6.83)
Tight Oil (bbl/d)(3)(8)	(5.37)	(5.52)	(5.23)	(9.90)
Heavy Crude Oil($/bbl)	(3.12)	(4.75)	(4.94)	(7.02)
Combined ($/boe)	(3.49)	1.57	(3.19)	(2.60)
Production Costs(3)				
Conventional Natural Gas ($/mcf)(8)	--	--	--	(0.76)
Shale Gas ($/mcf)	(0.66)	(0.72)	(0.57)	(0.78)
Natural Gas Liquids ($/bbl)				
Condensate(2)	(11.91)	(15.00)	(13.99)	(14.65)
Other NGL	(3.09)	(3.79)	(4.38)	(8.11)
Total NGL	(5.04)	(6.44)	(8.77)	(12.80)
Tight Oil (bbl/d)(3)(8)	(12.90)	(13.11)	(11.70)	(10.05)
Heavy Crude Oil ($/bbl)	(8.60)	(9.60)	(8.66)	(7.38)
Combined ($/boe)	(9.07)	(9.94)	(8.72)	(8.10)
Transportation Costs				
Conventional Natural Gas ($/mcf)	--	--	--	(0.23)
Shale Gas ($/mcf)	--	--	--	(1.01)
Natural Gas Liquids ($/bbl)(9)	--	--	--	
Condensate(2)	--	--	--	(3.09)
Other NGL	--	--	--	(1.16)
Total NGL	--	--	--	(2.54)
Tight Oil (bbl/d)(3)(8)	(1.22)	(1.68)	(1.60)	(4.08)
Heavy Crude Oil ($/bbl)	(0.81)	(1.23)	(1.18)	(3.44)
Combined ($/boe)	(0.68)	(1.06)	(0.79)	(4.36)
Netback Received(4)(6)				

	Quarter Ended			
	September 30, 2020	December 31, 2020	March 31, 2021	June 30, 2021
Conventional Natural Gas ($/mcf)[8]	--	--	--	3.66
Shale Gas ($/mcf)	1.62	(0.13)	2.75	2.40
Natural Gas Liquids ($/bbl)				
Condensate[2][5]	25.64	448.04	59.72	52.36
Other NGL	6.15	15.76	17.60	25.07
Total NGL[5]	10.46	118.15	36.85	44.65
Tight Oil (bbl/d)[3][8]	27.10	28.25	46.71	51.59
Heavy Crude Oil ($/bbl)	18.52	19.99	33.49	40.01
Combined ($/boe)	19.51	27.40	35.91	27.95

Notes:

(1) Working interest before the deduction of royalties.

(2) Comprised of the condensate that is extracted in the field or that is otherwise sold separately from other NGL in Alberta and some condensate entrained in the NGL delivered to fractionation facilities.

(3) 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 production by product on a pro-rata basis.

(4) Calculated by management by subtracting royalties, operating and transportation costs from sales revenue. These figures have not been adjusted for hedging gains or losses or processing and third-party income. As natural gas liquids are produced concurrently with shale gas and conventional natural gas using shared infrastructure, the netback of any individual product should not be evaluated in isolation. Netback does not have any standardized meaning and should not be used for the purposes of drawing comparisons among Kiwetinohk and other companies.

(5) During the fourth quarter of 2020, the reclassification of a Crown royalty on one well that was recorded in 2020 resulted in a refund in prior period Crown royalties of $300,000, net of the annual gas cost allowances estimate.

(6) The Company closed the acquisition of the Simonette Assets and gained control over Distinction due to a change of the board of directors on April 28, 2021. Production data includes consolidated data effective as of April 28, 2021.

(7) Due to rounding, certain rows may not add exactly.

(8) At July 1, 2021 a product type reclassification was made from Conventional Natural Gas to Shale Gas, and from Light and Medium Crude Oil to Tight Oil for certain assets. Historical numbers are applied in the table above retroactively.

(9) Transportation costs for NGLs and tight oil have been allocated on a pro-rata basis.

The following table indicates the average gross daily production from each of the important fields, aggregated by area, for the twelve-month period ended July 1, 2021.

	Conventional Natural Gas	Shale Gas	NGL	Tight Oil	Heavy Crude Oil	Total
	(mmcf/d)	*(mmcf/d)*	*(bbl/d)*	*(bbl/d)*	*(bbl/d)*	*(boe/d)*
Fox Creek Region[1]	0.6	8.3	1,035.0	11.0	-	2,526.8
Placid	0.6	3.1	414.6	-	-	1,024.8
Simonette	-	5.2	620.4	11.0	-	1,502.0
West Simonette	-	-	-	-	-	-
Thorhild Region	-	-	-	-	30.3	30.3
West Central Alberta Region	-	1.2	117.2	359.9	-	679.8
Misc.	-	-	-	-	-	-
TOTAL[1] [2]	0.6	9.5	1,152.2	370.9	30.3	3,236.9

Note:

(1) Numbers may not add due to rounding.

(2) Production data includes consolidated data effective the date of the Corporation's business combinations with Simonette and **acquisition of control of** Distinction which was April 28, 2021.

DIVIDENDS AND DIVIDEND POLICY

Kiwetinohk has not historically paid any dividends on the Common Shares but may, at the discretion of the Board, pay dividends on the Common Shares in the foreseeable future. The future payment of dividends will be dependent upon the financial requirements of Kiwetinohk to fund future growth, the financial condition of Kiwetinohk and other factors the Board may consider appropriate in the circumstances.

Future capital allocation decisions will be determined solely by the Board, within the latitude afforded by: (a) requirements to fund sustaining capital costs required to maintain a base level of business operations; (b) opportunities to deploy growth capital to be used for organic and/or inorganic opportunities which present compelling returns on invested capital; (c) disciplined maintenance of a robust balance sheet through targeted debt to cash flow metrics; and (d) share repurchases and/or dividend payments to Shareholders. The Board will develop and modify from time to time, at its discretion, objectives for deployment of capital, raising of debt and equity and paying of dividends or buying back shares taking into account shareholder feedback.

Under the Credit Agreement, the Company is permitted to pay dividends or any other distributions provided that: (a) prior to and after giving effect to such distributions, Kiwetinohk shall have at least 50% undrawn on the Credit Agreement; (b) prior to and after giving effect to such distributions, Kiwetinohk shall have a debt to EBITDA ratio (as defined in the Credit Agreement) of not greater than 1.0 to 1.0 (calculated on a consolidated basis with debt on such date and EBITDA on a twelve month rolling basis for the applicable period ending on the last day of the then most recently completed fiscal quarter); and (c) there is no existing default or event of default that would occur as a result of such dividend or distribution.

The payment of dividends by the Company is also governed by the liquidity and insolvency tests described in the CBCA. Pursuant to the CBCA, in order to pay a dividend, the Company must, after such payment, be able to pay its liabilities as they become due and the realizable value of its assets must be greater than its liabilities and the legal stated capital of its outstanding securities.

CAPITAL STRUCTURE

Share Capital

The authorized share capital of the Company as of the date hereof consists of an unlimited number of Common Shares. As of the date of this AIF, there are 43,598,103 Common Shares issued and outstanding.

Common Shares

The Common Shares have the following rights, privileges, restrictions and conditions:

> ***Voting Rights***: Holders of Common Shares are entitled to receive notice of, to attend and to vote at all meetings of Shareholders and are entitled to one vote per Common Share held at such meetings, except meetings of holders of another class or one or more series of another class of shares who are entitled to vote separately as a class at such meeting.
>
> ***Dividends***: Holders of Common Shares are entitled to receive dividends if, as and when declared by the Board, such dividends or other distributions as may be declared thereon by the Board from time to time.
>
> ***Distribution***: In the event of any voluntary or involuntary liquidation, dissolution or winding-up of the Company or any other distribution of the Company's assets among its shareholders for the purpose of winding-up its affairs, holders of Common Shares shall share equally, share for share, in the property of the Company.

Options

The following table sets forth certain information in respect of Options that are outstanding as of the date hereof. See also "*Statement of Executive Compensation*" in Appendix "D" hereto.

Group (Number in Group)	**Common Shares Under Option (#)**	**Exercise Price per Common Share ($)(weighted average)**	**Market Value of Common Shares Under Option ($)[(1)]**	**Expiration Date[(2)]**
Current and former executive officers of Kiwetinohk ("**Executives**") (9 persons) [(3)]	1,112,980	$10.00	11,129,800	October 3, 2025 – November 23, 2028

Group (Number in Group)	Common Shares Under Option (#)	Exercise Price per Common Share ($)(weighted average)	Market Value of Common Shares Under Option ($)[(1)]	Expiration Date[(2)]
Current and former directors of Kiwetinohk, excluding Executives (9 persons) [(3)]	474,171	$10.00	4,741,710	October 3, 2025 – November 23, 2028
Current and former employees of Kiwetinohk (49 persons)	1,668,286	$10.00	16,682,860	October 3, 2025 – November 15, 2028
Total	**3,255,437**		**32,554,370**	

Notes:

(1) The market value of the Common Shares underlying these Options on both the date of grant and the date specified above is not readily ascertainable given that the Common Shares are not and have never been publicly traded. The value presented is based on an assumed price of $10.00 per Common Share, which is supported by reference to Kiwetinohk's recent financing activities. See "*Prior Sales*".

(2) Options were granted with seven-year exercise periods.

(3) Includes Distinction stock options assumed in connection with the Business Combination.

Performance Warrants

The following table sets forth certain information in respect of Performance Warrants that are outstanding as of the date hereof. See also "*Statement of Executive Compensation*" in Appendix "D" hereto.

Group (Number in Group)	Common Shares Under Performance Warrant (#)	Exercise Price per Common Share ($)(weighted average)[(1)]	Market Value of Common Shares Under Performance Warrant ($)[(2)]	Expiration Date[(3)]
Current and former Executives (9 persons)	3,592,465	$20.00	35,924,650	October 3, 2025 – November 23, 2026
Current and former directors of Kiwetinohk, excluding Executives (9 persons)	754,120	$20.00	7,541,200	October 3, 2025 – November 23, 2026
Current and former employees of Kiwetinohk (49 persons)	3,491,405	$20.00	34,914,050	October 3, 2025 – October 25, 2026
Total	**7,837,990**		**78,379,900**	

Notes:

(1) Reflects the range of applicable exercise prices per Common Share.

(2) The market value of the Common Shares underlying these Performance Warrants on both the date of grant and the date specified above is not readily ascertainable given that the Common Shares are not and have never been publicly traded. The value presented is based on an assumed price of $10.00 per Common Share, which is supported by reference to Kiwetinohk's recent financing activities. See "*Prior Sales*".

(3) Performance Warrants were granted on October 3, 2018 and on January 4, 2021 in each case with seven-year exercise periods. Performance Warrants granted subsequently had five-year exercise periods.

MARKET FOR SECURITIES

There is currently no market through which the Common Shares or any other securities of the Company may be sold. See "*Risk Factors*".

PRIOR SALES

The following table summarizes the issuances of Common Shares or securities convertible into Common Shares during 2021 and 2020. For further details, please see "*General Development of the Business – Three Year History*".

Date of Issuance	Number and Type of Securities	Issue Price per Security ($)	Aggregate Funds Received ($)
March 10, 2020	7,000 Stock Options	N/A	N/A
March 10, 2020	14,000 Performance Warrants	N/A	N/A
September 2, 2020	1,693,629 Common Shares[(1)]	$10.00	16,936,292
September 30, 2020	37,696 Common Shares[(2)]	$10.00	376,960
December 16, 2020	4,206,756 Common Shares[(1)]	$10.00	42,067,564
January 4, 2021	592,628 Stock Options[(3)]	N/A	N/A
January 4, 2021	1,183,856 Performance Warrants[(4)]	N/A	N/A
January 16, 2021	22,298 Common Shares[(5)]	$10.00	222,980
March 8, 2021	950,617 Common Shares[(1)]	$10.00	9,506,177
April 23, 2021	3,085,000 subscription receipts for Common Shares[(6)]	$10.00	30,850,000

Date of Issuance	Number and Type of Securities	Issue Price per Security ($)	Aggregate Funds Received ($)
April 28, 2021	2,899,960 Common Shares(1)	$10.00	28,999,607
April 29, 2021	7,500,000 Common Shares converted from promissory note(7)	$10.00	75,000,000
May 1, 2021	3,000 Stock Options	N/A	N/A
May 18, 2021	12,000 Stock Options	N/A	N/A
May 18, 2021	24,000 Performance Warrants	N/A	N/A
May 19, 2021	200,000 Common Shares(8)	$10.00	2,000,000
May 24, 2021	48,897 Common Shares(8)	$10.00	488,978
May 25, 2021	3,000 Stock Options	N/A	N/A
May 25, 2021	6,000 Performance Warrants	N/A	N/A
June 1, 2021	12,000 Stock Options	N/A	N/A
June 1, 2021	24,000 Performance Warrants	N/A	N/A
June 7, 2021	14,500 Stock Options	N/A	N/A
June 7, 2021	29,000 Performance Warrants	N/A	N/A
June 10, 2021	6,448 Common Shares(9)	$10.00	64,483
June 28, 2021	700,502 Options(3)	N/A	N/A
June 28, 2021	3,799,641 Performance Warrants(4)	N/A	N/A
July 19, 2021	6,000 Stock Options	N/A	N/A
July 19, 2021	12,000 Performance Warrants	N/A	N/A
July 26, 2021	3,850 Stock Options	N/A	N/A
July 26, 2021	7,700 Performance Warrants	N/A	N/A
September 1, 2021	19,650 Stock Options	N/A	N/A
September 1, 2021	39,300 Performance Warrants	N/A	N/A
September 15, 2021	11,000 Stock Options(10)	N/A	N/A
September 15, 2021	22,000 Performance Warrants(10)	N/A	N/A
September 22, 2021	10,172,200 Common Shares(11)	N/A	N/A
September 22, 2021	39,000 Stock Options	N/A	N/A
September 22, 2021	78,000 Performance Warrants	N/A	N/A
October 25, 2021	15,000 Stock Options	N/A	N/A
November 1, 2021	7,500 Stock Options	N/A	N/A
November 11, 2021	15,000 Performance Warrants(12)	N/A	N/A
November 11, 2021	30,000 Performance Warrants(12)	N/A	N/A
November 15, 2021	3,500 Stock Options	N/A	N/A
November 15, 2021	7,000 Performance Warrants	N/A	N/A
November 23, 2021	30,000 Stock Options(13)	N/A	N/A
November 23, 2021	60,000 Performance Warrants(13)	N/A	N/A
November 23, 2021	260,000 Performance Warrants(14)	N/A	N/A

Notes:

(1) Issued pursuant to an equity call.
(2) Contractors paid in Common Shares.
(3) The Options have an exercise price of $10.00 per Common Share.
(4) The Performance Warrants have exercise prices in tranches ranging from $15.00 to $25.00 per Common Share, with a weighted average exercise price of $20.00 per Common Share.
(5) Consultant paid in Common Shares.
(6) Issued pursuant to subscription receipts that were converted to Common Shares on April 28, 2021.
(7) Issued pursuant to a promissory note that was converted to Common Shares on April 28, 2021, at a conversion price of $10.00 per Common Share.
(8) Issued pursuant to a private placement of Common Shares.
(9) Contractor bonus pool paid in Common Shares.
(10) Issued to Janet Annesley in connection with her appointment as Chief Sustainability Officer.
(11) Issued in connection with the completion of the Business Combination.
(12) Issued to Mike Backus in connection with his appointment as Chief Operating Officer (Upstream Division).
(13) Issued to Tim Schneider, Steve Sinclair and Beth Reimer-Heck in connection with joining the Board of Directors.
(14) Issued to certain executives of the Company.

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

The following table sets forth, as of the date hereof, the number of securities of each class of securities of Kiwetinohk held, to the knowledge of the Company, in escrow or that is subject to a contractual restriction on transfer and the percentage that number represents of the outstanding securities of that class.

Designation of Class	Number of Securities Held in Escrow or that are Subject to a Contractual Restriction on Transfer	Percentage of Class(1)
Common Shares	7,301,966	16.75%

Note:

(1) These shares are subject to a Section 116 withholding escrow under the Tax Act in connection with the Business Combination, based on 43,598,103 Common Shares issued and outstanding as of the date hereof.

Pursuant to the Investment Rights Agreement (ARC) and Investment Rights Agreement (Luminus), ARC and Luminus have each agreed that during the period commencing on September 22, 2021 until (i) May 31, 2022, or (ii) if prior to May 31, 2022 the TSX Listing Date has occurred, such date that is 180 days following the TSX Listing Date, they will not, directly or indirectly, without the prior written consent of Kiwetinohk, sell any option to purchase any equity securities of Kiwetinohk or other securities convertible into equity securities of Kiwetinohk held by ARC or Luminus on September 22, 2021 to any Person other than an Affiliate.

PRINCIPAL HOLDERS OF VOTING SECURITIES

To the knowledge of the directors and officers of Kiwetinohk, as of the date of this AIF, no person or company beneficially owns, or exercises control or direction over, directly or indirectly, more than 10% of the voting rights attached to all of the outstanding Common Shares, other than as set forth below:

Name	Number of Common Shares	Percentage of Common Shares
ARC[(1)]	27,504,624	63.1%
Luminus[(2)]	5,202,334	11.9%

Notes:

(1) Such Common Shares are owned both of record and beneficially by ARC.

(2) Such Common Shares are owned both of record and beneficially by Luminus.

The Company entered into an investment rights agreement with each of ARC and Luminus, respectively, in connection with the Business Combination (the "**Investment Rights Agreement (ARC)**" and the "**Investment Rights Agreement (Luminus)**", respectively).

Investment Rights Agreement (ARC)

Pursuant to the Investment Rights Agreement (ARC), assuming that there are a total of nine directors elected to the Board as is currently the case, ARC will have the right to designate: (a) one director nominee for election to the Board for so long as ARC exercises control or direction over 10% or more of the Common Shares; (b) two director nominees for election to the Board for so long as ARC exercises control or direction over 25% or more of the Common Shares; and (c) three director nominees for election to the Board for so long as ARC exercises control or direction over 40% or more of the Common Shares, and if so, one of such nominees shall be the Chair unless ARC otherwise agrees. If the size of the Board is changed, the foregoing rights shall be adjusted accordingly. For so long as ARC is entitled to have a nominee on the Board, Kiwetinohk shall take such action as may be necessary to ensure that the nominee of ARC is either appointed to or granted observer rights on each committee of directors formed by the Board. At this time, there are three ARC nominees on the Board.

For so long as ARC owns or exercises control or direction over 10% or more of the outstanding Common Shares or is otherwise considered a "control person" under Applicable Securities Laws, ARC has the right to require Kiwetinohk to qualify Common Shares held by ARC and its affiliates for distribution by way of a secondary offering prospectus (which may include the use of a short form or shelf prospectus, if the Company qualifies to use such procedures) prepared in accordance with Applicable Securities Laws (an "**ARC Demand Registration**"). ARC is entitled to a maximum of six ARC Demand Registrations in total, and a maximum of two ARC Demand Registration in any calendar year; provided, however, that the aggregate market value of Common Shares specified in each request for an ARC Demand Registration is not less than $10,000,000 (or, if less than $10,000,000, then such securities must represent at least one-half of the total Common Shares then held by ARC). Kiwetinohk will be responsible for paying all fees and expenses incurred in connection with such ARC Demand Registration to the extent permitted by applicable law, provided that ARC shall pay the fees and expenses of its own counsel and the underwriting discounts, commissions and similar fees and transfer taxes applicable to Common Shares held by ARC included in connection with each ARC Demand Registration. ARC will have the right to select the investment banker(s) and manager(s) to administer the offering of the Common Shares which are the subject of an ARC Demand Registration.

For so long as ARC owns or exercises control or direction over 10% or more of the outstanding Common Shares or is otherwise considered a "control person" under Applicable Securities Laws, ARC may request that Kiwetinohk include Common Shares held by ARC in any qualification or registration of Common Shares by Kiwetinohk or another securityholder of Kiwetinohk under Applicable Securities Laws (an "**ARC Piggyback Registration**"). Kiwetinohk must cause to be included in the ARC Piggyback Registration all Common Shares that ARC requests to be included; provided, however, that if an ARC Piggyback Registration is a distribution of securities by Kiwetinohk and the lead underwriter(s) or agent(s) advise that the total number of securities requested to be included in the distribution exceeds the number which can be sold in an orderly manner in such offering within a price range acceptable to Kiwetinohk and ARC, each acting reasonably (the "**Maximum Offering Size**"), Kiwetinohk will include in such distribution: (a) first, as many of the Common Shares (or other securities) that Kiwetinohk proposes to sell from treasury as will not cause the distribution to exceed the Maximum Offering Size, and (b) second, (i) if Luminus is not entitled at the relevant time to exercise "piggyback" rights under the Investment Rights Agreement (Luminus), then as many of ARC's Common Shares requested to be included in such distribution as will not cause the distribution to exceed the Maximum Offering Size, or (ii) if Luminus is entitled at the relevant time to exercise "piggyback" rights under the Investment Rights Agreement (Luminus), then pro rata as many of ARC's Common Shares requested to be included in such distribution and as many of Luminus' Common Shares requested to be included in such distribution as will not cause the offering to exceed the Maximum Offering Size. If an ARC Piggyback Registration is to occur in conjunction with a secondary distribution on behalf of another shareholder or shareholders of Kiwetinohk and the lead underwriter(s) or agent(s) advise that the total number of securities requested to be included in the distribution exceeds the number which can be sold in an orderly manner in such offering within a price range acceptable to that other shareholder or shareholders and Kiwetinohk, then the number of Common Shares requested to be included by ARC will be included in such distribution pro rata (based upon each securityholder's (including ARC's) relative security holdings to each other) with the Common Shares or other securities requested to be included in such distribution. Kiwetinohk shall have the right to select the investment banker(s) and manager(s) to administer the offering from treasury and the Common Shares which are subject to the ARC Piggyback Registration. The expenses pursuant to the ARC Piggyback Registration will be paid by Kiwetinohk to the extent permitted by applicable law, provided that ARC shall pay the fees and expenses of its own counsel and the underwriting discounts, commissions and similar fees and transfer taxes applicable to Common Shares held by ARC included in connection with each ARC Piggyback Registration.

Upon receipt of a request from ARC for an ARC Demand Registration or an ARC Piggyback Registration, Kiwetinohk will use its reasonable commercial efforts to effect the distribution of the Common Shares which are the subject of an ARC Demand Registration or an ARC Piggyback Registration. Kiwetinohk is obligated to indemnify ARC and its affiliates participating in such registration (and their respective managers/general partners and their respective directors, officers, employees, shareholders, partners and agents) against all losses, claims, damages, liabilities and expenses caused by any untrue or alleged untrue statement of a material fact contained in any preliminary prospectus, final prospectus, shelf prospectus, or any amendment thereof or supplement thereto, or any omission or alleged omission to state therein a material fact required to be stated therein or necessary to make any statement therein not misleading, except insofar as the same are contained in any information relating solely to an entity comprising ARC or its affiliates furnished in writing to Kiwetinohk by such entity participating in the ARC Demand Registration or ARC Piggyback Registration expressly for use therein or caused by such entity's failure to deliver a copy of the prospectus or any amendments or supplements thereto after Kiwetinohk has furnished the applicable entity with a sufficient number of copies of same.

The Investment Rights Agreement (ARC) will terminate at the time that ARC has owned, or exercised control or direction over, an aggregate of less than 10% of the Common Shares over a period of three consecutive months.

Investment Rights Agreement (Luminus)

Pursuant to the Investment Rights Agreement (Luminus), Luminus will have the right to designate one director nominee for election to the Board for so long as Luminus exercises control or direction over 10% or more of the Common Shares; provided that until the listing and posting of Common Shares for trading on the TSX, Luminus shall be entitled to such right without regard to the requirement for Luminus to own or exercise control over 10% of more of the Common Shares. For so long as Luminus is entitled to have a nominee on the Board, Kiwetinohk shall take such action as may be necessary to ensure that the nominee of Luminus is either appointed to or granted observer rights on each committee of directors formed by the Board. At this time, there is one Luminus nominee on the Board.

After the expiration of the hold period, being the later of (a) May 31, 2022, or (b) if the TSX Listing Date is prior to May 31, 2022, the date that is 180 days following the TSX Listing Date, for so long as Luminus owns or exercises control or direction over 10% or more of the outstanding Common Shares or is otherwise considered a "control person" under Applicable Securities Laws, Luminus has the right to require Kiwetinohk to qualify Common Shares held by Luminus and its affiliates for distribution by way of a secondary offering prospectus prepared in accordance with Applicable Securities Laws (a "**Luminus Demand Registration**"). Luminus is entitled to a maximum of two Luminus Demand Registrations in total, and a maximum of one Luminus Demand Registration in any calendar year; provided, however, that the aggregate market value of Common Shares specified in each request for a Luminus Demand Registration is not less than $10,000,000 (or, if less than $10,000,000, then such securities must represent at least one-half of the total Common Shares then held by Luminus). Kiwetinohk will be responsible for paying all fees and expenses incurred in connection with such Luminus Demand Registration to the extent permitted by applicable law, provided that Luminus shall pay the fees and expenses of its own counsel and the underwriting discounts, commissions and similar fees and transfer taxes applicable to Common Shares held by Luminus included in connection with each Luminus Demand Registration. Luminus will have the right to select the investment banker(s) and manager(s) to administer the offering of the Common Shares which are the subject of a Luminus Demand Registration.

For so long as Luminus owns or exercises control or direction over 10% or more of the outstanding Common Shares or is otherwise considered a "control person" under Applicable Securities Laws, Luminus may request that Kiwetinohk include Common Shares held by Luminus in any qualification or registration of Common Shares by Kiwetinohk or another securityholder of Kiwetinohk under Applicable Securities Laws (a "**Luminus Piggyback Registration**"). Kiwetinohk must cause to be included in the Luminus Piggyback Registration all Common Shares that Luminus requests to be included; provided, however, that if a Luminus Piggyback Registration is a distribution of securities by Kiwetinohk and the lead underwriter(s) or agent(s) advise that the total number of securities requested to be included in the distribution exceeds the Maximum Offering Size, Kiwetinohk will include in such distribution: (a) first, as many of the Common Shares (or other securities) that Kiwetinohk proposes to sell from treasury as will not cause the distribution to exceed the Maximum Offering Size; and (b) second, pro rata as many of Luminus' Common Shares requested to be included in such distribution and as many Common Shares held by other securityholders of Kiwetinohk who at such time have registration, distribution or similar qualification rights and who have requested to include their Common Shares in such distribution, as will not cause the offering to exceed the Maximum Offering Size. If a Luminus Piggyback Registration is to occur in conjunction with a secondary distribution on behalf of another shareholder or shareholders of Kiwetinohk and the lead underwriter(s) or agent(s) advise that the total number of securities requested to be included in the distribution exceeds the number which can be sold in an orderly manner in such offering within a price range acceptable to that other shareholder or shareholders and Kiwetinohk, then the number of Common Shares requested to be included by Luminus will be included in such distribution pro rata (based upon each securityholder's (including Luminus') relative security holdings to each other) with the Common Shares or other securities requested to be included in such distribution. Kiwetinohk shall have the right to select the investment banker(s) and manager(s) to administer the offering from treasury and the Common Shares which are subject to the Luminus Piggyback Registration. The expenses pursuant to the Luminus Piggyback Registration will be paid by Kiwetinohk to the extent permitted by applicable law, provided that Luminus shall pay the fees and expenses of its own counsel and the underwriting discounts, commissions and similar fees and transfer taxes applicable to Common Shares held by Luminus included in connection with each Luminus Piggyback Registration.

Upon receipt of a request from Luminus for a Luminus Demand Registration or a Luminus Piggyback Registration, Kiwetinohk will use its reasonable commercial efforts to effect the distribution of the Common Shares which are the subject of a Luminus Demand Registration or a Luminus Piggyback Registration. Kiwetinohk is obligated to indemnify Luminus and its affiliates participating in such registration (and their respective managers/general partners and their respective directors, officers, employees, shareholders, partners and agents) against all losses, claims, damages, liabilities and expenses caused by any untrue or alleged untrue statement of a material fact contained in any preliminary prospectus, final prospectus, shelf prospectus, or any amendment thereof or supplement thereto, or any omission or alleged omission to state therein a material fact required to be stated therein or necessary to make any statement therein not misleading, except insofar as the same are contained in any information relating solely to an entity comprising Luminus or its affiliates furnished in writing to Kiwetinohk by such entity participating in the Luminus Demand Registration or Luminus Piggyback Registration expressly for use therein or caused by such entity's failure to deliver a copy of the prospectus or any amendments or supplements thereto after Kiwetinohk has furnished the applicable entity with a sufficient number of copies of same.

The Investment Rights Agreement (Luminus) will terminate at the time that Luminus has owned, or exercised control or direction over, an aggregate of less than 10% of the Common Shares.

DIRECTORS AND OFFICERS

The name, city of residence, and principal occupation during the last five years of each of the directors and officers of the Company, as of the date of this AIF, are set forth in the following table.

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since	Number and Percentage of Common Shares Held
Kevin Brown Calgary, AB Canada	Director (Chair) • *Audit Committee Member* • *Governance and Nominating Committee Member*	Kevin Brown is the Co-Chairman and Director of ARC Financial Corp. He has been with ARC Financial Corp. since 1989.	December 2018	--(1)(2)
Patrick Carlson Calgary, AB Canada	Chief Executive Officer and Director • *Reserves Committee Member* • *Sustainability Committee Member*	Patrick Carlson has been the Chief Executive Officer of Kiwetinohk since February 12, 2018 and President and Chief Executive Officer of Distinction since April 2021. Prior to founding Kiwetinohk, he was the Chief Executive Officer and a director of Seven Generations Energy Ltd. until his retirement as CEO in June 2017 and his resignation from the board in May 2018.	February 2018	1,000,400(3) (2.30%)
Leland Corbett Calgary, AB Canada	Director • *Compensation Committee Member* • *Sustainability Committee Member* • *Governance and Nominating Committee Member*	Leland Corbett is a partner at Stikeman Elliott LLP. He has been at Stikeman Elliott LLP since 1994.	August 2018	30,838 (0.07%)
Kaush Rakhit Calgary, AB Canada	Director • *Reserves Committee Member* • *Compensation Committee Member*	Kaush Rakhit is the Chief Executive Officer of Canadian Discovery Ltd. He founded Rakhit Petroleum Consulting Ltd. in 1989, which purchased and merged with Canadian Discovery Ltd. in 2005.	August 2018	102,000 (0.23%)
Nancy Lever Calgary, AB Canada	Director • *Reserves Committee Member* • *Sustainability Committee Member* • *Compensation Committee Member*	Nancy Lever is an Advisor at ARC Financial Corp. She has been with ARC Financial Corp. since 1993.	September 2021	--(1)

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since	Number and Percentage of Common Shares Held
Steve Sinclair Calgary, AB Canada	Director • *Audit Committee Member (Chair)* • *Compensation Committee Member*	Steve Sinclair is retired. He is a Director and Audit Chair of TransGlobe Energy Corporation and of Deltastream Energy Corp.	September 2021	2,882 (0.00%)
Timothy Schneider Houston, TX USA	Director • *Audit Committee Member* • *Governance and Nominating Committee Member*	Timothy Schneider is an energy sector professional having managed investments in both public and private markets. He has experience as an industry executive and member of public and private boards. Previous experience includes Citadel (2014-2016), SAC Capital (2011-2014) and Triatlantic (2008-2011).	September 2021	91,588 (0.23%)
Beth Reimer-Heck Calgary, AB Canada	Director • *Audit Committee Member* • *Sustainability Committee Member* • *Governance and Nominating Committee Member*	Beth Reimer-Heck has been senior counsel at BLG LLP from 2009 to present. Ms. Reimer-Heck is also an advisory board member of Saskatchewan Mines and Minerals Inc. and a director of United Way, Calgary.	September 2021	638 (0.00%)
Jakub Brogowski Calgary, AB Canada	Chief Financial Officer	Jakub Brogowski has been the Chief Financial Officer of Kiwetinohk since December 2018 and Chief Financial Officer of Distinction since April 2021. Prior thereto, he spent over 15 years in various roles across the oil and gas industry, including an executive role, consulting and investment banking and energy advisory roles in Canada and the UK.	N/A	14,000(4) (0.03%)
Mike Backus Calgary, AB Canada	Chief Operating Officer, Upstream	Mike Backus was appointed as Chief Operating Officer of the Company effective October 25, 2021, and brings over 25 years of industry experience in engineering and operational finance to Kiwetinohk, both domestically and internationally. Prior to this role, Mr. Backus held executive roles at Painted Pony Energy, CNOOC International, and its predecessor, Nexen Inc.	N/A	--
Janet Annesley Calgary, AB Canada	Chief Sustainability Officer	Janet Annesley joined Kiwetinohk as Chief Sustainability Officer in September 2021, having previously held senior executive posts at Husky Energy and Natural Resources Canada. Janet's background includes work at Shell Canada in heavy oil and carbon and capture and storage, and at the Canadian Association of Petroleum Producers.	N/A	--
Sue Kuethe Calgary, AB Canada	Executive Vice President, Land and Community Inclusion	Sue Kuethe has been the Executive Vice President, Land and Community Inclusion of Kiwetinohk since March 2018. Prior thereto, she was Advisor in Aboriginal Relations to the Social Licence Consortium. Prior thereto, Sue served as VP Land and Community Affairs at Koch Oil Sands Operating ULC and Koch Exploration Company LLC.	N/A	21,200(5) (0.05%)
Kurt Molnar Calgary, AB Canada	Senior Vice President, Business Development	Kurt Molnar has been the Senior Vice President, Business Development of Kiwetinohk since October 2019. Prior thereto, he was an E&P equities analyst at Raymond James Financial.	N/A	26,298(6) (0.06%)
Mike Hantzsch Calgary, AB Canada	Senior Vice President, Midstream and Market Development	Mike Hantzsch has been the Senior Vice President, Midstream and Market Development of Kiwetinohk since February 2020. Prior thereto, he was Chief Operating Officer, LNG of Kiwetinohk since May 2018. Prior thereto, he was Senior Vice President, Canada of Meritage Midstream ULC from May 2016 to February 2017.	N/A	39,000(7) (0.10%)
Lisa Wong Calgary, AB Canada	Senior Vice President, Business Systems	Lisa Wong has been the Vice President, Business Systems since February 2018. Prior thereto, she was Coordinator of Business Systems with Seven Generations Energy Ltd.	N/A	101,200 (0.23%)
Farid Shirkavand Calgary, AB Canada	Vice President	Farid Shirkavand has been the Vice President, Drilling since February 2018. Prior thereto, he was Director, Drilling with Seven Generations Energy Ltd.	N/A	8,700 (0.00%)

Notes:

(1) Mr. Brown and Ms. Lever are officers and/or employees of ARC Financial Corp. Certain ARC entities that are affiliates of ARC Financial Corp. collectively hold 27,504,624 Common Shares.

(2) Mr. Brown does not own any Common Shares. Shares previously registered in Mr. Brown's name have been assigned to ARC Financial Corp. and entities that it manages.

(3) Patrick Carlson's wife, Darlene Constance Carlson, who is a part-time employee of Kiwetinohk, holds 500,200 Common Shares. Patrick Carlson holds the other 500,200 Common Shares.

(4) Jakub Brogowski's wife, Claudia Huynh, holds the 12,000 Common Shares in her name.
(5) Sue Kuethe's husband, David Stelck, holds 10,000 Common Shares in his name. Sue Kuethe holds the other 11,200 Common Shares.
(6) Kurt Molnar's wife, Cara Molnar holds 2,000 Common Shares.
(7) Mike Hantzsch's wife, Petronella Hantzsch, holds 19,500 Common Shares in her name. Mike Hantzsch holds the other 19,500 Common Shares.

All of the Company's directors' terms of office will expire at the earliest of their resignation, the close of the next annual Shareholder meeting called for the election of directors, or on such other date as they may be removed according to the CBCA. The directors devote the amount of time as is required to fulfill their obligations to the Company. The Company's officers are appointed by and serve at the discretion of the Board of Directors.

Share Ownership by Directors and Officers

As at December 31, 2020, the directors and officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, 763,880 Common Shares, representing approximately 4.1% of the then issued and outstanding Common Shares. As of the date of this AIF, the directors and officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, 1,438,744 Common Shares, representing approximately 3.3% of the currently issued and outstanding Common Shares.

Cease Trade Orders, Bankruptcies, Penalties or Sanctions

Cease Trade Orders and Bankruptcies

Other than as disclosed below, to the knowledge of the Company, no director or executive officer of the Company (nor any personal holding company of any of such persons) is, as of the date of this AIF, or was within ten years before the date of this AIF, a director, chief executive officer or chief financial officer of any company (including the Company), that while acting in that capacity:

(a) 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

(b) 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.

Other than as disclosed below, to the knowledge of the Company, no director or executive officer of the Company (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company:

(a) is, as of the date of this AIF, or has been within the ten years before the date of this AIF, a director or executive officer of any company (including the Company) 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; or

(b) has, within the ten years before the date of this AIF, 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.

Kaush Rahkit served as a director of Kinwest 2008 Energy Inc. at the time that it entered into bankruptcy proceedings on May 12, 2016.

Timothy Schneider was President and Chief Executive Officer of Distinction (formerly Delphi Energy Corp.) from October 2020 to April 2021 and served in such positions during Distinction's court-supervised CCAA proceedings that resulted in the restructuring of Distinction on October 16, 2020 pursuant to a CCAA plan of compromise and arrangement.

Penalties or Sanctions

To the knowledge of the Company, no director or executive officer of the Company (nor any personal holding company of any of such persons), or shareholder holding a sufficient number of securities of the Company to affect materially the control of the Company, has been subject to:

(a) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or

(b) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

Conflicts of Interest

Certain officers and directors of the Company are also officers and/or directors of other companies engaged in the crude oil and natural gas business generally. As a result, situations may arise where the interest of such directors and officers conflict with their interests as directors and officers of other companies. The resolution of such conflicts is governed by applicable corporate laws, which require that directors act honestly, in good faith and with a view to the best interests of the Company. Conflicts, if any, will be handled in a manner consistent with the procedures and remedies set forth in the CBCA. The CBCA provides that in the event that a director has an interest in a material contract or material transaction, whether made or proposed, the director shall disclose his interest in such contract or transaction to the Company and shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided by the CBCA.

Certain directors of the Company have existing business relationships with the Company. While such business relationships are not considered to be material to the Company, they could be perceived as giving rise to a conflict of interest. Related party transactions are further described in the Company's audited and unaudited financial statements and the accompanying notes, which may be viewed at the website maintained by the Canadian Securities Administrators at www.sedar.com.

See "*Risk Factors – Conflicts of Interest*".

INDEBTEDNESS OF DIRECTORS AND OFFICERS

Except as described in this AIF, the Company is not aware of any individuals who are either current or former executive officers, directors or employees of the Company, or any of its subsidiaries and who have indebtedness outstanding as of the date of this AIF (whether entered into in connection with the purchase of securities of the Company or otherwise) that is owing to: (a) the Company or any of its subsidiaries; or (b) another entity where such indebtedness is the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Company or any of its subsidiaries.

Except as described in this AIF and for: (a) indebtedness that has been entirely repaid on or before the date of this AIF; and (b) "routine indebtedness" (as defined in Form 51-102F5 of the Canadian Securities Administrators), the Company is not aware of any individuals who are, or who at any time since inception were, a director or executive officer of the Company, a proposed nominee for election as a director or an associate of any of those directors, executive officers or proposed nominees who are, or have been since the beginning of the most recently completed financial year, indebted to the Company or any of its subsidiaries, or whose indebtedness to another entity is, or at any time since the beginning of the most recently completed financial year has been, the subject of a guarantee, support agreement, letter of credit or other similar arrangement or understanding provided by the Company.

Upon closing of the Business Combination, certain directors and/or officers of Distinction incurred indebtedness to the Company for withholding tax on the surrender and exchange of their Distinction Restricted Share Units in an aggregate amount of approximately $0.6 million.

AUDIT COMMITTEE INFORMATION

Audit Committee Mandate

The Board has adopted a written mandate for the Audit Committee, which sets out the Audit Committee's responsibility for (among other things) reviewing Kiwetinohk's financial statements and Kiwetinohk's public disclosure documents containing financial information and reporting on such review to the Board, ensuring Kiwetinohk's compliance with legal and regulatory requirements, overseeing qualifications, engagement, performance and independence of Kiwetinohk's external auditors, and reviewing, evaluating and approving the internal control and risk assessment systems that are implemented and maintained by management. A copy of the Audit Committee mandate is attached to this AIF as Appendix "C".

Composition of the Audit Committee and Relevant Education and Experience

The Audit Committee consists of Steve Sinclair, Kevin Brown, Tim Schneider and Beth Reimer-Heck. Each of the members of the Audit Committee is considered "financially literate" and Mr. Sinclair, Mr. Schneider and Ms. Reimer-Heck are considered "independent" within the meaning of NI 52-110. Mr. Brown, by virtue of his roles with ARC, may be considered an "affiliated entity" of the Company but is exempt from the requirement that he be independent by virtue of section 3.3(2) of NI 52-110.

Kiwetinohk believes that each of the members of the Audit Committee possesses: (a) an understanding of the accounting principles used by Kiwetinohk to prepare its financial statements; (b) the ability to assess the general application of such accounting principles in connection with the accounting for estimates, accruals and provisions; (c) experience preparing, auditing, analyzing or evaluating financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of issues that can reasonably be expected to be raised by Kiwetinohk's financial statements, or experience actively supervising one or more individuals engaged in such activities; and (d) an understanding of internal controls and procedures for financial reporting.

For a summary of the experience of each member of the Audit Committee that is relevant to the performance of their responsibilities as a member of the Audit Committee, see "*Directors and Officers*".

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

The Audit Committee must pre-approve all non-audit services to be provided to Kiwetinohk by its external auditors, Deloitte LLP. The Audit Committee may delegate such pre-approval authority, if and to the extent permitted by law.

External Audit Service Fees

The following table summarizes the fees paid by Kiwetinohk to its external auditors, Deloitte LLP, for external audit and other services during the period indicated. The amounts disclosed exclude administrative charges.

	2019	2020
	($)	*($)*
Audit Fees[(1)]	60,990	134,820
Audit-Related Fees[(2)]	--	47,329
Tax Fees[(3)]	5,350	5,350
All Other Fees	63,438	--
Total	**129,778**	**187,499**

Notes:
(1) Represents the aggregate fees for services related to the audit of annual financial statements and review of quarterly financial statements.
(2) Represents aggregate fees for services provided in connection with equity and debt financings, including review of offering documents, completion of comfort letters for underwriters and attendance at due diligence meetings.
(3) Represents the aggregate fees billed for tax compliance, tax advice and tax planning.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no legal proceedings Kiwetinohk (including for the purposes of this section Distinction as a predecessor of Kiwetinohk) is or was a party to, or that any of its property is or was the subject of, during the Company's most recent financial year, nor are any such legal proceedings known to Kiwetinohk to be contemplated, that involves a claim for damages, exclusive of interest and costs, exceeding 10% of the current assets of the Company.

There are no: (a) penalties or sanctions imposed against Kiwetinohk by a court relating to securities legislation or by a securities regulatory authority since Kiwetinohk's inception; (b) other penalties or sanctions imposed by a court or regulatory body against Kiwetinohk that would likely be considered important to a reasonable investor in making an investment decision; or (c) settlement agreements Kiwetinohk entered into before a court relating to securities legislation or with a securities regulatory authority since Kiwetinohk's inception.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as otherwise set out herein, there is no material interest, direct or indirect, of any: (a) director or executive officer of Kiwetinohk; (b) person or company that beneficially owns, or controls or directs, directly or indirectly, more than 10% of any class or series of Kiwetinohk's voting securities; or (c) associate or affiliate of any of the persons or companies referred to in (a) or (b) above in any transaction within three years before the date of this AIF that has materially affected or is reasonably expected to materially affect Kiwetinohk.

TRANSFER AGENT AND REGISTRAR

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

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts that the Company has entered into prior to the date of this AIF, which can reasonably be regarded as presently material, are the following:

(a) the Credit Agreement;

(b) the Investment Rights Agreement (ARC); and

(c) the Investment Rights Agreement (Luminus).

Copies of the foregoing and the articles and by-laws of the Company are available under the Company's profile on the website maintained by the Canadian Securities Administrators at www.sedar.com.

INTERESTS OF EXPERTS

GLJ and McDaniel are named as having prepared or certified a statement, report, valuation or opinion described or included herein directly and whose profession or business gives authority to the statement, report, valuation or opinion, in each case with respect to Kiwetinohk. To the knowledge of Kiwetinohk, as of the date of this AIF, each of GLJ and McDaniel owns beneficially, directly or indirectly, less than 1% of the outstanding Common Shares of Kiwetinohk or any associate or affiliate thereof. Deloitte LLP is independent of the Company within the meaning of the rules of professional conduct of the Chartered Professional Accountants of Alberta.

ADDITIONAL INFORMATION

Additional information relating to the Company including the Joint Information Circular in respect of the Business Combination can be found on the SEDAR website at www.sedar.com. Additional financial information is provided in the audited consolidated financial statements and Management's Discussion and Analysis of the Company for the years ended December 31, 2020 and 2019, which are included in the Joint Information Circular accessible on the SEDAR website at www.sedar.com.

APPENDIX "A"

Glossary, Selected Abbreviations, and Selected Conversions

Glossary

In this AIF, unless otherwise indicated or the context otherwise requires, the following terms have the meaning set forth below:

"**2019 Regulations**" means the Indian Oil and Gas Regulations, SOR/2019-196, as promulgated under the IOGA.

"**2021 Pro Forma Reserves Report**" means the independent reserves report prepared by McDaniel dated July 16, 2021 evaluating the reserves attributable to certain of the assets of Kiwetinohk and its subsidiaries as at July 1, 2021 assuming completion of the Business Combination and an effective date of July 1, 2021. The related Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor and Report of Management and Directors on Oil and Gas Disclosure are attached hereto as Appendices "G" and "H" to the AIF, respectively.

"**2020 Kiwetinohk Reserves Report"** means the independent reserves report prepared by McDaniel dated January 21, 2021, evaluating the reserves attributable to certain of the assets of Kiwetinohk and its subsidiaries as at December 31, 2020. The related Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor and Report of Management and Directors on Oil and Gas Disclosure are attached as Appendices "G" and "H" to the AIF, respectively.

"**2020 Distinction Reserves Report**" means the independent reserves report prepared by GLJ dated March 5, 2021, evaluating the reserves attributable to certain of the assets of Distinction and its subsidiaries as at December 31, 2020. The related Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor and Report of Management and Directors on Oil and Gas Disclosure are attached as Appendices "G" and "H" to the AIF, respectively.

"**2020 Reserves Reports**" means, collectively, the 2020 Kiwetinohk Reserves Report, the 2020 Distinction Reserves Report and the 2020 Simonette Assets Reserves Report.

"**2020 Simonette Assets Reserves Report**" means the independent reserves report prepared by McDaniel dated January 21, 2021, evaluating the reserves attributable to the Simonette Assets as at December 31, 2020. The related Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor and Report of Management and Directors on Oil and Gas Disclosure are attached as Appendices "G" and "H" to the AIF, respectively.

"**ABC**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Liability Management Rating Program – Alberta*".

"**ABCA**" means the *Business Corporations Act* (Alberta), RSA 2000, c B-9, as amended, including the regulations thereunder.

"**AB LFP**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Liability Management Rating Program – Alberta*".

"**AB LMF**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Liability Management Rating Program – Alberta*".

"**AB LLR Program**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Liability Management Rating Program – Alberta*".

"**AB LMR Program**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Liability Management Rating Program – Alberta*".

"**AB OWL Program**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Liability Management Rating Program – Alberta*".

"**AECO**" means the AECO C spot price, the Alberta natural gas trading price.

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

"**AESO**" means the Alberta Electric System Operator.

"**Affiliate**" has the meaning given to it in NI 45-106.

"**Alberta Methane Regulations**" means the Methane Emission Reduction Regulations, Alta Reg 244/2018, as promulgated under the *Environmental Protection and Enhancement Act,* RSA 2000, c E-12, as amended.

"**Alliance**" means Alliance Pipeline Limited Partnership.

"**Alliance Pipeline**" means the transcontinental pipeline network owned by Alliance, as more particularly described under the heading "*Description of the Business – Overview of Oil and Natural Gas Properties – Midstream, Marketing and Transportation Arrangements – Alliance Pipeline*".

"**AACE**" means American Association of Cost Engineering.

"**Annual Information Form**" or "**AIF**" has the meaning ascribed thereto under the heading "*Presentation of Information and Exchange Rate Information*".

"**AAPL**" American Association of Professional Landmen.

"**Applicable Securities Laws**" means all applicable securities laws, the respective regulations, rules and orders made thereunder, and all applicable policies and notices issued by the securities regulatory authorities in Canada.

"**ARC**" means ARC Equity Management (Fund 8) Ltd. (as the general partner of ARC Equity Management (Fund 8) Limited Partnership, as the general partner of ARC Energy Fund 8 Canadian Limited Partnership, ARC Energy Fund 8 United States Limited Partnership, ARC Energy Fund 8 International Limited Partnership and ARC Capital 8 Limited Partnership) and ARC Equity Management (Fund 9) Ltd. (as the general partner of ARC Energy Fund 9 Canadian Limited Partnership, ARC Energy Fund 9 United States Limited Partnership, ARC Energy Fund 9 International Limited Partnership and ARC Capital 9 Limited Partnership).

"**ARC Demand Registration**" has the meaning ascribed thereto under the heading "*Principal Holders of Voting Securities – Investment Rights Agreement (ARC)*".

"**ARC Piggyback Registration**" has the meaning ascribed thereto under the heading "*Principal Holders of Voting Securities – Investment Rights Agreement (ARC)*".

"**AUC**" means the Alberta Utilities Commission.

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

"**Balancing Pool**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Power Industry – Alberta*".

"**BCEAO**" means the British Columbia Environmental Assessment Office.

"**BCOGC**" means the British Columbia Oil and Gas Commission.

"**BC LMR Program**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Liability Management Rating Program – British Columbia*".

"**Board**" or "**Board of Directors**" means the board of directors of the Company.

"**Business Combination**" means the business combination of Kiwetinohk and Distinction which occurred on or about September 22, 2021, pursuant to the terms and conditions set out in the Business Combination Agreement.

"**Business Combination Agreement**" means the business combination agreement dated June 28, 2021 between Kiwetinohk and Distinction.

"**Capital Warrants**" means the capital warrants of Kiwetinohk granted to certain employees, directors and consultants of Kiwetinohk, all of which terminated on completion of the Business Combination.

"**CAPL**" Canadian Association of Petroleum Landmen.

"**CBCA**" means the Canada Business Corporations Act, R.S.C. 1985, c. C-44, as amended, including the regulations promulgated thereunder.

"**CCAA**" means the *Companies' Creditors Arrangement Act* (Canada), RSC 1985, c C-36, as amended.

"**CCUS**" means carbon capture, utilization and storage.

"**CDS**" means CDS Clearing and Depository Services Inc.

"**CEAA 2012**" means the *Canadian Environmental Assessment Act, 2012*, S.C. 2012, c. 19, s. 52, as amended, including the regulations promulgated thereunder.

"**CEO**" means the Chief Executive Officer of the Company.

"**CER**" means the Canada Energy Regulator.

"**CERA**" means the *Canadian Energy Regulator Act*, S.C. 2019, c. 28, s. 10, as amended, including the regulations promulgated thereunder.

"**CFO**" means the Chief Financial Officer of the Company.

"**Chair**" and "**Chairperson**" means the chairperson of the Board of Directors.

"**CO_2**" means carbon dioxide.

"**CO_2E**" means **CO_2** equivalent.

"**CO_2 EOR**" means carbon dioxide enhanced oil recovery.

"**Code of Conduct**" or "**Code**" means the Company's Code of Conduct.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook.

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

"**Compensation Committee**" means the compensation committee of the Board.

"**Consolidation**" means the consolidation of the Common Shares on a ten to one basis completed in connection with the Business Combination.

"**Court**" means the Court of Queen's Bench of Alberta.

"**COVID-19**" means the coronavirus declared to be a global pandemic by the WHO on March 11, 2020.

"**Credit Agreement**" means the Amended and Restated Senior Secured Extendible Revolving Facility Credit Agreement dated as of September 22, 2021 among Kiwetinohk, as borrower, and a syndicate of Canadian chartered banks, as lenders.

"**Credit Facilities**" means the credit facilities available to the Company pursuant to the Credit Agreement.

"**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.

"**Deferred Plans**" means trusts governed by an RRSP, RRIF, TFSA (as such terms are defined herein), registered education savings plan, registered disability savings plan, or deferred profit sharing plan (as such terms are defined in the Tax Act), and Deferred Plan means any one of them.

"**DEP**" means the Distinction Energy Partnership.

"**Directive 067**" has the meaning ascribed thereto under the heading "*Risk Factors – Risks related to the Company – Security Deposits under Provincial Liability Management Programs – Alberta*".

"**Distinction**" means Distinction Energy Corp., a corporation which existed under the federal laws of Canada and combined with Kiwetinohk on or about September 22, 2021 pursuant to the Business Combination.

"**Distinction Board**" means the board of directors of Distinction.

"**Distinction Investments**" has the meaning ascribed thereto under the heading "*General Development of the Business – Three Year History – Recent Developments*".

"**Distinction Options**" means the options to purchase 304,436 Distinction Shares assumed by Kiwetinohk in connection with the Business Combination.

"**Distinction Shares**" means the class A common shares in the capital of Distinction.

"**Distinction Warrants**" means the purchase warrants to acquire Distinction Shares acquired by the Company in connection with the Initial Distinction Investment which upon exercise resulted in the Company holding 50% +1 of the issued and outstanding Distinction Shares.

"**Dormancy Regulation**" means the Dormancy and Shutdown Regulation, BC Reg 112/2019, as promulgated under the OGAA.

"**DRIPA**" means the *Declaration on the Rights of Indigenous Peoples Act*, SBC 2019, c 44, as amended.

"**EIA**" means the United States Energy Information Administration.

"**EOR**" means enhanced oil recovery.

"**ESG**" means environmental, social and governance.

"**ESTMA**" means the *Extractive Sector Transparency Measures Act*, S.C. 2014, c. 39, s. 376, as amended, including the regulations promulgated thereunder.

"**Federal Methane Regulations**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Climate Change Regulation – Federal*".

"FID" means Final Investment Decision.

"**Financial Statements**" means the audited and unaudited financial statements of the Company, available on the Company's profile at www.sedar.com.

"***Firm Renewable***" means a Kiwetinohk-originated term that describes efficient, flexible-output, fast-responding, gas-fired, internal reciprocating engine-driven power generation that addresses the need for stability that has been revealed as wind and solar renewable grows to become a significant proportion of a grid's power supply. See also the section entitled, "*Near to Medium Term Objectives*".

"**forward-looking statements**" has the meaning ascribed thereto under the heading "*Forward-Looking Statements and Market Data*".

"**Framework**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Climate Change Regulation – Federal*".

"**GGIRCA**" means the *Greenhouse Gas Industrial Reporting and Control Act*, SBC 2014, c 29, as amended, including the regulations promulgated thereunder.

"**GGPPA**" means the *Greenhouse Gas Pollution Pricing Act*, S.C. 2018, c. 12, s. 186, as amended, including the regulations promulgated thereunder.

"**GHG**" means greenhouse gas.

"**GLJ**" means GLJ Ltd., independent reserves evaluators.

"**Governance and Nominating Committee**" means the governance and nominating committee of the Board.

"**GUOC**" means Generating Unit Owner's Contribution.

"**GW**" means gigawatt.

"**Henry Hub**" means the Henry Hub spot price, the NYMEX natural gas trading price.

"**IAA**" means the *Impact Assessment Act*, S.C. 2019, c. 28, s. 1, as amended, including the regulations promulgated thereunder.

"**IEA**" means the International Energy Agency.

"**IFRS**" means the International Financial Reporting Standards as issued by the International Accounting Standards Board and implemented in Canada through the Accounting Recommendations in the Chartered Professional Accountants of Canada Handbook.

"**IIAC**" means the Impact Assessment Agency of Canada.

"**Initial Distinction Investment**" has the meaning ascribed thereto under the heading "*General Development of the Business – Three Year History – 2020*".

"**Investment Rights Agreement (ARC)**" has the meaning ascribed thereto under the heading "*Principal Holders of Voting Securities*".

"**Investment Rights Agreement (Luminus)**" has the meaning ascribed thereto under the heading "*Principal Holders of Voting Securities*".

"**IOGA**" means the *Indian Oil and Gas Act*, R.S.C., 1985, c. I-7, as amended, including the regulations promulgated thereunder.

"**IOGC**" means Indian Oil and Gas Canada.

"**Journey JV**" has the meaning ascribed thereto under the heading "*General Development of the Business – Three Year History – 2018*".

"**Kiskatinaw Area**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Regulatory Authorities and Environmental Regulation – British Columbia*".

"**Kiwetinohk**" or "**Company**" means Kiwetinohk Energy Corp., a corporation existing under the federal laws of Canada.

"**Lead Director**" means Beth Reimer-Heck, or such other independent lead director as may be appointed from time to time.

"**LLCM Directive**" has the meaning ascribed thereto under the heading "*Risk Factors – Risks related to the Company – Security Deposits under Provincial Liability Management Programs – Alberta*".

"**LMR**" means liability management rating.

"**LMRs**" means Liability Management Ratios.

"**LUF**" means the Government of Alberta's Land-use Framework.

"**Luminus**" means Luminus Energy IE Designated Activity Company.

"**Luminus Demand Registration**" has the meaning ascribed thereto under the heading "*Principal Holders of Voting Securities – Investment Rights Agreement (Luminus)*".

"**Luminus Piggyback Registration**" has the meaning ascribed thereto under the heading "*Principal Holders of Voting Securities – Investment Rights Agreement (Luminus)*".

"**Market Price**" means, in respect of Options only, the volume weighted average trading price of the Common Shares on the TSX, or such other exchange on which the Common Shares are listed and posted for trading and on which the majority of the trading volume and value of the Common Shares occurs, for the five trading days immediately preceding the day on which the Option is granted. In the event that the Common Shares are not traded on an exchange, then the Market Price shall be the fair market value of the Common Shares as determined by the Board in its sole discretion, acting reasonably and in good faith.

"**Maximum Offering Size**" has the meaning ascribed thereto under the heading "*Principal Holders of Voting Securities – Investment Rights Agreement (ARC)*".

"**McDaniel**" means McDaniel & Associates Consultants Ltd, independent reserves evaluators.

"**Modernized IOGA**" means An Act to amend the Indian Oil and Gas Act, S.C. 2009, c. 7, which received royal assent on May 14, 2009.

"**MSA**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Power Industry – Alberta*".

"**Named Executive Officers**" or "**NEOs**" means the named executive officers of the Company.

"**NI 45-106**" means National Instrument 45-106 - *Prospectus Exemptions of the Canadian Securities Administrators*;

"**NEB**" means the National Energy Board.

"**NEB Act**" means the *National Energy Board Act* (Canada), R.S.C. 1985, c. N-7, as amended, including the regulations promulgated thereunder.

"**NEO**" means a Named Executive Officer of the Company.

"**NGCC**" means natural gas combined cycle.

"**NGTL**" has the meaning ascribed thereto under the heading "*Description of the Business – Overview of Oil and Natural Gas Properties – Midstream, Marketing and Transportation Arrangements – TC Energy*".

"**NGX**" has the meaning ascribed thereto under the heading: "*Industry Conditions – Upstream Oil and Natural Gas Industry – Pricing and Marketing of Natural Gas, Crude Oil and NGL – Natural Gas*".

"**NIT**" has the meaning ascribed thereto under the heading: "*Industry Conditions – Upstream Oil and Natural Gas Industry – Pricing and Marketing of Natural Gas, Crude Oil and NGL – Natural Gas*".

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

"**NI 52-110**" means National Instrument 52-110 — *Audit Committees* of the Canadian Securities Administrators.

"**NI 58-101**" means National Instrument 58-101 — *Disclosure of Corporate Governance Practices* of the Canadian Securities Administrators.

"**NYMEX**" means the New York Mercantile Exchange.

"**OGAA**" means the *Oil and Gas Activities Act*, SBC 2008, c 36, as amended, including the regulations promulgated thereunder.

"**OGCA**" means the *Oil and Gas Conservation Act*, RSA 2000, c O-6, as amended, including the regulations promulgated thereunder.

"**Options**" means the stock options of Kiwetinohk, whether vested or unvested, granted or available to be granted to certain employees, directors and consultants of Kiwetinohk.

"**OPEC**" means the Organization of the Petroleum Exporting Countries.

"**Option Plan**" means the amended and restated stock option plan of the Company.

"**Order**" has the meaning ascribed thereto under the heading "*Directors and Officers – Cease Trade Orders, Bankruptcies, Penalties or Sanctions – Cease Trade Orders and Bankruptcies*".

"**Orphan Fund**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Liability Management Rating Program – Alberta*".

"**OSRF**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Liability Management Rating Program – British Columbia*".

"**Part VI Regulations**" means the National Energy Board Act Part VI (Oil and Gas) Regulation, SOR/96-244.

"**Pembina**" means Pembina Pipeline Corporation.

"**Pembina Peace Pipeline**" has the meaning ascribed thereto under the heading "*Description of the Business – Overview of Oil and Natural Gas Properties – Midstream, Marketing and Transportation Arrangements – Pembina*".

"**Performance Warrants**" means the performance warrants of Kiwetinohk, whether vested or unvested, granted or available to be granted to certain employees, directors and consultants of Kiwetinohk.

"**Person**" includes a natural person, partnership, limited partnership, limited liability partnership, corporation, limited liability company, unlimited liability company, joint stock company, trust, unincorporated organization or association, a union, joint venture or other entity or Governmental Entity, and pronouns have a similarly extended meaning.

"**Power Pool**" has the meaning ascribed thereto under the heading "*Industry Conditions – Upstream Oil and Natural Gas Industry – Alberta Electricity Market Background*".

"**PPA**" means power purchase agreement.

"**REP**" has the meaning ascribed thereto under the heading "*Industry Conditions – Power Industry – Power Generation in Alberta*".

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

"**RRIF**" means a registered retirement income fund as defined in the Tax Act.

"**RRSP**" means a registered retirement savings plan as defined in the Tax Act.

"**Seismic Protocol Regions**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Regulatory Authorities and Environmental Regulation – Alberta*".

"**Shareholder Agreement**" means the unanimous shareholder agreement governing Kiwetinohk, which terminated upon completion of the Business Combination.

"**Shareholders**" means the holders of Common Shares from time to time.

"**Simonette Acquisition**" has the meaning ascribed thereto under the heading "*General Development of the Business – Three Year History – Recent Developments*".

"**Simonette Assets**" has the meaning ascribed thereto under the heading "*General Development of the Business – Significant Acquisitions*".

"**Subsequent Distinction Investments**" has the meaning ascribed thereto under the heading "*General Development of the Business – Three Year History – Recent Developments*".

"**Sustainability Committee**" means the sustainability committee of the Board.

"**Tax Act**" means the *Income Tax Act* (Canada), R.S.C. 1985, c-1 (5th Supp.), as amended, including the regulations promulgated thereunder.

"**TFSA**" means a tax-free savings account as defined in the Tax Act.

"**TIER**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Climate Change Regulation – Alberta*".

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

"**TSX Listing Date**" means the date the Common Shares are listed and posted for trading on the TSX.

"**UN**" means the United Nations.

"**UNDRIP**" means the United Nations Declaration of Rights for Indigenous Peoples.

"**UNFCCC**" means the United Nations Framework Convention on Climate Change.

"**U.S.**" or "**United States**" means the United States of America, its territories and possessions, any state of the United States and the District of Columbia.

"**U.S. Securities Act**" means the United States Securities Act of 1933, as amended.

"**U.S. Tax Code**" means the U.S. Internal Revenue Code of 1986, as amended.

"**WHO**" means the World Health Organization.

Selected Oil and Gas Terms

In this AIF, unless otherwise indicated or the context otherwise requires, the following terms have the meaning set forth below. These definitions are generally as set forth in the COGEH, NI 51-101 and CSA 51-324 and are reproduced below for the convenience of the reader.

"**COGEH**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by The Society of Petroleum Evaluation Engineers (Calgary Chapter), as amended from time to time.

"**condensate**" means a mixture of hydrocarbons consisting primarily of pentanes and heavier liquids extracted from natural gas.

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

"**crude oil**" means, collectively, light and medium crude oil, heavy crude oil and tight oil.

"**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.

"**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 they shut in, they must have previously been on production, and on the date of resumption and production must be known with reasonable certainty.

"**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.

"**development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil, NGL and natural 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, natural gas lines and power lines, to the extent necessary in developing the reserves;

(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.

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

"**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 crude oil and natural 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.

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

"**field**" means a defined geographical area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

"**forecast prices and costs**" means future 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 a company is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in the paragraph above.

"**formation**" means a layer of rock which has distinct characteristics that differ from nearby rock.

"**gross**" means:

(a) in relation to a company's interest in production or reserves, its "company gross reserves", which are the company's working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the company;

(b) in relation to wells, the total number of wells in which a company has an interest; and

(c) in relation to properties, the total area of properties in which a company has an interest.

"**heavy crude oil**" means crude oil with a relative density greater than 10 degrees API gravity and less than or equal to 22.3 degrees API gravity.

"**light crude oil or light oil**" means crude oil with a relative density greater than 31.1 degrees API gravity. Light and medium crude oil means light crude oil and medium crude oil combined.

"**liquids**" means crude oil, condensate and other NGL.

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

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

"**net**" means:

(a) in relation to a company's interest in production or reserves, the company's working interest (operating or non-operating) share after deduction of royalty obligations, plus the company's royalty interest in production or reserves;

(b) in relation to a company's interest in wells, the number of wells obtained by aggregating the company's working interest in each of its gross wells; and

(c) in relation to a company's interest in a property, the total area in which the company has an interest multiplied by the working interest owned by the company.

"**net acres**" means the percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"**possible reserves**" are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.

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

"**producing days**" includes only days on which a well produces some quantities of natural gas or condensate.

"**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.

"**reserves**" are estimated remaining quantities of crude oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: (a) analysis of drilling, geological, geophysical and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed. Reserves are classified according to the degree of certainty associated with the estimates.

"**reservoir**" means a subsurface rock unit that contains an accumulation of petroleum.

"**resources**" means petroleum quantities that originally existed on or within the earth's crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced.

"**rich gas**" means liquids-rich natural gas.

"**shale gas**" is defined by NI 51-101 as natural gas: (a) contained in dense organic-rich rocks, including low-permeability shales, siltstones and carbonates, in which the natural gas is primarily adsorbed on the kerogen or clay minerals; and (b) that usually requires the use of hydraulic fracturing to achieve economic production rates. Kiwetinohk has also categorized what is typically referred to as "tight gas" under "shale gas" since "tight gas" is not defined in NI 51-101. This includes natural gas that is contained in low-permeability shales, siltstones and carbonates, in which the natural gas is primarily contained in microscopic pore spaces that are poorly connected to one another, which typically requires the use of hydraulic fracturing to achieve economic production rates.

"**sour gas**" means natural gas containing hydrogen sulfide (H2S) in quantities greater than 100 parts per million.

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

"**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, possible) to which they are assigned.

"**WCSB**" means Western Canadian Sedimentary Basin.

"**working interest**" or "**WI**" means the right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

The information set forth in this AIF, inclusive of the appendices hereto, relating to the Company's reserves and future net revenues, respectively, constitutes forward-looking statements which are subject to certain risks and uncertainties. See "*Forward-Looking Statements and Market Data*" and "*Risk Factors*" in this AIF.

Selected Abbreviations

In this AIF, unless otherwise indicated or the context otherwise requires, the following abbreviations shall have the meaning set forth below:

	Oil and Natural Gas Liquids
bbl	barrel
bbl/d	barrels per day
bbl/mmcf	barrels per million cubic feet
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
mbbl	thousand barrels
mmbbl	million barrels
mmbbl/d	million barrels per day
mboe	thousand barrels of oil equivalent
mmboe	millions barrels of oil equivalent
MPa	megapascal pressure unit
NPV10	net present value of future net revenues before taxes, discounted at 10% per annum
WTI	West Texas Intermediate
	Natural Gas
bcf	billion cubic feet
Btu	British thermal units
Btu/scf	British thermal units per standard cubic foot
mcf	thousand cubic feet
mcfe	thousand cubic feet equivalent
mcf/d	thousand cubic feet per day
mmBtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
	Other
API	American Petroleum Institute
H1	half year ending June 30
GJ/MWh	gigajoule per megawatt hour
GJ/d	gigajoule per day
GW	gigawatts
m	meters
MW	megawatts
MWh	megawatt hour
km	kilometers
t/mw	tonnes per megawatt
$mm	million dollars
$/bbl	dollars per barrel
$/boe	dollars per barrel equivalent
$/mcf	dollars per thousand cubic feet
$/mmBtu	dollars per million British thermal units
$/MWh	dollars per megawatt-hour
US$/bbl	U.S. dollars per barrel

Selected Conversions

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

To Convert From	To	Multiply By
Mcf	cubic metres	28.317
cubic metres	cubic feet	35.315
bbls	cubic metres	0.159
cubic metres	bbls	6.290
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
sections	acres	640
acres	sections	0.0015625

APPENDIX "B"

<u>Board Mandate</u>

KIWETINOHK ENERGY CORP.
BOARD OF DIRECTORS MANDATE

1.0 Purpose and Scope

The members of the Board oversee the conduct of the business of Kiwetinohk and the activities of management who are responsible for the day-to-day conduct of the business. In discharging its responsibility, the Board will exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances and each Director will act honestly and in good faith with a view to the best interests of the Corporation.

2.0 Definitions

"**Board**" means Kiwetinohk's board of directors.
"**CEO**" means Chief Executive Officer of the Corporation.
"**Code of Conduct**" means the Corporate Mandate and the Management Conduct policies as they may be amended from time to time, in aggregate.
"**Committee**" means any committees of the Board.
"**Director**" means an individual member of the Board.
"**Independent Director**" means a Director with no direct or indirect "material relationship" (as such term is defined in National Instrument 52-110 – Audit Committees of the Canadian Securities Administrators) with the Corporation.
"**Kiwetinohk**" or the "**Corporation**" means Kiwetinohk Energy Corp. and includes its subsidiaries where the context requires.
"Observer" means any person that the Corporation, with the approval of the Board, has agreed to allow to attend meetings of the Board.
"**Secretary**" means a Corporate Secretary, appointed by the Board (or in his or her absence a secretary who has been appointed for the purposes of a meeting).

3.0 Principles and Rules

3.1. *Composition*

The Board shall be comprised of a majority of Independent Directors. The Board shall appoint a Chair of the Board from among its members. The role of the Chair of the Board is to act as the leader of the Board, to manage and coordinate the activities of the Board and to oversee execution by the Board of this written mandate. If the Chair of the Board is not an Independent Director, a majority of the Board's Independent Directors shall appoint a Lead Director from among the Independent Directors, who will be responsible for ensuring that the Independent Directors and management have opportunities to meet without management and Directors that are not Independent Directors, as required, and will assume such other responsibilities as the Independent Directors may designate in accordance with any applicable position descriptions or other applicable guidelines that may be adopted by the Board from time to time.

The Board may, from time to time, engage consultants or members of the Corporation's management team who are not Directors including Observers and these persons may attend meetings or portions of meetings as invited guests of the Board. Otherwise, the Board will consist only of Directors and only Directors and a Corporate Secretary may attend meetings of the Board. Directors who wish to include a guest, other than a named Observer, for any portion of the meeting should arrange that inclusion with the Chair prior to the meeting.

3.2. *Operation*

The Board operates by delegating certain of its authorities to management and by reserving certain powers to itself. The Board retains the responsibility of managing its own affairs including selecting its Chair, any Lead Director, nominating candidates for election to the Board (except that any member of management who is also a shareholder shall also have the same rights of any shareholder to nominate candidates for election to the Board), constituting Committees and determining Director compensation. Subject to the articles and by-laws of the Corporation and the *Canada Business Corporations Act*, the Board may constitute, seek the advice of and delegate powers, duties and responsibilities to Committees.

The Board will hold regularly scheduled meetings as prescribed in the Board and Committee Meeting Guidelines of the Corporation, with special meetings called as necessary. The Board shall meet at the end of its regular scheduled meetings *in camera* without guests, Observers or members of management and, further without any guest, Observers, members of management or any Directors that are not Independent Directors being present. *In camera* meetings are not to be used to make decisions in which the excluded directors do not have a conflict.

The Chair of the Board presides at all meetings of the Board and shareholders. Minutes of each meeting shall be prepared by the Secretary. The CEO, if he or she is not a Director, will be available to attend all meetings of the Board or Committees upon invitation by the Board or any such Committee. The President and Vice-Presidents and such other staff as appropriate to provide information to the Board shall attend meetings at the invitation of the Board. Following each meeting, the Secretary will promptly report to the Board by way of providing draft copies of the minutes of the meetings. Supporting schedules and information reviewed by the Board at any meeting shall be available for examination by any Director upon request to the CEO.

3.3. *Responsibilities*

The Board is responsible under law to supervise the management of the business and affairs of the Corporation. In broad terms, the stewardship of the Corporation involves the Board in strategic planning, risk identification, management and mitigation, senior management determination, succession planning, communication planning and internal control integrity.

3.3.1. *Specific Duties*

Without limiting the foregoing, the Board shall have the following specific duties and responsibilities:

(a) ***Fostering Corporate Culture***

The Board has the responsibility to:

(i) Direct or aid management to define those characteristics of performance and behavior which contribute to the desired Corporate Culture.

(ii) Establish performance measures and assess the performance of the Corporation in the service of its stakeholders as defined in the Code of Conduct.

(iii) Support measures to train senior management to demonstrably live in accordance with the Code of Conduct.

(iv) Measure the CEO and senior management as to exemplary leadership in performing in accordance with the Code of Conduct seeking excellence set by "tone at the top."

(b) ***Strategy Determination***

The Board has the responsibility to:

(i) adopt a strategic planning process for the Corporation and to participate with management directly or through its Committees in approving goals and the strategic plan (on at least an annual basis) for the Corporation by which the Corporation proposes to achieve its goals and take into account the opportunities and risks of the business;

(ii) develop and approve the corporate goals and objectives the CEO is responsible for meeting;

(iii) monitor the implementation and execution of the tasks constituent to the corporate strategy;

(iv) monitor the appropriateness of the Corporation's capital structure, including:

(A) approving the borrowing of funds and the establishment of credit facilities;

(B) approving issuances of additional shares or other securities of the Corporation, including securities convertible into shares, to the public or otherwise and any offering documents, such as prospectuses; and

(C) establish limits of authority delegated to management.

(c) ***Managing Risk***

The Board has responsibility for the oversight of management's identification and evaluation of the Corporation's principal risks, including (without limitation) environment, climate-related and social risks, and the implementation of policies, processes and systems to manage or mitigate the risks to achieve an appropriate balance between the risks incurred and potential benefits to the Corporation's stakeholders.

(d) ***Appointment, Training Monitoring and, if deemed prudent, dismissing Senior Management***

The Board has the responsibility:

(i) to appoint the CEO and establish a position description of the CEO's responsibilities and other senior management's responsibilities, to monitor and assess the CEO's performance, to determine the CEO's compensation and to provide advice and counsel in the execution of the CEO's duties;

(ii) to approve the appointment and remuneration of the Corporation's senior management;

(iii) to establish provisions for the training and development of management and for the orderly succession of management;

(iv) terminate the CEO if the Board deems the CEO to be less than fit for duty other temporary absence due to illness or compassionate leave; and

(v) direct the termination of any employee.

(e) ***Reporting and Communication***

(i) to ensure compliance with the reporting obligations of the Corporation, including that the financial performance of the Corporation is properly reported to stakeholders, including shareholders, other security holders and regulators on a timely and regular basis;

(ii) to recommend to shareholders of the Corporation a firm of certified professional accountants to be appointed as the Corporation's auditors;

(iii) to ensure that the financial results of the Corporation are reported fairly and in accordance with generally accepted accounting principles;

(iv) to ensure the timely reporting of any change in the business, operations or capital of the Corporation that would reasonably be expected to have a significant effect on the market price or value of the securities of the Corporation;

(v) to ensure the independent oil and gas reserves report of the Corporation is prepared in accordance with generally accepted engineering principles and applicable securities laws;

(vi) to review the Corporation's approach to sustainability reporting, including the manner in which stakeholder concerns with respect to the environment, climate change, social issues and governance are addressed;

(vii) to establish a process for direct communications with shareholders and other stakeholders through appropriate Directors and/or Independent Directors, including through the Whistleblower Policy;

(viii) to review and respond to potential conflict of interest situations and Code of Conduct conflict situations;

(ix) to ensure that the Corporation has in place a policy to enable the Corporation to communicate effectively with its shareholders and the public generally; and

(x) to report annually to shareholders on its stewardship of the affairs of the Corporation for the preceding year.

(f) ***Monitoring and Acting***

(i) to establish policies and processes for the Corporation to operate at all times within applicable laws and regulations to the highest ethical and moral standards (advancing the interests of the Corporation, including the pursuit of differentiating performance in meeting the reasonable needs of all stakeholders of the Corporation);

(ii) satisfy itself on to the integrity of the CEO and management and that such individuals create a culture of integrity throughout the Corporation;

(iii) to ensure that management has and implements procedures to comply with, and to monitor compliance with, significant policies and procedures by which the Corporation is operated;

(iv) to promote, and to ensure that management promotes, high environmental standards in the Corporation's operations at least in compliance with environmental laws and regulations;

(v) to ensure that management establishes appropriate programs and policies for the health and safety of the Corporation's employees in the workplace;

(vi) to monitor the Corporation's progress towards its goals and objectives and to revise and alter its direction through management in response to changing circumstances;

(vii) to take action when performance falls short of its goals and objectives or when other special circumstances warrant or when changing circumstances in the business environment create risks or opportunities for the Corporation;

(viii) to approve annual (or more frequent as the Board feels to be prudent from time to time) operating and capital budgets and review and consider amendments or departures proposed by management from established strategy, capital and operating budgets or matters of policy which diverge from the ordinary course of business that may significantly impact the value of or opportunities available to the Corporation; and

(ix) to implement internal control and information systems and to monitor the effectiveness of same.

(g) *Governance*

(i) to develop the Corporation's approach to corporate governance including (without limitation) developing a set of corporate governance principles and guidelines;

(ii) to develop a position description for the Chair of the Board, any Lead Director, the Chair of each Committee and the CEO;

(iii) to facilitate the continuity, effectiveness and independence of the Board by, among other things:

(A) appointing from amongst the Directors an Audit Committee, a Governance and Nominating Committee, a Compensation Committee, a Reserves Committee and a Sustainability Committee and such other Committees as the Board deems appropriate;

(B) defining the mandate, including both responsibilities and delegated authorities, of each Committee;

(C) establishing a system to enable any Director to engage an outside adviser at the expense of the Corporation;

(D) ensuring that processes are in place and are utilized to assess the effectiveness of the Chair of the Board, any Lead Director, the Board as a whole, each Director, each Committee and each Committee's Chair;

(E) reviewing annually the composition of the Board and its Committees and assessing Directors' performance on an annual basis, and appointing new members to the Board; and

(F) reviewing the adequacy and form of the compensation of the Directors;

(iv) to provide a comprehensive orientation to each new Director.

4.0 Other Matters

The Board may perform any other activities consistent with this Mandate, the Corporation's articles and by laws and any governing laws as the Board deems necessary or appropriate.

5.0 Related Policies and Mandates

- Position Description for Chair of the Board
- Position Description for Chief Executive Officer
- Governance and Nominating Committee Mandate
- Position Description for Governance and Nominating Committee Chair
- Audit Committee Mandate
- Position Description for Audit Committee Chair
- Sustainability Committee Mandate
- Position Description for Sustainability Committee Chair
- Compensation Committee Mandate
- Position Description for Compensation Committee Chair
- Reserves Committee Mandate
- Position Description for Reserves Committee Chair
- Code of Conduct
- Whistleblower Policy
- Disclosure Policy
- Board and Committee Meeting Guidelines

6.0 Review and Modification

This Mandate shall be reviewed by the Governance and Nominating Committee of the Board on an annual basis and any Director may make recommendations for changes to the Governance and Nominating Committee and the Governance and Nominating Committee will provide recommended changes or modifications (if any) to this Mandate to the Board for consideration and, at the Board's discretion, approval.

APPENDIX "C"

Audit Committee Mandate

KIWETINOHK ENERGY CORP.
AUDIT COMMITTEE MANDATE

1.0 Purpose and Scope

The Committee is a committee of the Board whose primary function is to assist the Board by:

- overseeing the nature and scope of the Corporation's annual independent audit and the integrity of the Corporation's financial statements;
- overseeing the Corporation's external independent auditor's performance, qualifications and independence;
- overseeing management's implementation and maintenance of an effective system of internal controls over cash management and financial reporting;
- overseeing the Corporation's legal and regulatory compliance requirements with respect to financial management and reporting;
- overseeing the Corporation's financial risk management programs including insurance, cash management, hedging, marketing and debt;
- overseeing the Corporation's systems of financial disclosure control and procedures; and
- recommending, for Board approval, the audited financial statements and other mandatory disclosure releases containing financial information.

2.0 Definitions

"**Board**" means Kiwetinohk's board of directors.
"**Committee**" means the Audit Committee of the Board.
"**Code of Conduct**" means the Corporate Mandate and all of the policies governing management conduct, considered in aggregate.
"**CPAB**" means the Canadian Public Accountability Board.
"**Independent**" and "**Financially Literate**" mean as described in NI 52-110.
"**Kiwetinohk**" or the "**Corporation**" means Kiwetinohk Energy Corp. and includes its subsidiaries where the context requires.
"**MD&A**" means Management Discussion and Analysis document.
"**NI 52-110**" means National Instrument 52-110 – Audit Committees.

3.0 Principles and Rules

3.1. *Composition and Meetings*

- The Committee must be comprised of a minimum of three Independent and Financially Literate directors of the Board, unless the Board determines that an exemption contained in NI 52-110 is available and determines to rely thereon in respect of any such individual, and free of any relationship that, in the opinion of the Board, would interfere with the exercise of his or her independent judgment as a member of the Committee. In particular, at least one member of the Committee shall have experience as a certified public accountant, chief financial officer or corporate controller of similar experience, or demonstrably meaningful experience overseeing such functions as a senior executive officer.

- In order to foster open communication, the Committee or its Chair should meet at least annually with management and the external independent auditor in separate sessions to discuss any matters that the Committee or each of these groups believes should be discussed privately. In addition, the Committee or its Chair should meet with management quarterly in connection with the Corporation's interim financial statements and the Committee should meet not less than quarterly with the external independent auditor, independent of the presence of management.

- The Committee will meet as scheduled and in the manner prescribed in the Board and Committee Meeting Guidelines of the Corporation.

3.2. *Role*

In addition to any other duties and authorities delegated to it by the Board from time to time, the role of the Committee is to:

3.2.1. *Financial Statements*

(a) Review significant accounting and reporting issues, including complex, unusual transactions or non-recurring transactions, highly judgemental areas, related party transactions and recent professional and regulatory pronouncements and understand their impact on the financial statements.

(b) Review with management and the external independent auditor the results of any audit and any adjustments or difficulties encountered including (without limitation) unresolved differences.

(c) Review the annual / interim financial statements and consider whether they are complete, consistent with the information known to Committee members and reflect appropriate and current accounting principles.

(d) Review analyses prepared by management and the external independent auditor setting forth significant financial reporting issues and judgements made in connection with the preparation of financial statements including alternative treatments and their impacts.

(e) Review all financing reporting relating to risk exposure including the identification, monitoring and mitigation of business risks and disclosure related thereto.

(f) Increase the credibility and objectivity of the financial statements and financial reports.

(g) Recommend to the Board the approval of the Corporation's financial statements.

3.2.2. *Internal Controls*

Satisfy itself on behalf of the Board with respect to the internal control systems, including, but not exclusively:

(a) matters relating to financial risk management, including the Corporation's market risk management policies and practices and the use of derivative instruments;

(b) management's identification, monitoring and development of strategies to avoid and/or mitigate accounting and finance risks;

(c) the adequacy of the security measures that are in place in respect of the Corporation's information systems and the information technology that is utilized by the Corporation;

(d) establishing procedures for the anonymous and confidential receipt, retention and treatment of complaints regarding accounting, internal accounting controls or auditing matters and the confidential and anonymous submission by employees of the Corporation of concerns regarding questionable financial management, accounting or auditing matters under the Whistleblower Policy;

(e) satisfy itself that adequate procedures are in place for the review of the Corporation's public disclosure of financial information extracted or derived from the Corporation's financial statements and periodically assess the adequacy of these procedures; and

(f) monitoring compliance with legal and regulatory requirements, including:

i. reviewing management's process for certification of annual and interim financial reports in accordance with National Instrument 52-109 - *Certification of Disclosure in Issuers' Annual and Interim Filings*;

ii. compliance with covenants under credit facility loan agreements;

iii. any examinations or reports by regulatory agencies;

iv. any external independent auditor observations; and

v. regular updates from management and legal counsel regarding compliance matters.

3.2.3. *Documents/Reports Review*

(a) Review and recommend to the Board for approval the Corporation's annual financial statements, forms, filings and circulars containing financial information, including the Extractive Sector Transparency Measures Act (Canada) filing and management's process for certification under that legislation.

(b) Review and approve the Corporation's quarterly financial statements and MD&A, as well as any insurance, hedging, marketing, cash management or other report, including any certification or opinion rendered by the external independent auditor.

3.2.4. *External Independent Auditor*

(a) Review the external independent auditor's proposed scope and approach.

(b) Recommend to the Board the external independent auditor to be nominated for appointment by the shareholders for the purpose of preparing or issuing an auditor's report or performing other audit, review or other services for the Corporation and the compensation of the external independent auditor.

(c) Direct the compensation and retention of, and oversee the work performed by the external independent auditor, and at least every five years, conduct a comprehensive review of the external independent auditor.

(d) Review and approve all audit and non-audit services to be provided by the external independent auditor. Provide oversight to ensure that the provision of non-audit services is within regulations and best practices.

(e) Actively engage in dialogue with the external independent auditor with respect to any disclosed relationships or services that may affect the independence and objectivity of the external auditor and take appropriate actions to oversee the independence of the external auditor and at least annually obtain a formal written statement delineating all relationships between the external independent auditor and the Corporation.

(f) Review and confirm the independence of the external independent auditor.

(g) Review the performance of the external independent auditor.

(h) Periodically consult with the external independent auditor without the presence of management to discuss any matters that the Committee or the external independent auditor believe should be discussed privately.

(i) Review with external independent auditor (and any internal auditor if one is appointed by the Corporation) their assessment of the internal controls of the Corporation, their written reports containing recommendations for improvement, and management's response and follow-up to any identified weaknesses.

(j) Review and approve any hiring decisions regarding partners, employees and former partners and employees of the external independent auditor.

(k) Review the Annual Report of the CPAB concerning audit quality in Canada and discuss implications for the Corporation.

(l) Review any report by CPAB regarding the audit of the Corporation.

(m) Review with the external independent auditor and management significant findings during the year and the extent to which changes or improvements in financial or accounting practices, as approved by the Committee, have been implemented.

(n) Resolve any disagreements between management and the external independent auditor.

(o) When there is to be a change in the external independent auditor, review the issues related to the change and the information to be included in the required notice to securities regulators of such change.

3.3. *Other Authorities*

- The Committee is empowered to seek any information it requires from employees, all of whom are directed to cooperate with the requests of the Committee or its agents.

- Perform any other activities as the Committee deems necessary or appropriate.

4.0 Other Matters

N/A.

5.0 Related Policies and Mandates

Code of Conduct

Whistleblower Policy

Board and Committee Meeting Guidelines

6.0 Review and Modification

The Committee will review at least annually and recommend to the Governance and Nominating Committee of the Board changes or modifications (if any) to this Mandate, as considered appropriate, from time to time. The Governance and Nominating Committee of the Board will review this mandate annually, at minimum and make recommendations of its own origin and with regard to changes proposed by the Committee (if any) to the Board.

APPENDIX "D"

Statement of Executive Compensation

Compensation Discussion and Analysis

Compensation Philosophy

Kiwetinohk acknowledges that social licence to operate is critical to an expectation of shareholder value performance over the long term. The Board looks to the CEO to advance Kiwetinohk's business in accordance with the Code of Conduct. The Code of Conduct prescribes the expectations Kiwetinohk has of those in its service with respect to communicating with and satisfying stakeholders. Kiwetinohk's directors, who have a duty in law to serve the best interests of Kiwetinohk, believe that differentiated (relative to peers) performance for investors is most probable if Kiwetinohk also differentiates in the service of groups of people who have the capacity to aid or impair Kiwetinohk in its pursuit of its business objectives. Kiwetinohk refers to these groups of people as stakeholders. Among Kiwetinohk's stakeholders are:

(a) the environment and those who have taken on a duty to protect it;

(b) governments and regulators who, faced with the challenges presented by climate change seek to evolve regulation so that the energy industry can better serve society;

(c) all communities most impacted by Kiwetinohk's activities;

(d) industry partners who expect Kiwetinohk to honor its arrangements and reasonably accommodate change and adaptation;

(e) customers who want Kiwetinohk to reliably deliver its products at the specifications and in the amounts that it forecasts;

(f) suppliers and service providers who want an opportunity to compete for Kiwetinohk's business, to be paid promptly and fairly and to learn marketable skills as they contribute to the evolution of Kiwetinohk's business;

(g) employees who want an energizing, inclusive, happy work environment where everyone is treated with dignity and respect, to be compensated fairly and to have a safe and healthy workplace; and

(h) capital providers who want strong returns on their investment, effective communication and management of risks: financial, environmental and reputational.

The role of the CEO is to lead the employees in developing and implementing a balance of practices and policies which the needs of all our stakeholders. In measuring the CEO's performance, the Board looks to gauge Kiwetinohk's relationships with its stakeholders.

The CEO leads the management team in identifying and assessing alternative business strategies. These assessments guide the Board to adoption and revision of strategies that are designed to differentiate Kiwetinohk in the eyes of its stakeholders, as demanded by the Code of Conduct. The CEO oversees the management team to implement strategies. Key performance indicators include measurement of performance by gauges most important to each stakeholder. For example, shareholders want to see cash returns and/or share price growth and strong performance in the factors underlying shareholder value (including reserves volumes and value, production rate, unit operating costs and capital investment performance metrics). Communities want to know what is going on in their area, to contribute to strategies and plans and to participate in operations as employees or contractors. Individuals tasked with environmental protection, non-governmental environmental organizations and the broader community want, to varying degrees, to see conservation of natural habitat, protection of the land, water and atmosphere from releases of pollutants including GHGs, and restoration of lands when Kiwetinohk is no longer using them for value generation. Governments and regulators want Kiwetinohk to comply with all laws and regulations, to build good relationships with its other stakeholders and to help them understand, in the rapidly evolving energy transition world, how they, also, can better serve society.

Within the foregoing context, the purposes of Kiwetinohk's compensation policy are: (a) to attract and retain individuals that have the training, experience, required certifications and track records of excellent performance to serve as executive officers and employees of Kiwetinohk; (b) to motivate and/or reward performance in proportion to level of achievement; and (c) to align the interests of executive officers and employees of Kiwetinohk with the long-term interest of shareholders. As Kiwetinohk has evolved into a more widely held company as a result of the completion of the April 2021 equity financing and the Business Combination, the Company has reviewed compensation for all executive officers against a comparator group of similarly sized crude oil and natural gas and power generation companies, considered in the context of Kiwetinohk's performance relative to performance goals and relative to the performance of its peers.

Kiwetinohk's executive compensation philosophy reflects the following principles:

(a) Compensation levels should be competitive — A competitive compensation program is vital to Kiwetinohk's ability to attract and retain executive officers and employees that can do all that is required to position Kiwetinohk among the leaders of its peer group.

(b) Compensation should be related to performance — A significant portion of the compensation of the executive officers should be based on corporate and individual performance. During periods when performance meets or exceeds expectations, executive officers should receive compensation at levels that are above market. When performance is below expectations, incentive award payments, if any, and compensation generally should be lower.

(c) Compensation at risk should represent a significant percentage of an executive officer's total compensation — A significant percentage of compensation should be paid in the form of short-term and long-term incentives, calculated and paid based on performance for Kiwetinohk's stakeholders. Executive officers' incentives must be aligned with stakeholder satisfaction with special consideration to shareholder value realization.

(d) Incentive compensation should balance short-term and long-term performance — Executive officers receive both short-term and long-term incentives. Short-term incentives focus on achievements for the current year, while equity-based compensation creates a focus on increasing long-term shareholder value.

Oversight of Executive Compensation

The Compensation Committee oversees the compensation of the NEOs. See "*Compensation Discussion and Analysis – Named Executive Officers*" in this Appendix "D" for a list of Kiwetinohk's NEOs for 2020. The Compensation Committee consists of the following independent directors: Leland Corbett; Nancy Lever; Steve Sinclair; and Kaush Rakhit. Each of the Compensation Committee members has served as a senior officer and/or as a director of numerous organizations or has direct experience in executive and corporate compensation programs, and therefore has the necessary background and skills to provide effective oversight of executive and director compensation and ensure that sound risk management principles are being adhered to in order to align executive officers' and shareholders' interests. See "*Directors and Officers*" in the AIF for the biographies of each of the Compensation Committee members.

The Compensation Committee monitors the compensation practices of Kiwetinohk to ensure that its compensation practices allow Kiwetinohk to attract and retain high performing executive officers and employees. The Compensation Committee can engage the services of consulting compensation experts.

Historically, until the final draw of optional investment funds in conjunction with the Simonette Acquisition, Kiwetinohk was in its start-up phase, investing the initial optional investment amount allocated to ARC - its majority Shareholder - in accordance with the original financing agreements. During this period, Kiwetinohk was not expected to fund its activities from a combination of cash flow, debt and equity capital raises from investment outside of the original financing agreement. During this phase of the business, the CEO was compensated as follows:

(a) $1.00 per year salary;

(b) participation in Kiwetinohk's benefit plan;

(c) Options to buy Common Shares at $10.00 per Common Share, which was the issue price of all of the funds invested in accordance with the initial financing of Kiwetinohk;

(d) Performance Warrants to buy Common Shares which have strike prices of $15.00, $17.50, $20.00, $22.50 and $25.00 (20% of the total amount of Performance Warrants in each grant vest at each of the referenced prices); and

(e) performance of his own investment (Mr. and Mrs. Carlson, who is also a part time Kiwetinohk employee, have each invested $5,000,000 in accordance with the initial ARC optional financing).

In offering and reviewing compensation for other employees, historically, the Compensation Committee has relied on various external sources of information, including industry compensation surveys which provide market data on executive officer and non-executive officer compensation. The Compensation Committee took into account survey information and other factors in determining executive officer and non-executive officer base salaries for 2020. No bonuses or salary increases were awarded to the NEOs in 2020. Kiwetinohk rewarded its employees and some of the full-time consulting staff by purchasing for them 100 Distinction special warrants in early 2021 and providing an additional $1,000 dollars to partially or fully cover the income tax burden imposed by the warrant gift.

The Compensation Committee reviews, on an annual basis, compensation of each executive officer. In each case, the Compensation Committee takes into account the scope of responsibilities, experience and contribution and performance of the executive officer, as well as the achievements of Kiwetinohk, and balances these against competitive compensation levels considering peer data.

In connection with this annual review by the Compensation Committee, the CEO presents to the Compensation Committee management's evaluation of Kiwetinohk's performance relative to its peer group, his evaluation of each executive officer, which includes a review of each executive officer's contribution and performance over the past year, strengths, weaknesses, development plans and succession potential. The Compensation Committee members also have the opportunity to interface with the executive officers during the year.

Comparator Group

Until recently, Kiwetinohk was a tightly held private company. As such, Kiwetinohk awarded compensation to its executive officers and other employees in a manner consistent with the foregoing principles and in reliance on industry compensation surveys and other external data, but without a rigorous comparison to the specific compensation practices of its publicly traded peers. Following completion of the Business Combination, Kiwetinohk is reviewing its compensation practices to ensure they align with public company best practices and has engaged a compensation consultant. The Company anticipates working closely with its compensation consultant over the following months with a view to establishing compensation practices aligned with public company best practices including developing an appropriate peer comparator group.

Pay Positioning

Kiwetinohk generally positions pay competitive to the median of a broad comparator group as defined in industry compensation surveys when performance is median, among the upper third of the comparator group when performance is among the highest third and among the lower third of the comparator group when performance is among the lower third. More generally, pay can be well above median when performance is exceptional and is expected to be below median when performance is below expectations.

Named Executive Officers

As of the date hereof, the Company's NEOs are:

(a) Patrick Carlson, CEO;

(b) Jakub Brogowski, CFO;

(c) Sue Kuethe, Executive Vice President, Land and Community Inclusion;

(d) Kurt Molnar, Senior Vice President, Business Development; and

(e) Mike Hantzsch, Senior Vice President, Midstream and Market Development.

On September 15, 2021, the Company hired Janet Annesley as Chief Sustainability Officer. On November 11, 2021, the Company hired Mike Backus as Chief Operating Officer (Upstream Division). Ms. Annesley and Mr. Backus would be NEOs in 2021 if they had been employed by the Company for the entire year. It is expected that Ms. Annesley and Mr. Backus will be NEOs in 2022.

Compensation Components

The components of Kiwetinohk's executive officer compensation program are base salary, annual incentive, long-term incentive and benefits each as described below. The components of compensation Kiwetinohk will use to recruit and maintain a workforce include:

(a) cash compensation including salary and bonuses;

(b) share-based compensation;

(c) health and life insurance; and

(d) lifestyle support.

Aside from the above, Kiwetinohk expects its culture, standards and reputation will also provide a basis for employer competitiveness.

Cash Compensation

As to cash compensation, Kiwetinohk targets salary at about the industry median for people with the skill set required. Bonuses will be used to top up total cash compensation to provide a high total cash income for strong performance of the individual and the Company, median total cash income for median performance of the individual and the Company and weak total cash income for weak performance of the individual and the Company.

Long-Term Incentives

Kiwetinohk's current long-term incentives include a mix of Options and Performance Warrants both of which are designed to strengthen the alignment between compensation and the long-term interests of shareholders.

The grant of share-based compensation is determined by the Board on the recommendation of the Compensation Committee, in accordance with the terms of the applicable incentive plan or certificate. Awards are designed to provide shareholder aligned incentives to Kiwetinohk's directors, officers, employees and consultants who make material contributions to the successful operation of the business of Kiwetinohk, to increase their ownership interest in Kiwetinohk and to allow Kiwetinohk to attract and retain outstanding talent. The long-term incentives are administered by the Board (or the Compensation Committee), which, from time to time, recommends to the Board grants to eligible persons after considering their present and potential contributions and other relevant factors.

Options are exercisable (unless otherwise determined by the Board) for Common Shares, and vest 1/3 per year on each of the first three anniversaries of the date of grant. Options have a term of seven years.

In addition to Options, ARC and management agreed at the inception of Kiwetinohk to allocate a pool of Performance Warrants as a gain-sharing arrangement that is commonly used in private companies financed by private equity funds. Performance Warrants are similar in structure to Options, but have escalating strike prices that ensure the employees only begin to share in the appreciation in the Common Share price at substantially higher share prices than that which prevailed at the time of grant. Like Options, Performance Warrants generally vest 1/3 per year over three years. Performance Warrants have a term of seven years. Following June 28, 2021 (being the date of the Business Combination Agreement), any additional Performance Warrants granted will have a term of five years, Performance Warrants may be exercised at or before the expiry of their term, a "liquidity event" (as defined in the applicable Performance Warrant certificate) or upon the completion of a "change of control" (as defined in the applicable Performance Warrant certificate). The termination of Performance Warrants as a result of a liquidity event or a change of control would require an affirmative vote of the Board, as well as a period of time within which the holders of Performance Warrants would have the opportunity to exercise those instruments.

Actual long-term incentive awards of Options and Performance Warrants have varied based on corporate and individual performance, market conditions, stock price and availability of awards for grant. To date, awards have been determined on an *ad hoc* basis, generally tied to the achievement of operational milestones.

Previous awards and grants of long-term incentive awards of Options and Performance Warrants, whether vested or unvested, have no impact on the current year's awards and grants.

Options have no value unless the Market Price of the Option increases above the exercise price of the Option. This links a portion of executive compensation directly to shareholders' interests by providing an incentive to increase the value of the Common Shares. Performance Warrants have an escalating exercise price, further aligning the interests of executive officers with the interests of Shareholders.

Pension, Benefits and Perquisites

Kiwetinohk does not currently have a pension plan or post-employment compensation and benefits in place for any of its employees.

The Compensation Committee annually reviews the benefits provided to executive officers, which are generally the same as those provided to other employees of Kiwetinohk, to determine if adjustments are appropriate. The executive officers receive minimal perquisites in each case with an aggregate value of less than $10,000 per executive officer per year and which includes paid parking for Calgary-based officers.

Compensation Mix

Employees have been granted Options and Performance Warrants, neither of which has any material cash value. The value of such Options and Performance Warrants following completion of any listing of the Common Shares will depend on the trading price of the Common Shares.

Changes for 2021 and 2022

In early 2021, the Company introduced a salary rollback due to market conditions. This reduction was implemented in two stages on a 0-15% sliding scale, depending on the employee's salary. This rollback was reversed effective November 1, 2021 in response to more competitive market conditions that emerged throughout the year. In addition, Kiwetinohk issued additional Options and Performance Warrants to employees, including NEOs, in 2021. See "*Prior Sales*" and "*Capital Structure*" in the AIF.

The Company also intends to engage an expert compensation consultant to advise the Compensation Committee and the Board with respect to competitive compensation strategies. The Company anticipates working closely with this compensation consultant over the following months with a view to establishing compensation practices aligned with public company best practices including developing an appropriate peer comparator group. In particular, the Company expects to revise the cash compensation payable to its Chief Executive Officer from its current level of $1 annually to a level that is commensurate with the Company's peers.

2020 Compensation Details

The following table sets out the compensation earned by the NEOs for the most recent three years. Annual incentives have historically been considered from time to time. This compensation period has aligned with Kiwetinohk's historical reserve reporting period and allowed compensation decisions to benefit from the completion of the busy winter drilling season. The annual incentives reported below have been included in the summary compensation table for the year in which they were paid.

					Non-equity incentive plan compensation ($)				
Name and Principal Position	**Year**	**Salary ($)**	**Share-based Awards ($)**	**Option/ Warrant-based Awards ($)[1]**	**Annual Incentive Plans**	**Long-term Incentive Plans**	**Pension Value ($)**	**All other Compen-sation ($)**	**Total Compen-sation ($)**
Patrick Carlson	2020	1	--	-	--	--	--	6,600	6,601
CEO	2019	1	--	-	--	--	--	6,600	6,601
	2018	1	--	3,777,343	--	--	--	6,600	3,783,944
Jakub Brogowski	2020	250,000	--	-	--	--	--	6,600	256,600
CFO	2019	250,000	--	-	--	--	--	6,600	256,600
	2018	250,000	--	664,533	--	--	--	6,600	921,133
Sue Kuethe	2020	235,000	--	-	--	--	--	6,600	241,600
EVP, Land and Community	2019	235,000	--	-	--	--	--	6,600	241,600
Inclusion	2018	235,000	--	642,148	--	--	--	6,600	619,209
Kurt Molnar	2020	154,362	222,980	--	--	--	--	6,600	383,942
SVP, Business	2019	26,325	--	591,784	--	--	--	1,100	619,209
Development	2018	--	--	--	--	--	--	-	-
Mike Hantzsch	2020	250,000	--	--	--	--	--	6,600	256,600
SVP, Midstream and	2019	250,000	--	--	--	--	--	6,600	256,600
Market Development	2018	250,000	--	683,419	--	--	--	6,600	940,019

Note:

(1) The grant date fair value of the Option/Warrant-based awards are calculated using the Black-Scholes option pricing model on the date of grants which is consistent with the fair value determined in accordance with IFRS 2 Share-based Payment. Options granted in 2020, 2019 and 2018 were valued at N/A, $5.30 and $5.30 per Option, respectively. The Performance Warrants were valued at N/A, $3.60 and $3.60 per Performance Warrant for grants in 2020, 2019 and 2018, respectively. The Capital Warrants were not valued as they were terminated without being exercised upon completion of the Business Combination. The key assumptions and estimations for this model include the current market price of the Common Shares, the exercise price of the Option/Warrant, the expected Option/Warrant term, the risk-free interest rate, the expected annual dividend per Common Share, the volatility of the price of the Common Shares and the estimated hold period prior to exercise. The actual value realized pursuant to such Option/Warrant-based awards may be greater or less than the indicated value. The assumptions used to calculate the fair value of the Options/Warrants using the Black-Scholes model for 2020, 2019 and 2018 Option and Performance Warrant and Capital Warrant grants are as follows:

Assumptions	Options			Performance Warrants			Capital Warrants		
	2020	2019	2018	2020	2019	2018	2020	2019	2018
Exercise price (weighted average $ per Option/ Performance Warrant/Capital Warrant)	N/A	$10.00	$10.00	N/A	$20.00	$20.00	N/A	N/A	N/A
Risk-free interest rate (%)	N/A	2.36	2.36	N/A	2.36	2.36	N/A	N/A	N/A
Expected annual dividend per Common Share (%)	N/A	–	–	N/A	–	–	N/A	N/A	N/A
Volatility of the Common Shares (%)	N/A	50	50	N/A	50	50	N/A	N/A	N/A
Estimated hold period prior to exercise (years)	N/A	7	7	N/A	7	7	N/A	N/A	N/A

Incentive Plan Awards

Outstanding Share-Based Awards and Option-Based Awards

The following tables set forth all awards outstanding for each NEO as of December 31, 2020, including awards granted before December 31, 2020.

	Option-Based Awards				Share-Based Awards		
Name	Number of Common Shares Underlying Unexercised Options (#)(1)	Options Exercise Price ($)	Option Expiration Date	Value of Unexercised in-the-money Options ($)(2)	Number of Shares or Units of Shares that have not Vested (#)	Market or Payout Value of Share-Based Awards that have not Vested ($)	Market or Payout Value of Vested Share-Based Awards not Paid out or Distributed ($)
Patrick Carlson	300,000	10.00	October 3, 2025	--	--	--	--
Jakub Brogowski	52,777	10.00	October 3, 2025	--	--	--	--
Sue Kuethe	51,000	10.00	October 3, 2025	--	--	--	--
Kurt Molnar	47,000	10.00	October 3, 2025	--	--	--	--
Mike Hantzsch	54,277	10.00	October 3, 2025	--	--	--	--

Notes:

(1) Since December 31, 2020, an additional 187,998 Options have been issued to Mr. Carlson, an additional 56,536 Options have been issued to Mr. Brogowski, an additional 53,110 Options have been issued to Ms. Kuethe, an additional 48,622 Options have been issued to Mr. Molnar and an additional 46,451 Options have been issued to Mr. Hantzsch.

(2) Based on the last equity price at which Common Shares were issued on April 23, 2021 of $10.00 per Common Share.

	Performance Warrant-Based Awards			
Name	Number of Common Shares Underlying Unexercised Warrants (#)(1)	Warrant Exercise Price ($)(2)(3)	Warrant Expiration Date	Value of Unexercised in-the-money Warrants ($)(4)
Patrick Carlson	600,000	20.00	October 3, 2025	--
Jakub Brogowski	105,556	20.00	October 3, 2025	--
Sue Kuethe	102,000	20.00	October 3, 2025	--
Kurt Molnar	94,000	20.00	October 3, 2025	--
Mike Hantzsch	108,555	20.00	October 3, 2025	--

Notes:

(1) Since December 31, 2020, an additional 742,000 Performance Warrants have been issued to Mr. Carlson, an additional 262,414 Performance Warrants have been issued to Mr. Brogowski, an additional 244,870 Performance Warrants have been issued to Ms. Kuethe, an additional 230,870 Performance Warrants have been issued to Mr. Molnar and an additional 217,704 Performance Warrants have been issued to Mr. Hantzsch.

(2) Reflects exercise price per Common Share.

(3) The Performance Warrants have exercise prices in tranches ranging from $15.00 to $25.00 per Common Share, with a weighted average exercise price of $20.00 per Common Share.

(4) Based on the last equity price at which Common Shares were issued on April 23, 2021 of $10.00 per Common Share.

	Capital Warrant-Based Awards(3)			
Name	Number of Common Shares Underlying Unexercised Warrants (#)	Warrant Exercise Price ($)(1)	Warrant Expiration Date	Value of Unexercised in-the-money Warrants ($)(2)
Patrick Carlson	1,300,000	$10.00+	August 20, 2025	--
Jakub Brogowski	13,000	$10.00+	August 20, 2025	--
Sue Kuethe	26,000	$10.00+	August 20, 2025	--
Kurt Molnar	--	--	August 20, 2025	--
Mike Hantzsch	45,500	$10.00+	August 20, 2025	--

Notes:

(1) The exercise price of Capital Warrants was $10.00 plus 2/3 of the excess of a liquidity or initial public offering price per Common Share above $15.00.

(2) Based on the last equity price at which Common Shares were issued on April 23, 2021 of $10.00 per Common Share.

(3) All Capital Warrants were cancelled upon completion of the Business Combination and no Capital Warrants remain outstanding.

Incentive Plan Awards — Value Vested or Earned During the Year

The following table sets forth incentive plan awards for each NEO for value vested or earned during the year ended December 31, 2020.

Name	Option -Based Awards —Value Vested During the Year ($)	Warrant-Based Awards — Value Vested During the Year ($)	Share-Based Awards Value Vested During the Year ($)	Non-Equity Incentive Plan Compensation — Value Earned During the Year ($)
Patrick Carlson	405,758	436,945	--	--
Jakub Brogowski	71,383	76,870	--	--
Sue Kuethe	68,979	74,281	--	--
Kurt Molnar	63,569	68,455	--	--
Mike Hantzsch	73,412	79,055	--	--

Plan Information

Option Plan

The purposes of the Option Plan are: (a) to provide an incentive to the directors, officers, employees, consultants and other personnel of Kiwetinohk or any of its subsidiaries to achieve the longer-term objectives of Kiwetinohk; (b) to give suitable recognition to the ability and industry of such persons who contribute materially to the success of Kiwetinohk; and (c) to attract and retain in the employ of Kiwetinohk or any of its subsidiaries, persons of experience and ability, by providing them with the opportunity to acquire an increased proprietary interest in Kiwetinohk.

Pursuant to the Option Plan, Kiwetinohk may grant Options to directors, officers, employees and service providers of Kiwetinohk, which are exercisable for one Common Share per Option. The maximum number of Common Shares issuable under the Option Plan and all other security-based compensation arrangements of the Company (excluding the Performance Warrants) must not exceed 10% of the aggregate number of issued and outstanding Common Shares from time to time (calculated on an undiluted basis).

The grant of Options under the Option Plan, together with Common Shares that may be issuable pursuant to all other security-based compensation arrangements of Kiwetinohk (excluding the Performance Warrants), will also not result at any time in: (a) the number of Common Shares issuable to insider of Kiwetinohk exceeding 10% of the aggregate number of issued and outstanding Common Shares from time to time (calculated on an undiluted basis); (b) the issuance to insiders of the Company within a one year period, of a number of Common Shares exceeding 10% of the aggregate number of issued and outstanding Common Shares from time to time (calculated on an undiluted basis); or (c) the issuance to any individual insider of the Company and such insider's associates, within a one year period, of a number of Common Shares exceeding 5% of the aggregate number of issued and outstanding Common Shares from time to time (calculated on an undiluted basis). In addition to the foregoing restrictions: (a) no Options may be granted to non-employee directors of Kiwetinohk if the granting of such Options would result in the issuance to such individuals (as a group) of a number of Common Shares exceeding 1% of the of the aggregate number of issued and outstanding Common Shares from time to time (calculated on an undiluted basis); and (b) within any one fiscal year, the total value of Options under the Option Plan, together with grants pursuant to the other security-based compensation arrangements of the Kiwetinohk (excluding the Performance Warrants), to a non-employee director, as determined by the Board (or the Compensation Committee), will not exceed a grant value of $100,000 of Options and $150,000 in total equity on the date of such grant.

The percentage maximums described above are "evergreen" provisions such that if any Options granted under the Option Plan are terminated or cancelled for any reason without the Common Shares issuable thereunder having been issued in full or if any Common Shares are issued pursuant to any Option under the Option Plan, any such Common Shares shall be available for the purposes of further Option grants under the Option Plan.

The Option Plan is administered by the Board (or the Compensation Committee). Under the Option Plan, the Board has the authority to determine the terms, limitations, restrictions and conditions, if any, applicable to an Option, provided that:

(a) the exercise price per Common Share of each Option shall be an amount at least equal to the Market Price at the time of grant of such Option;

(b) vested Options held by a holder who ceases to be an eligible participant under the Option Plan for any reason other than death or disability or termination for cause terminate upon the earlier of the expiry date of such Options and 90 days after the holder ceases to be a director, officer, employee or service provider of Kiwetinohk or its subsidiaries, and the holder does not continue in at least one of such capacities;

(c) vested Options held by a holder who ceases to be an eligible participant under the Option Plan for reason of death or disability terminate upon the earlier of the expiry date of such Options and 365 days after the holder ceases to be a director, officer, employee or service provider of Kiwetinohk or its subsidiaries;

(d) the Options of a holder who is terminated for cause terminate immediately; and

(e) the Options vest as to 1/3 of the total grant on each of the first three anniversaries of the grant date, or as otherwise determined by the Board.

The Option Plan also contains provisions which allow the Board, acting reasonably, to make such adjustments as it deems appropriate to the number of Common Shares authorized by the Option Plan and the number of Common Shares covered by grants made under the Option Plan in the event of a subdivision, redivision, consolidation, reclassification, amalgamation, merger or any other change in the corporate structure of shares of Kiwetinohk.

In the event of a change of control (as defined in the Option Plan), such as the sale or assets of Kiwetinohk and/or its subsidiaries having a fair market value greater than 50% of the fair market value of the assets of Kiwetinohk and its subsidiaries, any person acquiring more than 50% or more of the voting securities of Kiwetinohk (subject to certain exceptions) or any transaction or series of transactions where holders of the voting securities of Kiwetinohk immediately prior to such transaction(s) hold less than 50% of the voting securities Kiwetinohk or of the continuing entity following such transaction(s), the Board may, in its sole and absolute discretion and without the need for the consent of any Option holder, take one or more of the following actions contingent upon the occurrence of that change of control: (a) cause any or all outstanding Options to become vested and immediately exercisable, in whole or in part; (b) cause any outstanding Option to become fully vested and immediately exercisable for a reasonable period in advance of the change of control and, to the extent not exercised prior to that change of control, cancel that Option upon closing of the change of control; (c) cancel any Option in exchange for a substitute award, or (d) with respect to any Option held by an Option holder, cancel that Option in exchange for cash and/or other substitute consideration with a value equal to: (i) the number of Common Shares subject to that Option, multiplied by (ii) the difference, if any, between the Market Price on the date of the change of control and the exercise price of that Option; provided, that if the Market Price on the date of the change of control does not exceed the exercise price of any such Option, the Board may cancel that Option without any payment of consideration therefor.

Subject to the provisions described in the following sentence, the Board may amend, suspend or terminate the Option Plan, or any portion thereof, or any Option, at any time, and may do so without Shareholder approval. Subject to the exceptions that follow and subject to those provisions of applicable law, if any, that require the approval of Shareholders or any governmental or regulatory body (including, without limitation, the TSX), the permitted amendments include the following:

(a) amendments of a "housekeeping" or ministerial nature including, without limiting the generality of the foregoing, any amendment for the purpose of curing any ambiguity, error or omission in the Option Plan or to correct or supplement any provision of the Option Plan that is inconsistent with any other provision of the Option Plan;

(b) amendments necessary to comply with the provisions of applicable law (including, without limitation, rules, regulations and policies of the TSX and the provisions of any applicable tax law);

(c) amendments respecting the administration of the Option Plan;

(d) any amendment to the early termination provisions of the Option Plan or any grant, provided such amendment does not entail extension beyond the original Option period;

(e) amendments to the definition of security-based compensation arrangements to remove the exclusion of the Performance Warrants granted prior to the amended and restated date of the Option Plan; and

(f) amendments necessary to suspend or terminate the Option Plan.

Shareholder approval will be required for the following types of amendments:

(a) any increase in: (i) the number of Common Shares that may be issued on the exercise of Options granted pursuant to the Option Plan, if the Option Plan provides for a fixed number of Options reserved for issuance; and (ii) the percentage amount of Common Shares that may be issued on the exercise of Options granted pursuant to the Option Plan, if the Option Plan provides for a percentage amount of Common Shares reserved for issuance;

(b) any amendment which reduces the exercise price of an Option;

(c) any cancellation and reissuance of an Option;

(d) any amendment extending the term of an Option beyond its original expiry date;

(e) any amendment that increases limits imposed on non-employee director participation in the Option Plan;

(f) any amendment to remove or exceed the insider participation limits in the Option Plan;

(g) any amendment which would permit Options to be transferable or assignable, other than for normal estate settlement purposes; and

(h) amendments to the amendment and termination provisions of the Option Plan.

As at December 31, 2020, an aggregate of 1,288,289 Common Shares, representing approximately 6.9% of the outstanding Common Shares, were issuable pursuant to the exercise of Options issued pursuant to the Option Plan. Since December 31, 2020, an additional 1,319,912 Options have been issued in recognition of the achievement of a number of corporate milestones.

Performance Warrants

Kiwetinohk may grant Performance Warrants to directors, officers, employees and consultants of Kiwetinohk. Each Performance Warrant evidences a right of the holder to subscribe for and purchase one fully-paid and non-assessable Common Share, subject to any adjustments set forth in the applicable Performance Warrant certificate. For Performance Warrants granted prior to June 28, 2021 (being the date of the Business Combination Agreement), each Performance Warrant may be exercised to purchase Common Shares at or before the earlier of: (a) if the Common Shares are listed and posted for trading on the TSX or another exchange acceptable to the Board, the expiry term which may be imposed by such stock exchange; (b) August 20, 2025 for initial Performance Warrant grants or January 4, 2028 for grants in January 2021; and (c) at the sole discretion of the Board immediately following a liquidity event or a change of control (as defined in the applicable Performance Warrant certificate).

Each Performance Warrant evidences a right of the holder to subscribe for and purchase one fully-paid and non-assessable Common Share, with the following terms and conditions:

(a) the Performance Warrants are issuable in series, with an exercise price of $15.00 for Series 1; $17.50 for Series 2; $20.00 for Series 3; $22.50 for Series 4; and $25.00 for Series 5 (the foregoing reflects the exercise price per Common Share);

(b) all unvested Performance Warrants shall immediately vest upon the occurrence of a liquidity event or upon the completion of a change of control;

(c) all vested Performance Warrants held by a holder who ceases to be an eligible participant under the Performance Warrant certificate for any reason other than death or disability or termination for cause terminate 90 days after the holder ceases to be a director, officer, employee or consultant of Kiwetinohk or its subsidiaries, and the holder does not continue in at least one of such capacities;

(d) Performance Warrants generally vest as to 1/3 of each series, on each of the first three anniversaries of the grant date, although in some cases the Board has recognized historical service by granting Performance Warrants that vest as 1/4 of each series, with the first 1/4 vested at grant and the remainder to vest in rateably on each of the first three anniversaries of the grant date;

(e) unless otherwise determined by the Board, in respect of Performance Warrants held by a holder who dies or becomes disabled, the Board will have discretion to: (i) leave all vested Performance Warrants in place under their existing terms; or (ii) cause Kiwetinohk to repurchase such holder's vested Performance Warrants for the "market price" (as defined in the applicable Performance Warrant certificate) of the Common Shares issuable upon the exercise of such Performance Warrants, either in cash or Common Shares; and

(f) unless otherwise determined by the Board, the Performance Warrants of a holder who is terminated for cause terminate immediately.

The form of Performance Warrant certificate also contains provisions which allow the Board, acting reasonably, to make such adjustments as it deems appropriate to the number of Common Shares covered by the Performance Warrants granted under a certificate in the event of a subdivision, redivision, consolidation, reclassification, amalgamation, merger or any other change in the corporate structure of shares of Kiwetinohk.

At the discretion of the Board, upon the occurrence of a liquidity event, the holder of a Performance Warrant may elect to surrender the Performance Warrant in exchange for the issuance of Common Shares with a value (determined using market price) equal to the number obtained by multiplying the number of Performance Warrants surrendered by the market price (on the date of surrender) divided by the market price (on the date of surrender). Performance Warrants may not be transferred without the express approval of the Board, except by will or the laws of descent and distribution. Kiwetinohk may not provide financial assistance to the holder of a Performance Warrant in connection with the exercise of Performance Warrants.

The Board may, at any time and from time to time, without the approval of the Shareholders, amend the terms and conditions of the Performance Warrants to conform the Performance Warrants to applicable law or regulation or the requirements of the TSX or any relevant regulatory authority; provided that unless grantees holding at least 66⅔% of the Performance Warrants otherwise consent, the Board may not alter, amend or revise the terms and conditions of the Performance Warrants in a manner that may be considered to be adverse to the holders of Performance Warrants; and provided that any amendment or revision that may be considered to be adverse to the holders of Performance Warrants may only be made with the consent the Performance Warrant holders holding at least 66⅔% of the Performance Warrants that are so disproportionately and adversely affected.

As at December 31, 2020, an aggregate of 2,578,493 Common Shares, representing 13.8% of the outstanding Common Shares, were issuable pursuant to the exercise of Performance Warrants. Since December 31, 2020, an additional 5,259,497 Performance Warrants have been issued in recognition of the achievement of a number of corporate milestones. The Board does not intend to issue Performance Warrants in any material quantity going forward.

Distinction Options

The Company assumed the Distinction Options in connection with the Business Combination and does not intend to grant Distinction Options on a go forward basis.

The Distinction Options are fully vested and entitle the holders thereof to acquire in the aggregate 608,872 Common Shares at an exercise price of $7.50 per Common Share.

In the event the Common Shares are listed on the TSX or a comparable stock exchange by May 31, 2022, the Distinction Options shall only be exercisable for 100 days following such listing.

In the event that the Company amalgamates, consolidates or mergers into another corporation, the holders of Distinction Options will thereafter receive upon exercise the securities or property to which a holder of the number of Common Shares then deliverable upon the exercise of the Distinction Option would have been entitled to upon such amalgamation, consolidation or merger.

Termination and Change of Control Benefits

The Company has employment agreements with each of its NEOs.

NEO Employment Agreements

The employment agreement with each NEO of the Company other than Patrick Carlson provides that, in the event the Company terminates such NEO's employment without cause, the Company must provide the terminated NEO with payment in lieu of notice in an amount equivalent to: (i) six (6) months' of such NEO's annual base salary; plus (ii) two (2) months' of such NEO's annual base salary for each completed year of service with the Company, up to a maximum of twelve (12) months' of their annual base salary. For the purposes of the foregoing, "cause" is defined to include a material breach of the NEO's employment agreement, failure to perform their duties or to comply with Company policy, or any dishonest act, breach of fiduciary duties owed to the Company, or anything else that could constitute just cause at common law.

The Company's employment agreement with Mr. Carlson provides that, in the event the Company terminates Mr. Carlson's employment for any reason other than just cause, death or disability, as further described in the relevant employment agreement, the Company must pay an amount equal to the following amounts, less applicable deductions and withholdings required by law: (i) all accrued but unpaid salary for services rendered up to the termination date; (ii) the pro-rated value of any accrued but unused vacation entitlements; (iii) any accrued but unpaid expenses required to be reimbursed at the termination date; (iv) payment in lieu of termination notice as required by the *Employment Standards Code* (Alberta); (v) any declared but unpaid bonus as at the termination date; (vi) a severance amount equal to the monthly salary as at the termination date times a factor equal to the sum of 15 plus an additional three for each completed year of service under such employment agreement (provided that the factor shall not in any event exceed 24 and provided further that "salary" for the purposes of determining such payment shall be the greater of Mr. Carlson's actual salary at that time and $250,000); and (vii) an amount equal to 7.5% of the amount paid under subsections (iv) and (vi) as compensation for the loss of employment benefits, which shall cease on the termination date (collectively, the "**Termination Benefits**").

For the purposes of the foregoing, "just cause" means any reason which would entitle the Company to terminate Mr. Carlson's employment without notice or payment in lieu of notice at common law and includes but is not limited to: (i) fraud, misappropriation of company property, assets or funds, embezzlement, malfeasance, misfeasance or nonfeasance in office which is willfully or grossly negligent on the part of the executive; (ii) conviction of, or plea (other than not guilty) by the executive to a criminal offence involving dishonesty or fraud, or which is likely to injure the Company's business or reputation; (iii) the willful allowance by the executive of his duty to the Company and the executive's personal interests to come into conflict in a material way in relation to any transaction or matter that is of a substantial nature; (iv) the material breach by the executive of any covenants or obligations under the employment agreement; (v) the failure by the executive to substantially perform his obligations in accordance with his employment agreement after the Company has given him reasonable notice of such failure and a reasonable opportunity to correct, or cause to be corrected, such failure; (vi) the intentional or negligent involvement or participation by the executive in any act which is materially injurious to the Company, financially or otherwise; or (vii) any information, reports, documents or certificates being furnished by the executive to the Board or any committee thereof which are intentionally false or misleading because they either include or fail to include material facts, including without limitation disclosure of conflicts of interest.

With respect to Mr. Carlson only, in the event that there is a change of control and there is no termination for just cause, the Company must pay Mr. Carlson an amount equal to the Termination Benefits, provided that the amount payable under subsection (vi) above be Mr. Carlson's monthly salary, being the greater of his salary at the time of the change of control and $250,000, times a factor of 24. For the purposes of the employment agreement with Mr. Carlson, a "change of control" is defined to mean: (i) the acquisition of shares, or securities convertible into shares, of the Company, as a result of which the acquiring entity beneficially owns or exercises control or direction over shares which would entitle the acquiring entity to cast more than 50% of the votes attached to all shares in the capital of the Company which may be cast to elect directors of the Company; or (ii) the occurrence of: (a) an amalgamation, arrangement, merger or other consolidation of the Company whereby the acquiring entity beneficially owns or exercises control or direction over shares which would entitle the acquiring entity to cast more than 50% of the votes attached to all shares in the capital of the Company which may be cast to elect directors of the Company; (b) a liquidation, dissolution or winding up of the Company; or (c) a sale, lease or other disposition of all or substantially all of the assets of the Company.

Termination Payments

The following table summarizes the incremental payments that would be received by each NEO in each circumstance where the NEO ceases to be employed by Kiwetinohk. The amounts shown in the table below are calculated based on positions held at December 31, 2020. These amounts do not include Options, Performance Warrants or compensation changes subsequent to the 2020 year-end. For purposes of this table, the termination date of each NEO is assumed to be December 31, 2020. For purposes of calculating the value of the Options and Performance Warrants upon termination, the share price on December 31, 2020 of $10.00 less the applicable exercise price was utilized.

Name and Principal Position	Termination for Cause	Termination other than for Cause[(1)(2)]	Termination upon Change of Control[(1)]
Patrick Carlson			
Cash severance	--	$ 547,837	$ 250,000
Options (unvested and accelerated)	--	--	--
Performance Warrants (unvested and accelerated)	--	--	--
Total	--	$ 547,837	$ 250,000
Jakub Brogowski			
Cash severance	--	$ 250,000	--
Options (unvested and accelerated)	--	--	--
Performance Warrants (unvested and accelerated)	--	--	--
Total	--	$ 250,000	--
Sue Kuethe			
Cash severance	--	$ 235,000	--
Options (unvested and accelerated)	--	--	--
Performance Warrants (unvested and accelerated)	--	--	--
Total	--	$ 235,000	--
Kurt Molnar			
Cash severance	--	$ 195,833	--
Options (unvested and accelerated)	--	--	--
Performance Warrants (unvested and accelerated)	--	--	--
Total	--	$ 195,833	--

Name and Principal Position	Termination for Cause	Termination other than for Cause(1)(2)	Termination upon Change of Control(1)
Mike Hantzsch			
Cash severance	--	$ 250,000	--
Options (unvested and accelerated)	--	--	--
Performance Warrants (unvested and accelerated)	--	--	--
Total	--	$ 250,000	--

Notes:

(1) Cash severance calculations based on salary are based on annual salary for the year ended December 31, 2020.

(2) In addition, any NEO terminated for any reason other than just cause shall be entitled to: (i) all accrued but unpaid salary for services rendered up to the termination date; (ii) the pro-rated value of any accrued but unused vacation entitlement as at the termination date for that portion of the calendar year in which the NEO was actively employed; (iii) any accrued but unpaid expenses at the termination date required to be reimbursed pursuant to such NEO's employment agreement; and (iv) any declared but unpaid bonus as at the termination date.

Director Compensation

Approach to Director Compensation

Kiwetinohk pays director compensation to attract and retain directors of the quality and with the skills required to oversee Kiwetinohk's business, taking into account the complexity of Kiwetinohk's operations and business. Kiwetinohk compensates directors for their accountability and risk, responsibility and preparation, on the basis that they devote time and attention to Kiwetinohk year-round and to reflect their fiduciary oversight and effectiveness. Kiwetinohk directors oversee Kiwetinohk's business and affairs on behalf of the shareholders and in the best interests of Kiwetinohk.

Kiwetinohk presently has no formal compensation arrangements for its directors. All compensation paid to directors to date has been in the form of Options and Performance Warrants. As with share-based compensation awards to officers and employees, awards of Options and Performance Warrants to directors have been ad hoc in nature and tied to the achievement of broader corporate milestones.

Directors are also reimbursed for transportation and other out-of-pocket expenses reasonably incurred for attendance at Board and committee meetings and in connection with the performance of their duties as directors.

Details of 2020 Director Compensation

The following table sets forth all amounts of compensation provided to the directors (other than Patrick Carlson who received no compensation in his capacity as a director) for the year ended December 31, 2020.

Name	Fees Earned ($)	Share-Based Awards ($)	Option/ Warrant-Based Awards ($)	Non-Equity Incentive Plan Compensation ($)	Pension Value ($)	All Other Compensation ($)	Total ($)
Kevin Brown	nil	nil	nil	nil	nil	nil	nil
William (Bill) Slavin	nil	nil	nil	nil	nil	nil	nil
Leland Corbett	nil	nil	nil	nil	nil	nil	nil
Kaush Rakhit	nil	nil	nil	nil	nil	nil	nil

Outstanding Share-Based Awards and Option-Based Awards — Directors

The following tables set forth all awards outstanding for each of the directors (other than Patrick Carlson, who received no awards in his capacity as a director) at the end of December 31, 2020, including awards granted before December 31, 2020.

Name	Option-Based Awards				Share-Based Awards		
	Number of Securities Underlying Unexercised Options (#)[1]	Options Exercise Price ($)	Option Expiration Date	Value of Unexercised in-the-money Options ($)[2]	Number of Shares or Units of Shares that have not Vested (#)	Market or Payout Value of Share-Based Awards that have not Vested ($)	Market or Payout Value of Vested Share-Based Awards not Paid out or Distributed ($)
Kevin Brown[4]	35,000	$10.00	October 3, 2025	--	--	--	--
William (Bill) Slavin[4]	35,000	$10.00	October 3, 2025	--	--	--	--
Leland Corbett	35,000	$10.00	October 3, 2025	--	--	--	--
Kaush Rakhit	35,000	$10.00	October 3, 2025	--	--	--	--

Name	Performance Warrant-Based Awards			
	Number of Securities Underlying Unexercised Warrants (#)[1]	Warrant Exercise Price ($)	Warrant Expiration Date	Value of Unexercised in-the-money Warrants ($)[2]
Kevin Brown[4]	70,000	$20.00	October 3, 2025	--
William (Bill) Slavin[4]	70,000	$20.00	October 3, 2025	--
Leland Corbett	70,000	$20.00	October 3, 2025	--
Kaush Rakhit	70,000	$20.00	October 3, 2025	--

Name	Capital Warrant-Based Awards[3]			
	Number of Securities Underlying Unexercised Warrants (#)	Warrant Exercise Price ($)[3][4][5]	Warrant Expiration Date	Value of Unexercised in-the-money Warrants ($)[2]
Kevin Brown[4]	--	--	August 20, 2025	--
William (Bill) Slavin[4]	--	--	August 20, 2025	--
Leland Corbett	39,000	$10.00+	August 20, 2025	--
Kaush Rakhit	130,000	$10.00+	August 20, 2025	--

Notes:

(1) Since December 31, 2020, an additional 114,812 Options and 414,120 Performance Warrants have been granted to the directors of Kiwetinohk (other than Mr. Carlson, who received no awards in his capacity as a director).

(2) Based on the last equity price that Common Shares were issued in 2020 on April 23, 2021 at $10.00 per Common Share.

(3) All Capital Warrants were cancelled upon completion of the Business Combination and no Capital Warrants remain outstanding.

(4) Options, Performance Warrants and Capital Warrants granted to Kevin Brown and William (Bill) Slavin are held by such individuals for the benefit of ARC (or its fund manager or general partner).

Incentive Plan Awards — Value Vested or Earned During the Year — Directors

The following table sets forth incentive plan awards for each director for value vested or earned during the year ended December 31, 2020 (other than Patrick Carlson, who received no awards in his capacity as a director).

Name	Option/Warrant-Based Awards — Value Vested During the Year ($)	Share-Based Awards — Value Vested During the Year ($)	Non-Equity Incentive Plan Compensation — Value Earned During the Year ($)
Kevin Brown[1]	98,315	--	--
William (Bill) Slavin[1]	98,315	--	--
Leland Corbett	98,315	--	--
Kaush Rakhit	98,315	--	--

Note:

(1) Options, Performance Warrants and Capital Warrants granted to Kevin Brown and William (Bill) Slavin are held by such individuals for the benefit of ARC (or its fund manager or general partner).

Indemnity Agreements for Directors and Officers

Kiwetinohk has entered into indemnity agreements with each of the directors and officers pursuant to which Kiwetinohk has agreed to indemnify such directors and officers from liability arising in connection with the performance of their duties. Such indemnity agreements conform to the provisions of the CBCA.

Compensation Governance

Compensation Related Risk Management

The Company's compensation program is designed to provide officers incentives for the achievement of near-term and long-term objectives, without motivating them to take unnecessary risk.

The Board provides regular oversight of Kiwetinohk's risk management practices, and delegates to the Compensation Committee the responsibility to provide risk oversight of Kiwetinohk's compensation policies and practices, and to identify and mitigate compensation policies and practices that could encourage inappropriate or excessive risk taking by members of senior management.

The Compensation Committee and the Board considered the implications of the risks associated with Kiwetinohk's compensation practices and did not identify any risks from Kiwetinohk's compensation policies or practices that are likely to have a material adverse effect on Kiwetinohk.

The Compensation Committee and the Board have concluded that Kiwetinohk has policies and practices to ensure that employees do not have incentives to take inappropriate or excessive risks.

Independent Advice

Based on information which is publicly available, the Compensation Committee exercises its business judgment in setting base salaries and incentive compensation levels for executive officers. This includes an evaluation of each executive officer's qualifications and performance as well as company-wide performance. An executive officer's success in achieving business results and demonstrating leadership are also taken into account when reviewing base salaries.

In prior years, Kiwetinohk did not award long-term incentive awards based on the fact that the initial awards were intended to compensate employees fairly until all of the initial ARC option to invest was either placed or declined. ARC invested, taking up all of its option to invest (plus additional capital) in conjunction with the closing of the Simonette Acquisition. Options and Performance Warrants were accordingly granted to each employee earlier in 2021. Performance will continue to be a factor in setting long-term incentive award values and, in addition, Kiwetinohk will determine long-term incentive award levels with a view to delivering an appropriate mix of compensation, weighted to long-term incentives, on a market competitive basis.

Share Ownership Requirements

Executive Officers and Other Employees

The Company has adopted the following share ownership guidelines, pursuant to which the Company's executive officers and any other employee specified by the Board are required to hold, directly or indirectly, Common Shares with an aggregate value as follows:

Participant	Share Ownership Guideline
CEO	3x base salary
CFO	1.5x base salary
Other Officers and Participants	1.5x base salary

Common Shares are valued at the higher of: (a) value at the time of award or acquisition; and (b) the current market price of the Common Shares. Each officer will have five years from the later of the introduction of the executive share ownership guidelines and the date of their election or appointment as an officer to achieve this minimum share ownership requirement.

Non-Executive Directors

In recognition of the importance of ensuring an alignment of financial interests of non-executive directors with those of shareholders, the Company has adopted an equity ownership requirement for its non-executive directors. Each non-executive director are required to hold, directly or indirectly, Common Shares with an aggregate value equal to or greater than three times the non-executive director's previous year's cash retainer fee. Common Shares are valued at the higher of: (a) value at the time of award or acquisition; and (b) the current market price of the Common Shares. Each non-executive director will have five years from the later of the introduction of the non-executive director share ownership guidelines and the date of their election as a director to achieve this minimum share ownership requirement.

Hedging Prohibition

The Company's securities trading and reporting policy provides that no director, officer or employee may, at any time, purchase financial instruments, including prepaid variable forward contracts, instruments for the short sale or purchase or sale of call or put options, equity swaps, collars, spread bets, contracts for difference or units of exchangeable funds, that are designed to hedge or offset, or that may reasonably be expected to have the effect of hedging or offsetting, a decrease in the market value of any of the Company's securities or may otherwise take any speculative or derivative positions of any kind which would have or that may reasonably be expected to have such effect. To the Company's knowledge, none of the directors or Named Executive Officers have purchased any such financial instruments.

Clawback Policy

The Company believes that an important part of managing compensation risk and promoting ethical conduct is setting the appropriate tone at the executive level, and the Company believes that having an appropriate clawback policy is an important part of setting that tone. The Company has adopted a policy whereby, in the event fraud or wilful misconduct by an executive officer resulting in inaccurate financial results being reported or negligent conduct resulting in the restatement of all or any part of Kiwetinohk's financial statements: (a) such executive officer is required to reimburse the Company for an amount equal to the difference between any incentive compensation he or she received or became entitled to in respect of the year in which the misconduct occurred and the amount of such incentive compensation the executive officer should have properly received using corrected financial results; and (b) the Board has the discretion to cancel, withhold or otherwise take appropriate action to recoup that executive officer's incentive compensation paid during the 12-month period following the first public issuance or filing with securities regulatory authorities, whichever first occurs, of the financial document embodying the erroneous financial reporting results.

APPENDIX "E"

Statement of Corporate Governance Practices

The disclosure set out below includes disclosure required by NI 58-101 describing the Company's approach to corporate governance.

Board of Directors

The Board of Directors of the Company consists of the following individuals, a majority of which are independent:

Name of Individual	Status on Board
Patrick Carlson	Director and CEO of Kiwetinohk; President, CEO; Non-Independent
Kevin Brown	Director, Chair of the Board; Non-Independent
Kaush Rakhit	Director, Independent
Leland Corbett	Director, Independent
Nancy Lever	Director, Independent
Steve Sinclair	Director, Independent
Timothy Schneider	Director, Independent
Beth Reimer-Heck	Director, Independent

Prior to the Business Combination, the Board was governed by a small board of directors that met formally at least quarterly, to consider committee reports and perform general governance functions. The Board held frequent *ad hoc* meetings to consider material investments, material commitments and strategy.

Under NI 58-101, a director is considered to be independent if he or she is independent within the meaning of NI 52-110. Pursuant to NI 52-110, an independent director is a director who is free from any direct or indirect relationship which could, in the view of the Board, be reasonably expected to interfere with a director's independent judgment. Based on the Board's knowledge of each director's relationships with the Company as well as information provided by each director, the Board has determined that: (a) Mr. Rakhit, Mr. Corbett, Ms. Lever, Mr. Sinclair, Mr. Schneider and Ms. Reimer-Heck are independent within the meaning set out in NI 58-101; (b) Mr. Carlson is not independent within the meaning set out in NI 58-101 as he is the CEO of Kiwetinohk; and (c) Mr. Brown is not independent within the meaning set out in NI 58-101 as he is an executive officer and/or director of ARC Financial Corp. and of the general partners of the limited partnerships comprising ARC, which hold an aggregate of approximately 63% of the issued and outstanding Common Shares as of the date of this AIF.

With respect to Mr. Rakhit, although he is an executive officer, director and owner of a company which provides certain products and services to Kiwetinohk, the Board has determined that Mr. Rakhit is independent and capable of exercising independent judgment after considering, among other things, (i) that Mr. Rakhit's company does not provide consulting services to the Company in which Mr. Rakhit has an active role, (ii) that Mr. Rakhit's company provides similar services to other energy companies at similar pricing, (iii) Mr. Rahkit's common share ownership position in the Company and his personal financial circumstances, and (iv) the statutory guidance with respect to the meaning of independence.

With respect to Mr. Corbett, although the law firm of which he is a partner, Stikeman Elliott LLP, provides legal services to Kiwetinohk, the Board has determined that Mr. Corbett is independent and capable of exercising independent judgment after considering, among other things, (i) that Mr. Corbett does not provide legal services to the Company, (ii) that the fees charged by Stikeman Elliott to the Company are less than 1% of Stikeman Elliott's total revenues, (iii) Mr. Corbett's equity ownership in Stikeman Elliott LLP, (iv) Mr. Corbett's common share ownership position in the Company and his personal financial circumstances, and (v) the statutory guidance with respect to the meaning of independence.

With respect to Ms. Lever, although she is an employee of ARC Financial Corp. and provides consulting services to Kiwetinohk, the Board has determined that Ms. Lever is independent and capable of exercising independent judgment after considering, among other things, (i) that Ms. Lever is not an executive officer and/or director of ARC Financial Corp. like Mr. Brown, (ii) that Ms. Lever has not been and is not an employee of the Company or remunerated for the provision of consulting services to the Company, (iii) Ms. Lever's common share ownership position in the Company and her personal financial circumstances, and (iv) the statutory guidance with respect to the meaning of independence.

With respect to Mr. Schneider, although he was the former President, Chief Executive Officer and Chairman of Distinction which was previously a subsidiary of the Corporation and is the director nominee of Luminus, the Board has determined that Mr. Schneider is independent and capable of exercising independent judgment after considering, among other things, (i) that Luminus is not an "affiliated entity" of the Corporation since it only holds 11.9% of the Common Shares, (ii) that Mr. Schneider was an interim Chief Executive Officer and part-time Chairman of Distinction given that he was the Chief Executive Officer of Distinction for only 11 weeks, his Chairman role was not full-time nor subject to full-time compensation and the other circumstances relating to such positions, (iii) Mr. Schneider's common share ownership position in the Company and his personal financial circumstances, and (iv) the statutory guidance with respect to the meaning of independence.

The Board believes that given its size and structure, it is organized properly, functions effectively and is able to facilitate independent judgment in carrying out its responsibilities, including those set forth in the mandate of the Board. To enhance such independent judgement, while the Company's independent directors may not hold regularly scheduled meetings at which the non-independent directors and management are not in attendance, at the end of, or during, each Board meeting, the members of management who are present at such meeting, including the non-independent directors will leave the meeting in order that the independent directors can discuss any necessary matters without management and any non-independent directors being present.

Kevin Brown, the Chair of the Board, is not independent. However, Beth Reimer-Heck has been appointed as the Lead Director by the Board and is responsible for ensuring that the directors who are independent have opportunities to meet without management and non-independent directors, as required. The Lead Director will be appointed and replaced from time to time by a majority of independent directors and will be an independent director. Discussions among the independent directors will be led by the Lead Director who will provide feedback subsequently to the Chair.

No members of the Board are presently directors of other issuers that are reporting issuers (or the equivalent). The Company does not have a formal policy on board interlocks, however it does monitor the other public directorships held by its members. A board interlock occurs when two of the Company's directors also serve together on the board of another reporting issuer. As of the date of this AIF, there are no board interlocks among the Board members.

Majority Voting Policy

In accordance with the requirements of the TSX, the Company has adopted a majority voting policy, which requires that any nominee for director who receives a greater number of votes "withheld" from his or her election than votes "for" such election shall tender his or her resignation to the Chair following the meeting of Shareholders at which the directors were elected. This policy applies only to uncontested elections, meaning elections where the number of nominees for director is equal to the number of directors being elected. This policy shall also not apply where an election involves a proxy contest, i.e., where proxy materials are circulated, a solicitation of proxies is carried out and/or public communications are disseminated in support of one or more nominees who are not part of the director nominees supported by the Board or public communications are disseminated, against one or more nominees who are supported by the Board. The Governance and Nominating Committee shall consider the resignation and recommend to the Board whether or not to accept such resignation. In doing so, the Governance and Nominating Committee may consider any stated reasons as to why Shareholders withheld votes from the election of the relevant director, the effect such resignation may have on the Company's ability to comply with applicable corporate or securities law requirements, applicable regulations or commercial agreements regarding the composition of the Board and any other factors that the members of the Governance and Nominating Committee consider relevant. The nominee shall not participate in any meeting of the Board or of any committee of the Board at which his or her resignation is considered. The Board must accept the resignation, except in situations where exceptional circumstances would warrant the nominee continuing to serve on the Board. The Board must act on the Governance and Nominating

Committee's recommendation within 90 days following the applicable meeting of Shareholders and announce its decision through a press release after considering the factors identified by the Governance and Nominating Committee and any factors that the members of the Board consider relevant. Subject to any applicable corporate law restrictions or requirements, and the articles and by-laws of the Company, if a resignation is accepted, the Board may leave the resulting vacancy unfilled until the next annual general meeting of Shareholders. Alternatively, it may fill the vacancy through the appointment of a new director whom the Board considers to merit the confidence of the Shareholders, or it may call a special meeting of Shareholders at which there will be presented a management nominee or nominees to fill the vacant position or positions. See "*Principal Holders of Voting Securities – Investment Rights Agreement (ARC)*" and "*Principal Holders of Voting Securities – Investment Rights Agreement (Luminus)*" in the AIF.

Board Mandate

The Board, either directly or through its committees, is responsible for the supervision of management of Kiwetinohk's business and affairs with the objective of enhancing Shareholder value. A copy of the mandate of the Board is attached to this AIF as Appendix "B".

The Board has also established Board and committee guidelines for the operations of its Board and committee meetings in line with effective governance practices to provide clarity and direction to the Board and its committee members on operational meeting matters such as committee composition, voting, quorum, circulation of meeting materials and reporting expectations to the Board.

Meeting Attendances

The Board has held 10 formal Board meetings to date since January 1, 2021. Each director of Kiwetinohk attended all of the formal Board meetings.

Board Committees

The Board currently has five committees: (a) the Audit Committee, Chaired by Steve Sinclair and including Kevin Brown, Beth Reimer-Heck and Tim Schneider; (b) the Reserves Committee, Chaired by Kaush Rakhit and including Nancy Lever, and Pat Carlson; (c) the Compensation Committee, Chaired by Leland Corbett and including Nancy Lever, Steve Sinclair, and Kaush Rakhit; (d) the Sustainability Committee, Chaired by Nancy Lever and including Beth Reimer-Heck, Leland Corbett, and Pat Carlson; (e) and the Governance and Nominating Committee, Chaired by Beth Reimer-Heck and including Kevin Brown, Tim Schneider, and Leland Corbett. See "*Audit Committee Information*" in the AIF and below for a description of the roles and responsibilities of each of the committees.

Audit Committee

See "*Audit Committee Information*" in the AIF.

The primary function of the Audit Committee is to assist the Board by: (a) overseeing the nature and scope of the Corporation's annual independent audit and the integrity of the Corporation's financial statements; (b) overseeing the Corporation's external independent auditor's performance, qualifications and independence; (c) overseeing management's implementation and maintenance of an effective system of internal controls over cash management and financial reporting; (d) overseeing the Corporation's legal and regulatory compliance requirements with respect to financial management and reporting; (e) overseeing the Corporation's financial risk management programs including insurance, cash management, hedging, marketing and debt; (f) overseeing the Corporation's systems of financial disclosure control and procedures; and (g) recommending, for Board approval, the audited financial statements and other mandatory disclosure releases containing financial information.

Reserves Committee

The primary function of the Reserves Committee is to assist the Board by: (a) appointing and approving, on behalf of the Board, Kiwetinohk's independent reserves evaluator; (b) overseeing the work of the independent reserves evaluator, including understanding the nature and resolution of disagreements between such evaluator and management; and (c) reviewing the Company's procedures relating to disclosure of information with respect to oil and gas reserves and resources and other oil and gas activities.

Compensation Committee

The primary function of the Compensation Committee is to assist the Board by: (a) reviewing and approving Kiwetinohk's goals and objectives, and structuring, reviewing and approving and then recommending to the Board the compensation of the CEO and other members of the senior management team of the Company in in light of those goals and objectives; (b) structuring, reviewing and approving the compensation of each director of the Company: (c) administering Kiwetinohk's compensation plans for senior management, including stock-based compensation and such other compensation plans or structures as are adopted by the Company from time to time; (d) providing broad oversight of Kiwetinohk's compensation strategy including a charge to ensure Kiwetinohk is able to secure and maintain employment of, and train and develop the skills of persons with the talent to enable Kiwetinohk to meet its business objectives and execute its business strategies; (e) assessing the performance of the CEO and other key personnel; (g) regularly reviewing Kiwetinohk's, executive recruiting and executive skill development and succession planning processes with a view to ensuring that Kiwetinohk rigorously manages the risk of loss of hard-to-replace personnel; and (h) reviewing and approving Kiwetinohk's hiring, and employee career development practices with respect to diversity and inclusion.

Sustainability Committee

The primary function of the Sustainability Committee is to assist the Board by: (a) overseeing Kiwetinohk's policies and management systems which are designed to cause it to comply with applicable laws and regulations; (b) identifying issues and risks and opportunities to differentiate, strategies, policies and management controls designed to ensure safe and responsible operations; (c) manage risks and capture opportunities associated with sustainability matters, including health, safety, environment (including climate change) and relationships with all of the Stakeholders identified in the Corporate Mandate; (d) reviewing and commenting upon management's strategies to enhance Kiwetinohk's image among its stakeholders; and (e) evaluating the performance of Kiwetinohk with respect to the matters identified in the paragraphs above.

Governance and Nominating Committee

The primary function of the Governance and Nominating Committee is to assist the Board by: (a) ensuring effective corporate governance as one of the main factors in creating long-term sustainable value for its Shareholders; (b) reviewing the Company's policies pertaining to the Company's governance practices, values, principles or the Code of Conduct; (c) overseeing the process of assessing the effectiveness of the Board as a whole (including any committees thereof) as well as discussing the contribution of individual members; (d) overseeing the process of assessing the performance of each director of the Company; (e) periodically assessing the Company's governance, including reviewing recommendations of governance and shareholder advisory organizations and participation in benchmarking studies undertaken by such organizations to assess its governance practices in relation to those of other issues in a wide range of industries and geographies; (f) proposing new nominees for appointment to the Board; and (g) recommending to the Board to consider measures to seek the resignation or removal of directors, when deemed appropriate, and policies and measures regarding director diversity, tenure, succession and renewal initiatives.

Orientation and Continuing Education

The Governance and Nominating Committee is responsible for the orientation and continuing education of the members of the Board. As new directors join the Board, they will be provided with, among other things, corporate policies, historical information about Kiwetinohk, information on Kiwetinohk's performance and its strategic plan and an outline of the general duties and responsibilities entailed in carrying out their duties. New directors are provided the opportunity to meet with the Chair, the Lead Director, the CEO, and other members of management to discuss the role and responsibilities of individual directors, the Board and its committees and to gain an understanding and appreciation for the Company's business, operations, strategic objectives and core values. The Company provides such other orientation and information as requested.

Kiwetinohk encourages and with the approval of the Chair will cover expenses associated with directors attending, enrolling or participating in courses and/or seminars dealing with financial literacy, corporate governance and related matters. Each director of Kiwetinohk has the responsibility for ensuring that he or she maintains the skill and knowledge necessary to meet his or her obligations as a director.

Ethical Business Conduct

The Board encourages and promotes an overall culture of ethical business conduct by promoting compliance with applicable laws, rules and regulations, providing guidance to employees to help them recognize and deal with ethical issues, promoting a culture of open communication, honesty and accountability and ensuring awareness of disciplinary action for violations of ethical business conduct. In connection with its commitment to ensuring the ethical operation of the Company, the Board has adopted the Code of Conduct, a copy which is available under the Company's profile at www.sedar.com. The Board looks to the CEO to advance Kiwetinohk's business in accordance with the Code of Conduct. The Code of Conduct prescribes the expectations Kiwetinohk has of those in its service with respect to communicating with and satisfying stakeholders. Each director, officer, employee, contractor, consultant, representative and agent of the Company must comply with the code of business ethics. Compliance with the code of business ethics is a condition of employment for each employee of the Company. Employees are obligated to promptly report any problems or concerns or any potential or actual violation of the Code of Conduct in accordance with the procedures established therein. The Board monitors compliance with the code of business ethics through reports of management to the Board and requires that all persons subject to the Code of Conduct provide an annual certification of compliance with the Code of Conduct.

In accordance with the CBCA, directors of the Company are subject to the statutory duties of care and loyalty, the latter of which requires directors to act as a fiduciary in the best interests of the corporation while considering the interests of individual stakeholders (or classes thereof) and treating them equitably and fairly. These duties require directors to make full disclosure of and take active steps to avoid conflicts of interest and mandate that directors, both during their term and after, are precluded from making use of any corporate opportunities, which at all times remain the property of the corporation. Kiwetinohk expects its directors to comply with these duties at all times.

The Company wishes to instill in its employees and contractors the duty to ask questions and vocalize concerns, to detect potential violations of questionable or inappropriate practices early, and, moreover, to earn a reputation for a workplace where questions are raised routinely without fear of any form of discrimination, retaliation or harassment. The Board has accordingly also adopted a whistleblower policy which provides directors, officers, employees, service providers, suppliers and contractors with the ability to report, on a confidential and anonymous basis, any violations within Kiwetinohk including (but not limited to) questionable business practices, inappropriate accounting treatment, inadequate internal controls, auditing matters (including misleading or excessive influence), disclosure of fraudulent or misleading financial information, fraud, misappropriation of corporate assets, any activity believed to be illegal, unethical or dangerous to people or the bio/physical environment, breaches of the Code of Conduct, actions that have the effect of concealing any of the forgoing, or general complaint. The Board believes that providing a forum for directors, officers, employees, service providers, suppliers and contractors to raise concerns about ethical conduct and treating all complaints with the appropriate level of seriousness foster a culture of ethical conduct.

Nomination of Directors

The Board has a Governance and Nominating Committee which is responsible for selecting nominees for election to the Board. The majority of the members of the Governance and Nominating Committee are independent. The Governance and Nominating Committee is responsible for recommending suitable candidates for nomination for election or appointment as director, and recommending the criteria governing the overall composition of the Board and governing the desirable characteristics for directors. In making such recommendations, the Governance and Nominating Committee is expected to consider: (a) the competence and skills that the Board considers to be necessary for the Board, as a whole, to possess; (b) the competence and skills of the existing members of the Board; (c) the needs of the Board and the competencies and skills each new nominee would bring to the Board; (d) any contractual arrangements of the Company that provide third party nomination rights; (e) whether or not each new nominee can devote sufficient time and resources to his or her duties as a member of the Board; and (f) any diversity and inclusion policy of the Board.

The Governance and Nominating Committee will also review, on a periodic basis, the composition of the Board, and will analyze the needs of the Board and recommend nominees who meet such needs.

ARC and Luminus have, in certain circumstances, the right to nominate members to the Board under the Investment Rights Agreement (ARC) and the Investment Rights Agreement (Luminus), respectively. See "*Principal Holders of Voting Securities – Investment Rights Agreement (ARC)*" and "*Principal Holders of Voting Securities – Investment Rights Agreement (Luminus)*".

Compensation

The Compensation Committee is responsible for determining compensation for the directors. The members of the Compensation Committee are independent. The Compensation Committee is responsible for determining compensation for the CEO and other officers. See "*Compensation Discussion and Analysis*" in Appendix "D" and "*Board Committees – Compensation Committee*" in this Appendix "E".

Board Assessments

The Governance and Nominating Committee is responsible for assessing the Board, its committees and the individual directors. This is done through structured interviews with each Board and committee member. The results of these interviews for the Board and each director will be compiled by the chair of the Governance and Nominating Committee and discussed with the Chair (if they are different individuals) and then communicated to the entire Board. The results of the individual committee interviews are compiled by the chair of that committee and discussed with the Chair after which they are communicated to the entire Board.

The Governance and Nominating Committee, with the participation of the Chair, may recommend changes to enhance Board performance based on these communications as well as based on its review and assessment of the Board structure and individuals in relation to current industry and regulatory expectations.

Position Descriptions

The Board has approved written position descriptions or terms of reference for the Chair, the Lead Director and the chair of each of the Audit Committee, the Reserves Committee, the Compensation Committee, the Sustainability Committee and the Governance and Nominating Committee. The Board has also developed a written position description for the CEO.

Director Term Limits and Other Mechanisms of Board Renewal

Kiwetinohk has not implemented formal term limits for its directors. Kiwetinohk values the comprehensive knowledge of the Company and its operations that long-serving directors possess and the contribution that this makes to the Board as a whole. The Governance and Nominating Committee, in proposing nominees to the Board, will take into consideration whether any board renewal is necessary.

Policies Regarding the Representation of Women on the Board

Kiwetinohk has not adopted a policy, written or otherwise, regarding the representation of women on the Board. While Kiwetinohk does not have a specific policy, Kiwetinohk considers diversity of race, ethnicity, gender, age, national origin, First Nations status, disability, sexual orientation, visible minority status, cultural background, professional experience and other factors in evaluating candidates for Board membership. The Board acknowledges the importance of diversity, including gender diversity, in the review and consideration of potential director nominees. The Board evaluates potential nominees to the Board by reviewing individual qualifications of prospective members and determining if the candidates' qualifications will meaningfully contribute to the effective functioning of the Board, taking into consideration the then current Board composition or diversity and the anticipated skills required to round out the capabilities of the Board.

Consideration of the Representation of Women in the Director Identification and Selection Process

Embracing and promoting diversity is a value of Kiwetinohk. The Board considers the level of representation of women on the Board in identifying and nominating Board members. The number of women directors on the Board is a factor that the Governance and Nominating Committee will consider when selecting new nominees for the Board having regard to then current and future Board composition, and the anticipated skills required to round out the capabilities of the Board, including knowledge and diversity of membership. Selection of candidates to the Board will be, in part, dependent upon the pool of such candidates with the necessary skills, knowledge and experience. The ultimate decision will be based on merit and contribution the chosen candidate will bring to the Board.

Consideration Given to the Representation of Women in Executive Officer Appointments

The Board considers the level of representation of women in executive officer positions when making executive officer appointments. Kiwetinohk is committed to the fundamental principles of equal employment opportunities with a foundation based on treating people fairly, with respect and dignity, and to offering equal employment opportunities based upon an individual's qualifications and performance free from discrimination or harassment because of race, colour, ancestry, place of origin, religion, gender, sexual orientation, age, marital status, family status, physical or mental disability. Furthermore, Kiwetinohk's employment procedures provide that the primary considerations for selecting candidates would include experience, skill and ability, while giving consideration to the importance of diversity, including gender diversity, when recruiting employees and when appointing executive officers. Kiwetinohk acknowledges the importance of diversity, including gender diversity, in the workplace.

Targets Regarding the Representation of Women on the Board and in Executive Officer Positions

Kiwetinohk has not adopted a target regarding women on the Board or women in executive officer positions. When filling any vacant or new positions, the focus is on attracting the competencies that best meet the needs of the Board or Kiwetinohk at the relevant point in time. In reviewing Board composition, the Governance and Nominating Committee will consider all aspects of diversity including, but not limited to, gender. While Board diversity is a key critical consideration, all Board appointments are made on merit, in the context of skills, experience, independence and knowledge which the Board as a whole requires to be effective. For Executive Officer positions, Kiwetinohk's focus is on attracting the competencies that best meet the needs of Kiwetinohk at the relevant point in time, with the intention of having women represented at all levels of the organization. Kiwetinohk takes the approach of continually striving to improve through the creation and implementation of policies and the fostering of a culture that is encouraging and accepting of diversity, rather than setting targets.

Number of Women on the Board and in Executive Officer Positions

As of the date of this AIF, Kiwetinohk has two women on the Board of nine directors (22%): Ms. Lever and Ms. Reimer-Heck. As of the date of this AIF, Kiwetinohk has three executive officers that are women (30%).

APPENDIX "F"

2020 Reserves Report Summaries

The tables below summarize the data contained in the 2020 Reserves Reports and, as a result, may contain slightly different numbers than such report due to rounding. Due to rounding, certain columns may not add exactly. This Appendix "F" should be read in conjunction with Appendix "A", "*Reserves Information – Statement of Reserves Data*" and "*Reserves Information – Disclosure of Reserves Data*" in the AIF.

2020 Kiwetinohk Reserves Report

Summary of Reserves (Forecast Prices and Costs)

Summary of Reserves
As of December 31, 2020

Reserves Category	Conventional Natural Gas		Shale Gas[2]		NGL[3]	
	Gross	Net	Gross	Net	Gross	Net
	(mmcf)	*(mmcf)*	*(mmcf)*	*(mmcf)*	*(mbbl)*	*(mbbl)*
Proved:						
Developed Producing	1,586.8	1,477.6	-	-	91.4	78.8
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	14,510.5	13,908.5	77,162.1	72,834.5	8,690.0	7,481.6
Total Proved[1]	16,097.3	15,386.1	77,162.1	72,834.5	8,781.4	7,560.5
Total Probable	20,315.7	19,401.4	19,488.8	18,171.2	3,175.5	2,589.0
Total Proved plus Probable[1]	36,412.9	34,787.5	96,650.9	91,005.7	11,956.9	10,149.4

Reserves Category	Light and Medium Crude Oil		Heavy Crude Oil		Total	
	Gross	Net	Gross	Net	Gross	Net
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mboe)*	*(mboe)*
Proved:						
Developed Producing	531.5	472.7	18.0	16.0	905.4	813.8
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	5,448.9	5,161.9	132.2	117.7	29,549.9	27,218.5
Total Proved[1]	5,980.4	5,634.6	150.2	133.7	30,455.2	28,032.2
Total Probable	7,592.7	6,986.4	289.1	255.9	17,815.5	16,203.7
Total Proved plus Probable[1]	13,573.1	12,621.0	439.3	389.5	48,146.5	44,125.4

Notes:
(1) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "Glossary, Selected Abbreviations and Selected Conversions" in Appendix "A" to the AIF.
(2) On July 1, 2021, 20 quarter sections of land with attributed reserves were surrendered to another industry participant.
(3) Figures include NGL for both conventional and unconventional reservoirs, including condensate, pentane plus, propane, butane and ethane. Condensate is expected to be extracted in the field and sold separately from other NGL or sold with other NGL delivered to fractionation facilities.

Net Present Values of Future Net Revenue
Before Income Taxes Discounted At (%/Year)
As of December 31, 2020
Forecast Prices and Costs[1]

Reserves Category	0%	5%	10%	15%	20%	Unit Value Discounted at 10% per Year $/boe[3]
	($mm)	*($mm)*	*($mm)*	*($mm)*	*($mm)*	
Proved:						
Developed Producing	20.5	17.7	15.7	14.1	12.8	19.2
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	391.9	244.5	156.2	100.4	63.2	5.7
Total Proved[2]	412.3	262.2	171.9	114.4	76.1	6.1
Total Probable	398.0	219.7	133.4	86.8	59.5	8.3
Total Proved plus Probable[2]	810.4	481.9	305.3	201.2	135.6	6.9

Notes:
(1) Estimates of future net revenue do not represent fair market value.
(2) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "Glossary, Selected Abbreviations and Selected Conversions" in Appendix "A" to the AIF.
(3) The unit values are based on net reserve volumes.

Reserves Category	Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/Year) As of December 31, 2020 — Forecast Prices and Costs(1)				
	0%	5%	10%	15%	20%
	($mm)	*($mm)*	*($mm)*	*($mm)*	*($mm)*
Proved:					
Developed Producing	20.5	17.7	15.7	14.1	12.8
Developed Non-Producing	-	-	-	-	-
Undeveloped	391.9	197.6	123.7	76.7	45.4
Total Proved(2)	340.4	215.4	139.4	90.7	58.2
Total Probable	305.8	166.8	99.4	63.4	42.5
Total Proved plus Probable(2)	646.2	382.2	238.8	154.1	100.7

Notes:
(1) Estimates of future net revenue do not represent fair market value.
(2) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "Glossary, Selected Abbreviations and Selected Conversions" in Appendix "A" to the AIF.

Total Future Net Revenue (Undiscounted)
As of December 31, 2020

Reserves Category	Revenue(1)	Royalties(2)	Operating Costs	Development Costs	Abandonment and Reclamation Costs(3)	Future Net Revenue Before Income Taxes(4)	Future Income Tax Expenses	Future Net Revenue After Income Taxes(4)
	($mm)	*($mm)*	*($mm)*	*($mm)*	*($mm)*	*($mm)*	*($mm)*	*($mm)*
Total Proved(5)	1,239.1	121.6	363.3	333.6	8.3	412.3	71.9	340.4
Total Proved plus Probable(5)	2,152.4	225.1	616.9	486.9	13.1	810.4	164.2	646.2

Notes:
(1) Total revenue includes revenue before royalties and includes other income.
(2) Royalties include Crown, freehold and overriding royalties, mineral tax and net profit interest payments.
(3) Abandonment and reclamation costs are defined by NI 51-101 as all costs associated with the process of restoring Kiwetinohk's properties that have been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.
(4) Estimates of future net revenue do not represent fair market value.
(5) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserve categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "Glossary, Selected Abbreviations and Selected Conversions" in Appendix "A" to the AIF.

Future Net Revenue by Product Type
As of December 31, 2020

Reserves Category	Product Type(1)	Future Net Revenue Before Income Tax (discounted at 10%/year)(1)(2)	Unit Value Before Income Tax (discounted at 10%/year)(2)(3)
		($mm)	*($/mcf) ($/bbl)*
Proved(4)	Light and Medium Oil (including solution gas and by-products)	41.2	7.31
	Heavy Crude Oil (including solution gas and by-products)	0.4	3.29
	Shale Gas (including by-products)	130.3	1.79
	Total	**171.9**	
Proved plus Probable(4)	Light and Medium Oil (including solution gas and by-products)	119.2	9.44
	Heavy Crude Oil (including solution gas and by-products)	3.5	9.10
	Shale Gas (including by-products)	182.5	2.01
	Total	**305.2**	

Notes:
(1) The before tax future net revenue discounted at 10% for shale gas includes all by-product revenue streams from ethane, propane, butane and pentanes plus.
(2) Estimates of future net revenue do not represent fair market value. May not sum due to rounding.
(3) Unit values are based on Kiwetinohk's net reserves. Values shown for light and medium crude oil are expressed as $/bbl and values shown for conventional natural gas and shale gas are expressed as $/mcf.
(4) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained above under the heading "Glossary, Selected Abbreviations and Selected Conversions" in Appendix "A" to the AIF.

Pricing Assumptions

The forecast of prices, inflation and exchange rates provided in the table below were computed using the forecasts prepared by McDaniel, effective January 1, 2021. McDaniel's forecasts were utilized in the 2020 Kiwetinohk Reserves Report and the summary of McDaniel's evaluation that is reflected herein.

Summary of Pricing and Inflation Rate Assumptions
As of January 1, 2021

	Conventional Natural Gas and Shale Gas		NGL[(1)]				Light and Medium Crude Oil and Heavy Crude Oil				
Year	**AECO Gas Price**	**U.S. Henry Hub Gas Price US$**	**Edmonton Ethane**	**Edmonton Propane**	**Edmonton Butane**	**Edmonton Cond. & Natural Gasolines**	**WTI Cushing Oklahoma**	**Edmonton Par Price 40° API**	**Hardisty Heavy 12° API**	**Inflation Rate(2)**	**Exchange Rate(3)**
	($/mmBtu)	*(US$/mmBtu)*	*($/bbl)*	*($/bbl)*	*($/bbl)*	*($/bbl)*	*(US$/bbl)*	*($/bbl)*	*($/bbl)*	*%/Year*	*(US$/$)*
2021	2.75	2.75	10.20	15.74	21.46	61.24	47.50	57.24	46.36	0.00	0.76
2022	2.65	2.81	9.79	20.06	27.78	65.82	51.00	61.74	50.01	2.00	0.76
2023	2.55	2.86	9.36	23.61	36.21	67.13	52.02	62.97	51.01	2.00	0.76
2024	2.60	2.92	9.55	24.09	36.93	68.48	53.06	64.23	52.03	2.00	0.76
2025	2.65	2.98	9.74	24.57	37.67	69.85	54.12	65.52	53.07	2.00	0.76
2026	2.70	3.04	9.94	25.06	38.42	71.24	55.20	66.83	54.13	2.00	0.76
Thereafter		Escalated at 2.0%/yr								2.00	0.76

Notes:
(1) Figures include NGL for both conventional and unconventional reservoirs, including condensate, pentane plus, propane, butane and ethane. Condensate is expected to be extracted in the field and sold separately from other NGL or sold with other NGL delivered to fractionation facilities.
(2) Inflation rates for forecasting prices and costs.
(3) Exchange rates used to generate the benchmark reference prices in this table.

Weighted average historical prices realized (before hedging and marketing income) by Kiwetinohk for the period from January 1, 2020 to December 31, 2020, were $55.47/bbl for condensate, $7.09/bbl for other NGL (excluding condensate and pentane extracted from the gas stream), $2.28/mcf for natural gas, $48.13/bbl for light and medium crude oil and $34.40/bbl for heavy crude oil.

Reserves Reconciliation

Reconciliation of Gross Reserves by Product Type

	Conventional Natural Gas			Shale Gas		
	Gross Proved	**Gross Probable**	**Gross Proved plus Probable**	**Gross Proved**	**Gross Probable**	**Gross Proved plus Probable**
	(mmcf)	*(mmcf)*	*(mmcf)*	*(mmcf)*	*(mmcf)*	*(mmcf)*
December 31, 2019	14,769.8	17,785.2	32,555.0	-	-	-
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	1,829.7	2,530.5	4,360.2	77,162.1	19,488.8	96,650.9
Technical Revisions	-	-	-	-	-	-
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors[(2)]	-	-	-	-	-	-
Production	(502.2)	(0.1)	(502.3)	-	-	-
December 31, 2020	16,097.3	20,315.6	36,412.9	77,162.1	19,488.8	96,650.9

	NGL[(1)]			Light and Medium Crude Oil		
	Gross Proved	**Gross Probable**	**Gross Proved plus Probable**	**Gross Proved**	**Gross Probable**	**Gross Proved plus Probable**
	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)	(mbbl)
December 31, 2019	824.3	1,002.4	1,826.7	6,478.0	8,042.2	14,520.2
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	7,853.0	2,015.2	9,868.2	-	-	-
Technical Revisions	130.6	157.9	288.5	(335.0)	(449.5)	(784.5)
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors[(2)]	-	-	-	-	-	-
Production	(26.5)	-	(26.5)	(162.6)	(0.1)	(162.7)
December 31, 2020	8,781.4	3,175.5	11,956.9	5,980.4	7,592.7	13,573.1

	Heavy Crude Oil			Total boe		
	Gross Proved	**Gross Probable**	**Gross Proved plus Probable**	**Gross Proved**	**Gross Probable**	**Gross Proved plus Probable**
	(mbbl)	*(mbbl)*	*(mbbl)*	*(mboe)*	*(mboe)*	*(mboe)*
December 31, 2019	-	-	-	9,763.9	12,008.8	21,772.7
Discoveries	-	-	-	-	-	-
Extensions and Improved Recovery	132.2	-	413.2	21,150.5	5,685.1	27,116.6
Technical Revisions	-	-	-	(204.4)	(291.6)	(496.0)
Acquisitions	30.3	-	38.5	30.3	-	38.5
Dispositions	-	-	-	-	-	-
Economic Factors[(2)]		-	-	-	-	-
Production	(12.3)	-	(12.4)	(285.1)	(0.1)	(285.3)
December 31, 2020	150.2	289.1	439.3	30,455.2	17,815.5	48,146.5

Notes:

(1) Figures include NGL for both conventional and unconventional reservoirs, including condensate, pentanes plus, propane, butane and ethane. Condensate is expected to be extracted in the field and sold separately from other NGL or sold with other NGL delivered to fractionation facilities.

(2) Economic factors reflect the change in forecasted commodity prices year-over-year.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty to be recoverable where significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. Probable undeveloped reserves are those additional reserves that are less certain to be recovered than proved reserves where significant expenditure is required to render them capable of production. The 2020 Kiwetinohk Reserves Report contains proved and probable undeveloped reserves that have been estimated in accordance with the procedures and standards contained in the COGEH.

As of December 31, 2020, undeveloped reserves represented approximately 91% of total gross proved reserves and approximately 96% of gross proved plus probable reserves. The timing of proved undeveloped reserve and probable undeveloped reserve development beyond two years is due to the large land base, a well-defined drilling inventory supported by offset production, Kiwetinohk's scheduled pace of commercial development, and the timing of planned and current infrastructure construction.

The pace of development of these reserves is influenced by several factors including, but not limited to, the outcomes of drilling and reservoir evaluations, changes in commodity pricing, changes in capital allocations, changing technical conditions, access to markets, regulatory changes and impact of future acquisitions and dispositions. These reserves are reviewed and development plans are revised accordingly as new information becomes available.

The following tables set forth the gross proved undeveloped reserves and the gross probable undeveloped reserves, each by product type, attributed to Kiwetinohk for the period from January 1, 2020 to December 31, 2020, January 1, 2019 to December 31, 2019 and January 1, 2018 to December 31, 2018, based on forecast prices and costs.

Proved Undeveloped Reserves

	Conventional Natural Gas		**Shale Gas**	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
	(mmcf)		*(mmcf)*	
Jan. 1, 2018 - Dec. 31, 2018	-	-	-	-
Jan. 1, 2019 - Dec. 31, 2019	12,593.0	12,593.0	-	-
Jan. 1, 2020 - Dec. 31, 2020	-	14,510.5	77,162.1	77,162.1
	NGL(1)		**Light and Medium Crude Oil**	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
	(mbbl)		*(mbbl)*	
Jan. 1, 2018 - Dec. 31, 2018	-	-	-	-
Jan. 1, 2019 - Dec. 31, 2019	703.7	703.7	5,796.3	5,796.3
Jan. 1, 2020 - Dec. 31, 2020	7,853.0	8,690.0	-	5,448.9
	Heavy Crude Oil		**Tight Oil**	
Year	**First Attributed**	**Cumulative at Period End**	**First Attributed**	**Cumulative at Period End**
	(mbbl)		*(mbbl)*	
Jan 1, 2019 - Dec 31, 2019	-	-	-	-
Jan 1, 2020 - Dec 31, 2020	-	-	-	-
Jan 1, 2021 - June 30, 2021	132.2	132.2	-	-

Probable Undeveloped Reserves

	Conventional Natural Gas		**Shale Gas**	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
	(mmcf)		*(mmcf)*	
Jan. 1, 2018 - Dec. 31, 2018	-	-	-	-
Jan. 1, 2019 - Dec. 31, 2019	17,034.9	17,034.9	-	-

Jan. 1, 2020 - Dec. 31, 2020	-	19,815.2	19,488.8	19,488.8
	NGL[1]		Light and Medium Crude Oil	
Year	**First Attributed**	**Cumulative at Year End**	**First Attributed**	**Cumulative at Year End**
	(mmcf)		*(mmcf)*	
Jan. 1, 2018 - Dec. 31, 2018	-	-	-	-
Jan. 1, 2019 - Dec. 31, 2019	962.4	962.4	8,042.2	8,042.2
Jan. 1, 2020 - Dec. 31, 2020	2,015.2	3,146.0	(449.5)	7,592.7
	Heavy Crude Oil		**Tight Oil**	
Year	**First Attributed**	**Cumulative at Period End**	**First Attributed**	**Cumulative at Period End**
	(mbbl)		(mbbl)	
Jan 1, 2019 - Dec 31, 2019	-	-	-	-
Jan 1, 2020 - Dec 31, 2020	-	-	-	-
Jan 1, 2021 - June 30, 2021	281	281	-	-

Note:

(1) Figures include NGL for both conventional and unconventional reservoirs, including pentanes plus, propane, butane and ethane. Other NGL (propane, butane and ethane) are expected to be extracted in the field by Kiwetinohk. Condensate is expected to be extracted in the field and sold separately from other NGL or sold with other NGL delivered to fractionation facilities. Other NGL (propane, butane and ethane) are expected to be extracted in the field by Kiwetinohk.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgment and decision-making on the basis of the available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on production expectations, forecast prices and economic conditions as at December 31, 2020. Factors and assumptions that affect these reserves estimates include, among other things: (a) historical production in the area compared with production rates from analogous producing areas; (b) initial production rates; (c) production decline rates; (d) ultimate recovery of reserves; (e) success of future development activities; (f) marketability of production; (g) effects of government regulations; and (h) government levies imposed over the life of the reserves.

As circumstances change and additional data become available, reserves estimates may also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well and reservoir performance, geological conditions, production, prices, changes in corporate strategy, economic conditions and governmental restrictions. These revisions can be either positive or negative.

In connection with its operations, Kiwetinohk will incur abandonment, dismantling, reclamation and remediation costs for surface leases, wells, facilities and pipelines. Kiwetinohk budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its oil and gas assets. Kiwetinohk uses guidance from the AER and consultation with an independent third-party engineering firm to validate the estimates of such liabilities. Approximately 80% of Kiwetinohk's decommissioning liabilities on its financial statements are associated with active properties that have production and attributable reserves. There is approximately $29.5 million of inactive abandonment and reclamation costs associated with inactive wells or facilities where there is no active operations or attributed reserves. Kiwetinohk is currently working on an abandonment program to proactively manage and reduce the inactive decommissioning liabilities over the next three to five years. There are no unusually significant abandonment and reclamation costs associated with its reserves properties or to properties with no attributed reserves.

The evaluated oil and gas properties of Kiwetinohk have no material extraordinary risks or uncertainties beyond those that are inherent in unconventional oil and gas exploration and production operations. See "*Risk Factors*" in the AIF.

Future Development Costs (Forecast Prices and Costs)

The following table sets forth development costs deducted in the estimation of Kiwetinohk's future net revenue attributable to the reserves categories noted below.

Year	Annual Development Costs Total Proved	 Total Proved plus Probable
	($mm)	($mm)
2021	41.9	41.9
2022	80.8	83.6
2023	103.3	103.3
2024	85.7	110.2
2025	16.9	88.2
Thereafter	5.0	59.7
Total (Undiscounted)	**333.6**	**486.9**
Total (Discounted at 10%)	**265.5**	**364.1**

Kiwetinohk expects to fund the development costs of its reserves through current working capital, cash flow from operations, borrowings under its credit facilities and by accessing the global capital markets. There can be no guarantee that funds will be available or that the Board will allocate funding to develop all of the reserves attributed in the 2020 Kiwetinohk Reserves Report. Failure to develop those reserves could have a negative impact on Kiwetinohk's future net revenue relative to the estimates provided herein.

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

The future development costs set forth above do not include costs associated with abandonment and reclamation obligations.

Other Oil and Natural Gas Information

See AIF for a description of Kiwetinohk's important properties, plants, facilities and installations.

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which Kiwetinohk had a working interest as at December 31, 2020, all of which are located in Alberta.

Natural Gas Wells				Oil Wells			
Producing(1)		Non-Producing(1)		Producing(1)		Non-Producing(1)	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
--	--	14	11	4	4	--	--

Note:
(1) Producing wells are wells that are actively producing as of the respective date. Non-producing wells are wells that are not actively producing, and for which a reclamation certificate has not been granted, as of the respective date.

Properties with No Attributed Reserves

As at December 31, 2020, Kiwetinohk had 240,320 gross acres (217,911 net acres) to which no reserves had been attributed.

Kiwetinohk continually reviews the economic viability and ranking of these unproved properties on the basis of product pricing, capital availability, the anticipated cost to re-acquire, and the allocation and level of infrastructure development in any specific area. From this process, some properties are scheduled for economic development activities while others are temporarily held inactive, sold, swapped or allowed to expire. There is no guarantee that commercial reserves will be discovered or developed on these properties.

During 2021 approximately 10,000 net acres of the corporation have expired or will likely expire, however Kiwetinohk expects that, subject to Crown approval, approximately 45% of these lands will be continued.

None of these properties are subject to any work commitments.

When determining acreage, totals are adjusted to remove overlapping acreage under applicable petroleum and natural gas agreements.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

There are several economic factors and significant uncertainties that affect Kiwetinohk's anticipated development of its properties to which no reserves are attributed. Kiwetinohk will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil, natural gas and NGL from these properties in the future. If cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to Kiwetinohk. Failure to obtain such financing on a timely basis could cause Kiwetinohk to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations on such properties. The inability of Kiwetinohk to access sufficient capital for its exploration and development purposes could have a material adverse effect on Kiwetinohk's ability to execute its business strategy to develop these prospects. See "*Risk Factors*" in the AIF. The primary economic factors that affect the development of the properties to which no reserves have been attributed are future commodity prices for oil, natural gas and NGL (and Kiwetinohk's outlook relating to such prices) and the future costs of drilling, completing, tying-in and operating wells at the time that such activities are considered. Kiwetinohk would also need to secure adequate transportation capacity on acceptable terms for its incremental future production. The primary uncertainties that affect the development of such lands are the future drilling and completion results achieved in the development activities, drilling and completion results achieved by others on lands in close proximity to these lands, and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Conversely, uncertainty as to the timing and nature of the evolution or development of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such properties.

McDaniel has estimated undiscounted and inflated abandonment and reclamation costs of approximately $13.1 million in respect of its evaluation of Kiwetinohk's proved plus probable reserves. Kiwetinohk does not expect that these abandonment or reclamation costs will materially affect the anticipated development or production activities on its properties with no attributed reserves.

Forward Contracts and Transportation Obligations

Kiwetinohk uses risk management contracts in order to reduce its exposure to fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. All of the contracts through which Kiwetinohk has fixed the price of future production, outstanding as at December 31, 2020, as further described in the Financial Statements.

As part of normal business operations, Kiwetinohk enters into long-term commitments to transport and fractionate (as applicable) its oil, natural gas, condensate and other NGL production volumes. Transportation and fractionation of NGL are interdependent. The commitments are entered to secure capacity to market and sell these commodities, considering future growth plans, capacity constraints within the area and expectations for future transportation and fractionation costs. Accordingly, capacity deficits may arise when comparing future reserve production estimates against such commitments. See "*Commitments*" in the management's discussion and analysis of operations, financial position and outlook of Kiwetinohk for the three and six months ended June 30, 2021 and 2020, as further described in the Financial Statements.

The shortfall relative to the commitments described above reflects the future production of Kiwetinohk's proved reserves development plan. Kiwetinohk believes that holding these transportation commitments is an asset and envisions a number of ways in which the indicated impacts can be partially or wholly reduced. For example, Kiwetinohk is able to accelerate development at its discretion, depending on, among other factors, financial capacity related to prevailing commodity prices and existing field processing capacity, and Kiwetinohk mitigates a portion of its unused take-or-pay capacity through marketing transactions. Kiwetinohk is of the view that holding transportation commitments sized only to proved reserves would be insufficient relative to the production potential of its assets. Kiwetinohk believes that the transportation commitments are more accurately sized to the potential recognized within proved plus probable reserves.

Tax Horizon

As at December 31, 2020, Kiwetinohk had accumulated tax pools and loss carry forwards of approximately $108 million, including approximately $49 million in tax pools available for immediate deduction against any future taxable income. Based on anticipated capital investment, which augments the tax pools, Kiwetinohk does not expect to pay material Canadian income tax for approximately three years (based on McDaniel's forecast, see "*Pricing Assumptions*"). This estimate will be impacted by, among other factors, production volumes, commodity prices, foreign exchange rates, operating costs, interest rates, changes in tax laws and Kiwetinohk's other business activities. Changes in these factors from estimates used by Kiwetinohk could result in Kiwetinohk paying income taxes earlier than expected.

Costs Incurred

The following table summarizes the costs incurred by Kiwetinohk for the twelve months ended December 31, 2020.

	12 months ended December 31, 2020
	($mm)
Property acquisition costs:	
Proved properties	-
Unproved properties	5.5
Exploration costs	0.7
Development costs	-
Other	0.1
Total	6.3

Exploration and Development Activities

The oil and gas industry faced very challenging economic conditions during 2020 due to the outbreak of the COVID-19 pandemic and resulting lock downs of national economies coupled with the additional shock of the failure of OPEC and Russia to come to an agreement in the first half of 2020 to curtail oil production. As a result, Kiwetinohk shifted its capital focus during the year to pursuing acquisitions of producing oil and gas assets and/or companies and made a strategic decision to not allocate capital to drilling new wells. Accordingly, Kiwetinohk did not participate in any gross or net exploratory and development wells in the twelve months ended December 31, 2020 (based on rig release date).

Production Estimates

The following table sets out for each product type the gross volume (before royalties) of working interest production estimated for the year ending December 31, 2021 in the estimates contained in the 2020 Kiwetinohk Reserves Report for gross proved reserves and gross probable reserves. Actual results may differ significantly from the information below. See "*Forward-Looking Statements and Market Data*" and "*Risk Factors*" in the AIF.

Production Estimate For The Year Ending December 31, 2021

Reserve Category	**Conventional Natural Gas**	**Shale Gas**	**NGL(1)**	**Light and Medium Crude Oil**	**Heavy Crude Oil**	**Condensate(2)**	**Total**
	(mmcf)	*(mmcf)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mbbl)*	*(mboe)*
Proved	1,015	-	37	139	47	65	458
Probable	10	-	-	5	7	5	17
Total Proved plus Probable	1,025	-	37	144	54	70	475

Notes:
(1) Figures include NGL for both conventional and unconventional reservoirs, including pentanes plus, propane, butane and ethane. Other NGL (propane, butane and ethane) are expected to be extracted in the field by Kiwetinohk.
(2) Comprised of the condensate that is extracted in the field or that is otherwise sold separately from other NGL in Alberta and some condensate entrained in the NGL delivered by Kiwetinohk to fractionation facilities.

Production History

The following tables summarize certain information in respect of the production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below.

	Quarter Ended				Twelve Months Ended
	Mar. 31, 2020	**Jun. 30, 2020**	**Sept. 30, 2020**	**Dec. 31, 2020**	**Dec. 31, 2020**
Average Gross Daily Production[1]					
Conventional Natural Gas (mmcf/d)	2.2	0.7	1.6	1.0	1.4
Shale Gas (mmcf/d)	-	-	-	-	-
Natural Gas Liquids (bbl/d)					
Condensate[2]	96	13	18	13	35
Other NGL	126	25	64	41	64
Total NGL	222	38	82	54	99
Light and Medium Crude Oil (bbl/d)	620	288	435	374	429
Heavy Crude Oil (bbl/d)	-	-	15	43	15
Combined (boe/d)	1,204	443	793	645	771
Average Production Prices Received					
Conventional Natural Gas ($/mcf)	2.11	2.00	2.38	2.66	2.28
Shale Gas ($/mcf)	-	-	-	-	-
Natural Gas Liquids ($/bbl)					
Condensate[2]	60.63	34.32	43.02	55.56	55.47
Other NGL	1.73	11.97	11.15	14.04	7.09
Total NGL	27.26	19.46	18.21	23.87	24.16
Light and Medium Crude Oil ($/bbl)	51.63	42.37	46.59	48.57	48.13
Heavy Crude Oil ($/bbl)		-	31.06	35.58	34.40
Combined ($/boe)	35.42	32.44	32.74	36.83	34.60
Royalties Paid					
Conventional Natural Gas ($/mcf)	(0.29)	3.99	(0.10)	(2.08)	(0.04)
Shale Gas ($/mcf)	-	-	-	-	-
Natural Gas Liquids ($/bbl)					
Condensate[2][5]	(22.03)	17.44	(5.47)	407.48	23.41
Other NGL	(0.93)	(0.20)	(1.92)	5.52	(0.06)
Total NGL[5]	(10.08)	5.72	(2.70)	100.72	8.22
Light and Medium Crude Oil ($/bbl)	(6.00)	(4.44)	(5.37)	(5.52)	(5.48)
Heavy Crude Oil ($/bbl)	-	-	(3.12)	(4.75)	(4.33)
Combined ($/boe)	(5.46)	3.88	(3.48)	1.57	(2.14)
Production Costs[3]					
Conventional Natural Gas ($/mcf)	(0.59)	(0.60)	(0.66)	(0.72)	(0.64)
Shale Gas ($/mcf)	-	-	-	-	-
Natural Gas Liquids ($/bbl)					
Condensate[2]	(16.88)	(10.29)	(11.91)	(15.00)	(15.47)
Other NGL	(0.48)	(3.58)	(3.09)	(3.79)	(1.98)
Total NGL	(7.59)	(5.83)	(5.04)	(6.44)	(6.74)
Light and Medium Crude Oil ($/bbl)	(14.38)	(12.69)	(12.90)	(13.11)	(13.43)
Heavy Crude Oil ($/bbl)	-	-	(8.60)	(9.60)	(9.34)
Combined ($/boe)	(9.86)	(9.72)	(9.07)	(9.94)	(9.65)
Transportation Costs					
Conventional Natural Gas ($/mcf)	-	-	-	-	-
Shale Gas ($/mcf)	-	-	-	-	-
Natural Gas Liquids ($/bbl)	-	-	-	-	-
Condensate(2)	-	-	-	-	-
Other NGL	-	-	-	-	-
Total NGL	-	-	-	-	-
Light and Medium Crude Oil ($/bbl)	(1.41)	(1.29)	(1.22)	(1.68)	(1.40)
Heavy Crude Oil ($/bbl)	-	-	(0.81)	(1.23)	(1.12)
Combined ($/boe)	(0.73)	(0.84)	(0.68)	(1.06)	(0.81)
Netback Received[4][6]					
Conventional Natural Gas ($/mcf)	1.24	5.39	1.62	(0.13)	1.61
Shale Gas ($/mcf)	-	-	-	-	-
Natural Gas Liquids ($/bbl)					
Condensate[2][5]	21.72	41.49	25.64	448.04	63.41
Other NGL	0.32	8.17	6.15	15.76	5.05
Total NGL[5]	9.59	19.35	10.46	118.15	25.64
Light and Medium Crude Oil ($/bbl)	29.84	23.95	27.10	28.25	27.82
Heavy Crude Oil ($/bbl)	-	-	18.52	19.99	19.61
Combined ($/boe)	19.37	25.76	19.51	27.40	22.00

Notes:

(1) Before the deduction of royalties.

(2) Comprised of the condensate that is extracted in the field or that is otherwise sold separately from other NGL in Alberta and some condensate entrained in the NGL delivered by Kiwetinohk to fractionation facilities.

(3) 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 production by product on a pro-rata basis.

(4) Calculated by management by subtracting royalties, operating and transportation costs from sales revenue. These figures have not been adjusted for hedging gains or losses or processing and third-party income. As natural gas liquids are produced concurrently with shale gas and conventional natural gas using shared infrastructure, the netback of any individual product should not be evaluated in isolation. Netback does not have any standardized meaning and should not be used for the purposes of drawing comparisons among Kiwetinohk and other companies.

(5) During the fourth quarter of 2020, the reclassification of a Crown royalty on one well that was recorded in 2020 resulted in a refund in prior period Crown royalties of $300,000, net of the annual gas cost allowances estimate.
(6) Due to rounding, certain rows may not add exactly.

The following table indicates the average gross daily production from each of the important fields, aggregated by area, for the twelve month period ended December 31, 2020.

	Conventional Natural Gas	**Shale Gas**	**Other NGL**	**Light and Medium Crude Oil**	**Heavy Crude Oil**	**Condensate[1]**	**Total**
	(mmcf/d)	*(mmcf/d)*	*(bbl/d)*	*(bbl/d)*	*(bbl/d)*	*(bbl/d)*	*(boe/d)*
Thorhild Region	--	--	--	--	15	--	15
West Central Alberta Region	1	--	64	429	--	35	756
Total	1	--	64	429	15	35	771

Note:
(1) Comprised of the condensate that is extracted in the field or that is otherwise sold separately from other NGL in Alberta and some condensate entrained in the NGL delivered by Kiwetinohk to fractionation facilities.

2020 Distinction Reserves Report

Summary of Reserves (Forecast Prices and Costs)

Summary of Reserves
As of December 31, 2020

	Conventional Natural Gas (mmcf)		Shale Gas (mmcf)		Natural Gas Liquids (mbbls)		boe (6:1) (mboe)	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Proved								
Developed Producing	3,961	3,530	45,831	41,461	4,942	3,815	13,241	11,313
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	-	-	58,678	55,387	7,804	6,977	17,584	16,208
Total Proved	3,961	3,530	104,509	96,848	12,746	10,792	30,825	27,522
Total Probable	4,631	4,161	95,954	89,537	13,946	11,242	30,710	26,858
Total Proved plus Probable	8,592	7,690	200,462	186,385	26,692	22,034	61,534	54,380

Net Present Value of Future Net Revenue
As of December 31, 2020

	Before Income Taxes Discounted at					Unit Value Before Income Tax Discounted at 10%	
	0%	**5%**	**10%**	**15%**	**20%**		
	($ 000's)	**($ 000's)**	**($ 000's)**	**($ 000's)**	**($ 000's)**	**$/boe**	**$/mcfe**
Proved							
Developed Producing	140,701	121,706	106,304	94,206	84,655	17.34	2.89
Developed Non-Producing	-	-	-	-	-	-	-
Undeveloped	157,752	91,793	52,313	27,940	12,372	6.24	1.04
Total Proved	298,453	213,499	158,617	122,146	97,027	11.22	1.87
Probable	473,353	267,525	169,809	118,299	88,429	11.10	1.85
Total Proved plus Probable	771,807	481,024	328,426	240,445	185,456	11.16	1.86

	After Income Taxes Discounted at				
	0%	**5%**	**10%**	**15%**	**20%**
	($ 000's)	**($ 000's)**	**($ 000's)**	**($ 000's)**	**($ 000's)**
Proved					
Developed Producing	140,701	121,706	106,304	94,206	84,655
Developed Non-Producing	-	-	-	-	-
Undeveloped	157,752	91,793	52,313	27,940	12,372
Total Proved	298,453	213,499	158,617	122,146	97,027
Total Probable	366,464	211,927	138,079	98,898	75,934
Total Proved plus Probable	664,917	425,426	296,696	221,044	172,961

Total Future Net Revenue (Undiscounted)
As of December 31, 2020

	Revenue	**Royalties**	**Operating Costs**	**Capital Development Costs**	**Well Abandonment and Reclamation Costs**	**Future Net Revenue Before Income Taxes**	**Income Taxes[1]**	**Future Net Revenue After Income Taxes**
	($ 000's)	**($ 000's)**	**($ 000's)**	**($ 000's)**	**($ 000's)**	**($ 000's)**	**($ 000's)**	**($ 000's)**
Proved								
Developed Producing	397,853	63,809	179,282	1,240	12,821	140,701	-	140,701
Developed Non-Producing	-	-	-	-	-	-	-	-
Undeveloped	636,133	58,167	210,311	203,970	5,932	157,752	-	157,752
Total Proved	1,033,986	121,977	389,593	205,210	18,752	298,453	-	298,453
Total Probable	1,265,330	209,065	394,413	180,350	8,149	473,354	106,890	366,464
Total Proved plus Probable	2,299,316	331,041	784,006	385,561	26,901	771,807	106,890	664,917

Note:

(1) Future income tax expenses are estimated: (a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities; (b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income; (c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and (d) applying to the future pre-tax net cash flows relating to Distinction's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

Future Net Revenue by Product Type
As of December 31, 2020

Reserve Category	Product Type	Future Net Revenue Before Income Taxes (discounted at 10%)		
		($ 000's)	$/boe	$/mcfe
Proved Producing	Conventional Natural Gas (including by-products)	1,873	3.18	0.53
	Shale Gas (including by-products)	104,431	8.39	1.40
	TOTAL	**106,304**	**8.03**	**1.34**
Total Proved	Conventional Natural Gas (including by-products)	1,873	3.18	0.53
	Shale Gas (including by-products)	156,744	9.72	1.62
	TOTAL	**158,617**	**5.76**	**0.96**
Total Proved Plus Probable	Conventional Natural Gas (including by-products)	5,047	3.96	0.66
	Shale Gas (including by-products)	323,379	10.44	1.74
	TOTAL	**328,426**	**6.04**	**1.01**

Pricing Assumptions

This summary table identifies the benchmark reference pricing provided by GLJ, Distinction's independent qualified reserves evaluators, and used in the evaluation of Distinction's reserves in the 2020 Distinction Reserves Report.

	Light and Medium Crude Oil		NGL			Conventional Natural Gas and Shale Gas		Inflation Rate	Exchange Rate
Pricing assumptions	**West Texas Intermediate Cushing Oklahoma (US$/bbl)**	**Edmonton Par Price 40 API (Cdn$/bbl)**	**Edmonton Propane (Cdn$/bbl)**	**Edmonton Butane (Cdn$/bbl)**	**Edmonton Pentanes Plus (Cdn$/bbl)**	**U.S. Henry Hub Gas Price (US$/mmBtu)**	**AECO/NIT spot price (Cdn$/mmBtu)**	**%/year**	**US$/Cdn$**
Forecast									
2021	48.00	55.49	19.43	27.75	60.65	2.75	2.72	0.0	0.775
2022	51.50	60.78	24.31	36.47	65.36	2.80	2.67	1.0	0.765
2023	54.50	63.82	25.53	41.48	70.07	2.85	2.60	2.0	0.760
2024	57.79	68.14	27.26	44.29	74.72	2.90	2.60	2.0	0.760
2025	58.95	69.67	27.87	45.29	76.25	2.95	2.65	2.0	0.760
2026	60.13	71.22	28.49	46.30	77.80	3.01	2.71	2.0	0.760
2027	61.33	72.80	29.12	47.32	79.38	3.07	2.76	2.0	0.760
2028	62.56	74.42	29.77	48.37	81.00	3.13	2.81	2.0	0.760
2029	63.81	76.07	30.43	49.44	82.64	3.19	2.87	2.0	0.760
2030	65.09	77.59	31.03	50.43	84.30	3.25	2.92	2.0	0.760
2031+	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	+2.0%/yr	2.0	0.760

Distinction received the following weighted average prices in 2020, excluding gains and losses on financial and physical commodity price contracts.

Shale Gas ($/mcf)	Conventional Natural Gas ($/mcf)	Natural Gas Liquids ($/bbl)	Total ($/boe)
2.48	2.45	33.58	23.14

Reserves Reconciliation

Reconciliation of Gross Reserves by Product Type

	Conventional Natural Gas (mmcf)			Shale Gas (mmcf)		
	Proved	**Probable**	**Proved Plus Probable**	**Proved**	**Probable**	**Proved Plus Probable**
December 31, 2019	5,016	5,499	10,515	103,523	97,460	200,982
Extensions and Improved Recovery	-	-	-	11,630	(4,806)	6,824
Technical revisions	(85)	(650)	(735)	5,179	1,492	6,671

	Conventional Natural Gas (mmcf)			Shale Gas (mmcf)		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
Discoveries	-	-	-	-	-	-
Acquisitions	-	-	-	2,346	819	3,165
Dispositions	-	-	-	-	-	-
Economic factors	(246)	(218)	(463)	(10,751)	988	(9,763)
Production	(725)	-	(725)	(7,418)	-	(7,418)
December 31, 2020	3,961	4,631	8,592	104,509	95,954	200,462

	Natural Gas Liquids (mbbls)			boe (mboe)		
	Proved	Probable	Proved Plus Probable	Proved	Probable	Proved Plus Probable
December 31, 2019	12,005	11,102	23,107	30,095	28,262	58,356
Extensions and Improved Recovery	1,797	2,315	4,112	3,735	1,514	5,249
Technical revisions	909	77	986	1,758	217	1,975
Discoveries	-	-	-	-	-	-
Acquisitions	379	152	531	770	289	1,058
Dispositions	-	-	-	-	-	-
Economic factors	(1,264)	301	(963)	(3,097)	429	(2,668)
Production	(1,079)	-	(1,079)	(2,436)	-	(2,436)
December 31, 2020	12,746	13,946	26,692	30,825	30,710	61,534

Distinction had a disciplined capital program in 2020 in which it drilled, completed and brought 3.0 (3.0 net) horizontal Montney wells on production in the Bigstone area. Proved developed producing extensions incorporated in the 2020 Distinction Reserves Report were the result of the 3.0 (3.0 net) above-mentioned Montney wells. Undeveloped Montney drilling locations in the 2020 Distinction Reserves Report decreased by 12 gross (6.8 net) in the total proved category and by 24 gross (17.5 net) in the total proved plus probable category compared to Distinction's reserves report as at December 31, 2019. The reduction in well count is mainly due to changing the well density from 6 wells per section to 4 wells per section in liquid-rich west Bigstone. Overall, Distinction's reserves stayed flat or slightly increased across different categories while future development costs decreased resulting in a more capital efficient method of capturing the reserves. Changes in reserves due to extensions and improved recovery are due to the improvements in type curves for various areas as a result of improved completion techniques utilized by Distinction and results seen over 2020.

Increase in reserves due to acquisitions represents the working interest of a partner who chose not to participate in 3 wells from the 2020 drilling program. Changes in reserves due to economic factors occur when there is a change in the economic limit of a well because of a change in factors including commodity prices, operating costs and transportations costs compared to the previous year. These changes are determined prior to any consideration of technical revisions. Decreases in reserves due to production represent reserves that were produced from Distinction's properties during 2020.

Additional Information Relating to Reserves Data

Proved and Probable Undeveloped Reserves

The following table sets forth the volumes of proved undeveloped and probable undeveloped reserves that were first attributed to each product type in each of the most recent three financial years:

Product Type	Units	2018	2019	2020
Proved Undeveloped				
Shale gas	mmcf	26,309	9,671	9,485
Conventional Natural Gas	mmcf	-	-	-
Natural Gas Liquids	mbbl	3,722	1,325	1,365
Total	mboe	8,107	2,937	2,946
Probable Undeveloped				
Shale Gas	mmcf	41,280	11,075	-
Conventional Natural Gas	mmcf	-	-	-
Natural Gas Liquids	mbbl	5,044	1,654	2,358
Total	mboe	11,924	3,500	2,358

The future development costs are capital costs required in the future for Distinction to convert proved and probable undeveloped reserves into proved developed producing reserves. On an on-going basis Distinction typically uses its internally generated cash flow, proceeds from dispositions, available credit facilities and new equity financings, if available on favourable terms, to fund requirements for future development required to develop the proved or the proved plus probable reserves.

Development of undeveloped reserves within the 2020 Distinction Reserves Report are scheduled to deliver approximately 8,000 boe/d and 10,000 boe/d in total proved and total proved plus probable, respectively in 2022 and stay flat while the inventory lasts in each respective category. Sufficient processing capacity exists to support proved and proved plus probable undeveloped reserves coming on production. A number of other factors considered in determining the development schedule of undeveloped reserves include resource loading to address appropriate activity levels and the anticipated availability of free cash flow to fund development.

In the 2020 Distinction Reserves Report, Distinction has anticipated that approximately 40% of future development costs relating to the development of Distinction's proved undeveloped reserves will occur within two years, and all future development costs in respect of these reserves are anticipated to occur within six years. In the 2020 Distinction Reserves Report, Distinction has anticipated that approximately 22% of future development costs relating to the development of Distinction's undeveloped proved plus probable reserves will occur within two years and all future development costs in respect of these undeveloped reserves are anticipated to occur within 11 years to appropriately align with the Distinction's cash flow from development.

Significant Factors or Uncertainties

The process of evaluating reserves is inherently complex and requires significant judgments and decisions based upon a number of variable factors and assumptions, such as commodity prices, projected production from the properties, the assumed effects of regulation by government agencies and future operating costs. All of these estimates may vary from actual results. The reserve estimates contained herein are based on current production forecasts, prices and economic conditions. Estimates of the recoverable crude oil and natural gas reserves attributable to any particular group of properties, classifications of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, may vary. Distinction's actual production, revenues, taxes, development and operating expenditures with respect to its reserves may vary from such estimates and such variances could be material.

Distinction estimates the total cost of future abandonment and reclamation for its existing wells, including their associated production facilities and infrastructure, and the expected timing of the costs to be incurred in future periods. Distinction has a process for estimating these costs, which considers past experience, applicable current regulations, technology and industry standards, actual and anticipated costs, the type and depth of the well (or the nature and size of the facility), and the geographic location. Distinction expects to incur abandonment and reclamation costs on 341 (205.6 net) wells, comprising currently producing and non-producing wells. As at December 31, 2020 Distinction has estimated its share of the future abandonment and reclamation costs for its existing wells and facilities to be $42.8 million undiscounted (approximately $12.5 million discounted at 10%), of which Distinction expects to spend approximately $3.3 million undiscounted over the next three financial years. Of the undiscounted future abandonment and reclamation costs to be incurred over the life of Distinction's proved developed producing reserves, approximately $12.8 million has been deducted in estimating the future net revenue in the 2020 Distinction Reserves Report. For total proved plus probable reserves, approximately $26.9 million of undiscounted future abandonment and reclamation costs has been deducted in estimating the future net revenue in the 2020 Distinction Reserves Report, which represents Distinction's total existing estimated abandonment and reclamation costs associated with the developed reserves, plus all forecast estimates of abandonment and reclamation costs attributable to future development activity associated with the undeveloped reserves. In the 2020 Distinction Reserves Report, abandonment and reclamation costs have been included only for wells with reserves assigned. Abandonment and reclamation costs for suspended wells with no reserves assigned, service wells, gathering systems, facilities and surface land have not been included in the 2020 Distinction Reserves Report but are included in Distinction's estimate of future abandonment and reclamation costs. Distinction does not anticipate any unusually high expected development costs or operating costs in respect of its reserves.

Future Development Costs (Forecast Prices and Costs)

Period	Proved Reserves ($ 000's)	Proved Plus Probable Reserves ($ 000's)
2021	31,015	31,015
2022	50,084	55,074
2023	30,623	45,020
2024	50,339	36,337
2025	33,528	36,767
Remainder	9,621	181,347
Total for all years undiscounted	205,210	385,867
Total for all years discounted at 10% per year	160,171	251,511

On an on-going basis, Distinction typically uses its internally generated cash flow, proceeds from dispositions, available credit facilities and new equity and debt financings, if available on favourable terms, to fund requirements for future development required to develop the proved or the proved plus probable reserves. Distinction evaluates the available financing alternatives closely and has made use of all of the foregoing options depending on the given investment situation and the capital markets. Distinction expects to continue to use all financing alternatives available to continue pursuing its development strategy. The various financing alternatives have certain inherent costs which are considered in the economic evaluation of pursuing any development opportunity.

There can be no guarantee that funds will be available or that Distinction will allocate funding to develop all of the reserves attributed in the 2020 Distinction Reserves Report. Failure to develop those reserves would have a negative impact on future production and cash flow and could result in negative revisions to reserves.

The interest or other costs of external funding are not included in the reserves and future net revenue estimates set forth above and would reduce the reserves and future net revenue to some degree depending upon the available funding sources. Distinction does not anticipate that interest or other external funding costs would make further development of a property uneconomic for Distinction.

Other Oil and Gas Information

See AIF for a description of Distinction's important properties, plants, facilities and installations.

Oil and Gas Properties and Wells (All Onshore)

The following table sets forth the number and status of wells in which Distinction had a working interest as at December 31, 2020. Distinction has title to its net working interest in all wells and is not subject to any change in ownership as a consequence of any current contract or agreement.

	Producing Wells				Non-Producing Wells			
	Oil		Gas		Oil		Gas	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	3	2.3	121	94.8	15	13.6	164	76.0
British Columbia	-	-	-	-	-	-	38	18.9
	3	2.3	121	94.8	15	13.6	202	94.9

Of the 217 (108.5 net) non-producing wells, 100 (47.4 net) have been abandoned and 42 (22.1 net) have had zonal abandonments. Distinction does not have any properties to which reserves have been attributed and which are capable of producing, but which are not producing.

Properties with No Attributed Reserves

The following table sets forth Distinction's unproved land holdings as at December 31, 2020.

	Unproved	
(Acres)	**Gross**	**Net**
Alberta	89,062	46,759
British Columbia	30,108	12,237
Total	119,170	58,996

During 2021, approximately 28,450 net acres of Distinction's land is set to expire, however Distinction expects that, subject to Crown approval, approximately 65% of these lands will be continued.

None of the above properties are subject to any work commitments.

Significant Factors or Uncertainties Relevant to Properties with No Attributed Reserves

There are several economic factors and significant uncertainties that affect Distinction's anticipated development of its properties to which no reserves are attributed. Distinction will be required to make substantial capital expenditures in order to prove, exploit, develop and produce from these properties in the future. If cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to Distinction. Failure to obtain such financing on a timely basis could cause Distinction to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations on such properties. The inability of Distinction to access sufficient capital for its exploration and development purposes could have a material adverse effect on Distinction's ability to execute its business strategy to develop these prospects.

The primary economic factors that affect the development of the properties to which no reserves have been attributed are future commodity prices for oil, natural gas and NGL (and Distinction's outlook relating to such prices) and the future costs of drilling, completing, tying-in and operating wells at the time that such activities are considered. Distinction would also need to secure adequate transportation capacity on acceptable terms for its incremental future production. The primary uncertainties that affect the development of such lands are the future drilling and completion results achieved in the development activities, drilling and completion results achieved by others on lands in close proximity to these lands, and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Conversely, uncertainty as to the timing and nature of the evolution or development of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such properties.

Forward Contracts

Distinction uses risk management contracts in order to reduce its exposure to fluctuations in commodity prices. These instruments are not used for trading or speculative purposes.

All of the contracts through which Distinction has fixed the price applicable to certain of its future production outstanding as at December 31, 2020 have been disclosed in Note 6 to the audited financial statements of Distinction as at December 31, 2020 and 2019 and for each of the years in the three-year period ended December 31, 2020, as further described in the Financial Statements.

Distinction has an agreement with Alliance for full path service to deliver up to 29.7 mmcf/d of natural gas volumes until October 2025 into the Chicago gas market. In addition, Distinction has service on NGTL until March 2026. Distinction's transportation commitments with Alliance and NGTL exceed Distinction's current expected future production from its total proved reserves. Although Distinction's Montney production is currently being shipped on both the Alliance Pipeline (K3 plant) and NGTL (Bigstone gas plant), Distinction expects to ship the majority of its Bigstone Montney production on the Alliance Pipeline after an Alliance Pipeline lateral from Bigstone gas plant is reactivated in 2022. Based on this and the gas production from total proved reserves in the 2020 Distinction Reserves Report, the total cost of the excess transportation capacity on the Alliance Pipeline and NGTL is estimated to be approximately $20.6 million for the term of these services. In order to mitigate the cost of transportation service in excess of its needs, Distinction temporarily assigns the excess service to other shippers or purchases natural gas in Alberta or British Columbia for sale in Chicago. Distinction has already mitigated approximately $3.1 million in excess Alliance Pipeline transportation for 2021 by temporarily assigning approximately 17 mmcf/d until November 1, 2021.

Tax Horizon

The income taxes deducted in the calculation of future net revenue assume a scenario whereby Distinction produces all of its existing proved plus probable reserves. Under this scenario, Distinction would pay taxes in 2027.

Distinction forecasts its tax horizon assuming reinvestment of cash flow to achieve production and reserve growth. Distinction does not expect to be required to pay income taxes for the 2020 financial year. Distinction does not anticipate becoming cash taxable before 2027. This estimate will be impacted by, among other factors, production volumes, commodity prices, foreign exchange rates, operating costs, interest rates, changes in tax laws and Distinction's other business activities. Changes in these factors from estimates used by Distinction could result in Distinction paying income taxes earlier than expected.

Costs Incurred

During 2020, Distinction incurred the following costs in Canada:

	2020 ($ 000's)
Property and acquisition costs – Unproved properties	-
Property and acquisition costs – Proved properties	-
Exploration costs	-
Development costs	23,047

Exploration and Development Activities

The following table sets forth the number of completed exploratory and development wells in which Distinction participated which were drilled during the year ended December 31, 2020:

	Exploratory Wells		**Development Wells**	
	Gross	**Net**	**Gross**	**Net**
Natural gas wells	-	-	3.0	3.0
Total wells(1)	-	-	3.0	3.0

Note:
(1) Distinction did not drill any dry holes or stratigraphic test wells for the year ended December 31, 2020.

Distinction's capital program for 2020 was focused on the delineation and development of its inventory of opportunities at Bigstone in the Montney formation. Distinction expects to continue to develop and delineate the Bigstone Montney asset as part of its capital program in 2021.

Production Estimates

The following table sets forth the volume of daily gross production estimated for the year 2021 in the reserves forecast from the Distinction Reserves Report for proved, probable and proved plus probable reserves.

Proved	**Conventional Natural Gas (mcf/d)**	**Shale Gas (mcf/d)**	**Natural Gas Liquids (bbls/d)**	**Total (boe/d)**
Bigstone Montney	-	20,624	2,554	5,992
Bigstone Sweet	2,990	-	94	592
Other	10	-	-	2
Total Proved	3,000	20,624	2,648	6,585

Probable

	Conventional Natural Gas (mcf/d)	Shale Gas (mcf/d)	Natural Gas Liquids (bbls/d)	Total (boe/d)
Bigstone Montney	-	704	355	473
Bigstone Sweet	71	-	2	14
Other	-	-	-	-
Total Proved	71	704	358	487

Proved plus Probable

	Conventional Natural Gas (mcf/d)	Shale Gas (mcf/d)	Natural Gas Liquids (bbls/d)	Total (boe/d)
Bigstone Montney	-	21,329	2,909	6,464
Bigstone Sweet	3,061	-	96	606
Other	10	-	-	2
Total Proved	3,071	21,329	3,006	7,072

Production History

Distinction's 2020 average daily production, before deduction of royalties, is summarized below:

	Quarter Ended				
Average Daily Production	**March 31, 2020**	**June 30, 2020**	**September 30, 2020**	**December 31, 2020**	**Year Ended December 31, 2020**
Conventional Natural Gas (mcf/d)	2,519	2,545	2,724	3,189	2,722
Shale Gas (mcf/d)	21,082	18,352	19,076	19,502	19,525
Natural Gas Liquids (bbls/d)	2,641	3,140	3,002	3,009	2,949
Total (boe/d)	6,575	6,623	6,635	6,791	6,657

Distinction's 2020 share of average daily production, before deduction of royalties, from Bigstone Montney is summarized below:

	Quarter Ended				
Average Daily Production	**March 31, 2020**	**June 30, 2020**	**September 30, 2020**	**December 31, 2020**	**Year Ended December 31, 2020**
Shale Gas (mcf/d)	21,082	18,352	19,076	19,502	19,525
Natural Gas Liquids (bbls/d)	2,523	3,050	2,914	2,914	2,851
Total (boe/d)	6,037	6,109	6,093	6,164	6,105

Distinction's 2020 share of average daily production, before deduction of royalties, from Bigstone Sweet is summarized below:

	Quarter Ended				
Average Daily Production	**March 31, 2020**	**June 30, 2020**	**September 30, 2020**	**December 31, 2020**	**Year Ended December 31, 2020**
Conventional Natural Gas (mcf/d)	2,508	2,534	2,723	3,185	2,715
Natural Gas Liquids (bbls/d)	117	89	88	95	97
Total (boe/d)	535	511	542	626	550

Netback By Product

The following table sets forth information in respect of quarterly average net product prices received before risk management contracts, royalties paid, operating expenses and operating netbacks by product for the year ended December 31, 2020.

	Conventional Natural Gas ($/mcf)			
	Quarter Ended			
	March 31, 202	**June 30, 2020**	**September 30, 2020**	**December 31, 2020**
Average prices received	2.06	2.43	2.87	2.81
Royalties	0.81	0.08	0.05	0.04

Operating expenses[(1)]	(2.39)	(3.37)	(1.38)	(2.79)
Transportation[(1)]	(0.22)	(0.19)	(0.27)	(0.26)
Netback	0.26	(1.05)	1.27	(0.20)

	Shale Gas ($/mcf)			
	Quarter Ended			
	March 31, 202	**June 30, 2020**	**September 30, 2020**	**December 31, 2020**
Average prices received	2.40	2.08	2.40	2.90
Royalties	(0.01)	(0.16)	(0.25)	(0.27)
Operating expenses[(1)]	(2.87)	(2.27)	(2.08)	(2.48)
Transportation[(1)]	(0.83)	(0.80)	(0.79)	(0.90)
Netback	(1.31)	(1.15)	(0.72)	(0.75)

	Natural Gas Liquids ($/mcf)			
	Quarter Ended			
	March 31, 202	**June 30, 2020**	**September 30, 2020**	**December 31, 2020**
Average prices received	38.15	18.44	39.11	39.74
Royalties	(5.33)	(2.19)	(3.62)	(4.30)
Operating expenses[(1)(2)]	-	-	-	-
Transportation[(1)]	(2.90)	(3.33)	(2.44)	(2.78)
Netback	29.92	12.92	33.05	32.66

Notes:

(1) Operating expenses and transportation amount to production costs.

(2) Distinction does not allocate operating expenses to natural gas liquids as they are a by-product of conventional natural gas and shale gas.

Product Sales Revenues

The only significant products produced and sold by Distinction are conventional natural gas, shale gas and natural gas liquids. Virtually all of these products are sold on a short term basis that is a function of current market prices. None of Distinction's products are sold to non-arm's length parties.

The following table summarizes Distinction's revenues in 2020 and 2019 by product type.

Product *($ 000's)*	**2020**	**2019**
Conventional Natural Gas	2,458	1,633
Shale Gas	17,670	27,209
Natural Gas Liquids	36,246	64,040

2020 Simonette Assets Reserves Report

Summary of Reserves (Forecast Prices and Costs)

Summary of Reserves
As of December 31, 2020 — Forecast Prices and Costs

Reserves Category	Shale Gas[2]		NGL[3]	
	Gross	Net	Gross	Net
	(mmcf)	*(mmcf)*	*(mbbl)*	*(mbbl)*
Proved:				
Developed Producing	75,493.8	71,663.9	12,568.9	10,460.1
Developed Non-Producing	-	-	-	-
Undeveloped	99,870.3	94,560.9	17,946.9	16,094.1
Total Proved[1]	175,364.1	166,224.8	30,515.8	26,554.2
Total Probable	247,053.8	231,416.1	41,298.9	34,555.0
Total Proved plus Probable[1]	422,417.9	397,640.9	71,814.7	61,109.2

Notes:
(1) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "Glossary, Selected Abbreviations and Selected Conversions" in Appendix "A" to the AIF.
(2) Figures include NGL for both conventional and unconventional reservoirs, including condensate, pentane plus, propane, butane and ethane. Condensate is expected to be extracted in the field and sold separately from other NGL or sold with other NGL delivered to fractionation facilities.

Net Present Values of Future Net Revenue Before Income Taxes Discounted At (%/Year) As of December 31, 2020 Forecast Prices and Costs[1]

Reserves Category	0%	5%	10%	15%	20%	Unit Value Discounted at 10% per Year $/boe[3]
	($mm)	*($mm)*	*($mm)*	*($mm)*	*($mm)*	
Proved:						
Developed Producing	491.3	392.4	320.7	271.2	236.0	14.3
Developed Non-Producing	-	-	-	-	-	-
Undeveloped	641.5	426.3	297.7	215.5	159.6	9.34
Total Proved[2]	1,132.8	818.7	618.3	486.6	395.6	11.40
Total Probable	1,786.2	869.7	477.5	285.3	181.2	6.53
Total Proved plus Probable[2]	2,919.0	1,688.4	1,095.9	772.0	576.7	8.60

Notes:
(1) Estimates of future net revenue do not represent fair market value.
(2) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "Glossary, Selected Abbreviations and Selected Conversions" in Appendix "A" to the AIF.
(3) The unit values are based on net reserve volumes.

Net Present Values of Future Net Revenue After Income Taxes Discounted At (%/Year) As of December 31, 2020 — Forecast Prices and Costs[1]

Reserves Category	0%	5%	10%	15%	20%
	($mm)	*($mm)*	*($mm)*	*($mm)*	*($mm)*
Proved:					
Developed Producing	432.1	348.3	285.9	242.4	211.4
Developed Non-Producing	-	-	-	-	-
Undeveloped	496.3	321.7	217.6	151.5	107.0
Total Proved[2]	928.4	670.0	503.5	394.0	318.4
Total Probable	1373.2	658.4	353.0	205.0	126.1
Total Proved plus Probable[2]	2301.6	1328.4	856.4	598.9	444.6

Notes:
(1) Estimates of future net revenue do not represent fair market value.
(2) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "Glossary, Selected Abbreviations and Selected Conversions" in Appendix "A" to the AIF.

Total Future Net Revenue (Undiscounted)
As of December 31, 2020 Forecast Prices and Costs

Reserves Category	Revenue(1)	Royalties(2)	Operating Costs	Development Costs	Abandonment and Reclamation Costs(3)	Future Net Revenue Before Income Taxes(4)	Future Income Tax Expenses	Future Net Revenue After Income Taxes(4)
	($mm)	($mm)	($mm)	($mm)	($mm)	($mm)	($mm)	($mm)
Total Proved(5)	2,368.6	259.4	498.7	413.8	63.9	1,132.8	204.4	928.4
Total Proved plus Probable(5)	6,072.7	786.8	1,173.2	1,104.1	89.6	2,919.0	617.4	2301.6

Notes:
(1) Total revenue includes revenue before royalties and includes other income.
(2) Royalties include Crown, freehold and overriding royalties, mineral tax and net profit interest payments.
(3) Abandonment and reclamation costs are defined by NI 51-101 as all costs associated with the process of restoring properties that have been disturbed by oil and gas activities to a standard imposed by applicable government or regulatory authorities.
(4) Estimates of future net revenue do not represent fair market value.
(5) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserve categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained under the heading "Glossary, Selected Abbreviations and Selected Conversions" in Appendix "A" to the AIF.

Future Net Revenue by Production Group
As of December 31, 2020 Forecast Prices and Costs

Reserves Category	Product Type(1)	Future Net Revenue Before Income Tax (discounted at 10%/year)(1)(2)	Unit Value Before Income Tax (discounted at 10%/year)(2)(3)
		($mm)	($/mcf) ($/bbl)
Proved(4)	Shale Gas (Including By-products)	618.3	3.72
Proved plus Probable(4)	Shale Gas (Including By-products)	1,095.9	2.76

Notes:
(1) The before tax future net revenue discounted at 10% for shale gas includes all by-product revenue streams from ethane, propane, butane and pentanes plus.
(2) Estimates of future net revenue do not represent fair market value. May not sum due to rounding.
(3) Unit values are based on net reserves.
(4) These figures are derived from volumes that are arithmetic sums of multiple estimates of reserves categories or sub-categories, which statistical principles indicate may be misleading as to volumes that may actually be recovered. Readers should review the estimates of individual classes of reserves and appreciate the differing probabilities of recovery associated with each class as explained above under the heading "Glossary, Selected Abbreviations and Selected Conversions" in Appendix "A" to the AIF.

Pricing Assumptions

The forecast of prices, inflation and exchange rates provided in the table below were computed using the average of forecasts prepared by McDaniel, GLJ and Sproule Associates Limited, effective January 1, 2021. The forecasts are available on the websites of McDaniel, GLJ and Sproule Associates Limited.

Summary of Pricing and Inflation Rate Assumptions
As of January 1, 2021 Forecast Prices and Costs

	Natural Gas		NGLs(1)				Crude Oil				
Year	AECO Gas Price	U.S. Henry Hub Gas Price US$	Edmonton Ethane	Edmonton Propane	Edmonton Butane	Edmonton Cond. & Natural Gasolines	WTI Cushing Oklahoma	Edmonton Par Price 40° API	Hardisty Heavy 12° API	Inflation Rate(2)	Exchange Rate(3)
	($/mmBtu)	(US$/mmBtu)	($/bbl)	($/bbl)	($/bbl)	($/bbl)	(US$/bbl)	($/bbl)	($/bbl)	%/Year	(US$/$)
2021	2.78	2.83	8.91	18.18	26.36	59.24	47.17	55.76	39.87	0.0	0.768
2022	2.70	2.87	8.65	21.91	32.85	63.19	50.17	59.89	43.20	1.3	0.765
2023	2.61	2.90	8.35	24.57	39.20	67.34	53.17	63.48	46.86	2.0	0.763
2024	2.65	2.96	8.46	25.47	40.65	69.77	54.97	65.76	48.67	2.0	0.763
2025	2.70	3.02	8.63	26.00	41.50	71.18	56.07	67.13	49.65	2.0	0.763
2026	2.76	3.08	8.81	26.54	42.36	72.61	57.19	68.53	50.65	2.0	0.763
Thereafter		Escalated at 2.0%/yr								2.0	0.763

Notes:
(1) Inflation rates for forecasting prices and costs.
(2) Exchange rates used to generate the benchmark reference prices in this table.

Reserves Reconciliation

The 2020 Simonette Assets Reserves Report does not include information that would allow the Company to prepare a reserves reconciliation and the Company does not have access to the information from which the 2020 Simonette Assets Reserves Report was prepared.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty to be recoverable where significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. Probable undeveloped reserves are those additional reserves that are less certain to be recovered than proved reserves where significant expenditure is required to render them capable of production. The 2020 Simonette Assets Reserves Report contains proved and probable undeveloped reserves that have been estimated in accordance with the procedures and standards contained in the COGEH.

As of December 31, 2020, undeveloped reserves represented approximately 58% of total gross proved reserves and approximately 24% of gross proved plus probable reserves. The timing of proved undeveloped reserve and probable undeveloped reserve development beyond two years is due to the large land base, a well-defined drilling inventory supported by offset production, Kiwetinohk's scheduled pace of commercial development, and the timing of planned and current infrastructure construction.

The pace of development of these reserves is influenced by several factors including, but not limited to, the outcomes of drilling and reservoir evaluations, changes in commodity pricing, changes in capital allocations, changing technical conditions, access to markets, regulatory changes and impact of future acquisitions and dispositions. These reserves are reviewed and development plans are revised accordingly as new information becomes available.

The 2020 Simonette Assets Reserves Report does not include information that would allow the Company to prepare a reconciliation of gross proved undeveloped reserves and the gross probable undeveloped reserves and the Company does not have access to the information from which the 2020 Simonette Assets Reserves Report was prepared.

Significant Factors or Uncertainties Affecting Reserves Data

The process of evaluating reserves is inherently complex. It requires significant judgment and decision-making on the basis of the available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance become available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on production expectations, forecast prices and economic conditions as at December 31, 2020. Factors and assumptions that affect these reserves estimates include, among other things: (a) historical production in the area compared with production rates from analogous producing areas; (b) initial production rates; (c) production decline rates; (d) ultimate recovery of reserves; (e) success of future development activities; (f) marketability of production; (g) effects of government regulations; and (h) government levies imposed over the life of the reserves.

As circumstances change and additional data become available, reserves estimates may also change. Estimates are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well and reservoir performance, geological conditions, production, prices, changes in corporate strategy, economic conditions and governmental restrictions. These revisions can be either positive or negative.

In connection with its operations, Kiwetinohk will incur abandonment, dismantling, reclamation and remediation costs for surface leases, wells, facilities and pipelines. Kiwetinohk budgets for and recognizes as a liability the estimated present value of the future decommissioning liabilities associated with its oil and gas assets. Kiwetinohk uses guidance from the AER and consultation with an independent third-party engineering firm to validate the estimates of such liabilities. Approximately 80% of Kiwetinohk's decommissioning liabilities on its financial statements are associated with active properties that have production and attributable reserves. There is approximately $1.8 million of inactive abandonment and reclamation costs associated with inactive wells or facilities where there is no active operations or attributed reserves. Kiwetinohk is currently working on an abandonment program to proactively manage and reduce the inactive decommissioning liabilities over the next three to five years. There are no unusually significant abandonment and reclamation costs associated with its reserves properties or to properties with no attributed reserves.

The evaluated oil and gas properties of the Simonette Assets have no material extraordinary risks or uncertainties beyond those that are inherent in unconventional oil and gas exploration and production operations. See "*Risk Factors*" in the AIF.

Future Development Costs

The following table sets forth development costs deducted in the estimation of future net revenue attributable to the Simonette Assets in the reserves categories noted below.

	Annual Development Costs	
Year	**Total Proved**	**Total Proved plus Probable**
	($mm)	*($mm)*
2021	60.3	60.3
2022	90.9	90.9
2023	75.0	75.0
2024	98.0	98.0
2025	68.6	115.0
Thereafter	21.5	664.9
Total (Undiscounted)	413.8	1104.1
Total (Discounted at 10%)	320.9	684.3

Kiwetinohk expects to fund the development costs of its reserves through current working capital, cash flow from operations, borrowings under its credit facilities and by accessing the global capital markets. There can be no guarantee that funds will be available or that the Board will allocate funding to develop all of the reserves attributed in the 2020 Simonette Assets Reserves Report. Failure to develop those reserves could have a negative impact on Kiwetinohk's future net revenue relative to the estimates provided herein.

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

The future development costs set forth above do not include costs associated with abandonment and reclamation obligations.

Other Oil and Natural Gas Information

Oil and Natural Gas Wells

The following table sets forth the number and status of wells in which Simonette Assets had a working interest as at December 31, 2020, all of which are located in Alberta.

Natural Gas Wells				**Oil Wells**			
Producing[(1)]		**Non-Producing**[(1)]		**Producing**[(1)]		**Non-Producing**[(1)]	
Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
80	80	0	1	8	8	0	0

Note:

(1) Producing wells are wells that are actively producing as of the respective date. Non-producing wells are wells that are not actively producing, and for which a reclamation certificate has not been granted, as of the respective date.

Properties with No Attributed Reserves

The 2020 Simonette Assets Reserves Report does not assign reserves to specific acreage and the Company does not have access to the information from which the 2020 Simonette Assets Reserves Report was prepared.

Kiwetinohk continually reviews the economic viability and ranking of unproved properties on the basis of product pricing, capital availability, the anticipated cost to re-acquire, and the allocation and level of infrastructure development in any specific area. From this process, some properties are scheduled for economic development activities while others are temporarily held inactive, sold, swapped or allowed to expire. There is no guarantee that commercial reserves will be discovered or developed on these properties.

During 2021 subsequent to the acquisition of the Simonette Assets, approximately 48,160 net acres of the Simonette Assets have expired or are likely to expire. The Company does not expect that any significant amount of these lands will be continued.

None of these properties are subject to any work commitments.

When determining acreage, totals are adjusted to remove overlapping acreage under applicable petroleum and natural gas agreements.

Significant Factors or Uncertainties Relevant to Properties with no Attributed Reserves

There are several economic factors and significant uncertainties that affect Kiwetinohk's anticipated development of its properties to which no reserves are attributed. Kiwetinohk will be required to make substantial capital expenditures in order to prove, exploit, develop and produce oil, natural gas and NGL from these properties in the future. If cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to Kiwetinohk. Failure to obtain such financing on a timely basis could cause Kiwetinohk to forfeit its interest in certain properties, miss certain opportunities and reduce or terminate its operations on such properties. The inability of Kiwetinohk to access sufficient capital for its exploration and development purposes could have a material adverse effect on Kiwetinohk's ability to execute its business strategy to develop these prospects. See "*Risk Factors*" in the AIF. The primary economic factors that affect the development of the properties to which no reserves have been attributed are future commodity prices for oil, natural gas and NGL (and Kiwetinohk's outlook relating to such prices) and the future costs of drilling, completing, tying-in and operating wells at the time that such activities are considered. Kiwetinohk would also need to secure adequate transportation capacity on acceptable terms for its incremental future production. The primary uncertainties that affect the development of such lands are the future drilling and completion results achieved in the development activities, drilling and completion results achieved by others on lands in close proximity to these lands, and future changes to applicable regulatory or royalty regimes that affect timing or economics of proposed development activities. All of these uncertainties have the potential to delay the development of such lands. Conversely, uncertainty as to the timing and nature of the evolution or development of better exploration, drilling, completion and production technologies have the potential to accelerate development activities and enhance the economics relating to such properties.

McDaniel has estimated undiscounted and inflated abandonment and reclamation costs of approximately $0.15 million in respect of its evaluation of the Simonette Asset's proved plus probable reserves. Kiwetinohk does not expect that these abandonment or reclamation costs will materially affect the anticipated development or production activities on its properties with no attributed reserves.

Forward Contracts and Transportation Obligations

Kiwetinohk uses risk management contracts in order to reduce its exposure to fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. All of the contracts through which Kiwetinohk has fixed the price of future production, outstanding as at December 31, 2020, as further described in the Financial Statements.

As part of normal business operations, Kiwetinohk enters into long-term commitments to transport and fractionate (as applicable) its oil, natural gas, condensate and other NGL production volumes. Transportation and fractionation of NGL are interdependent. The commitments are entered to secure capacity to market and sell these commodities, considering future growth plans, capacity constraints within the area and expectations for future transportation and fractionation costs. Accordingly, capacity deficits may arise when comparing future reserve production estimates against such commitments. See "*Commitments*" in the management's discussion and analysis of operations, financial position and outlook of Kiwetinohk for the three and six months ended June 30, 2021 and 2020, as further described in the Financial Statements.

The shortfall relative to the commitments described above reflects the future production of Kiwetinohk's proved reserves development plan. Kiwetinohk believes that holding these transportation commitments is an asset and envisions a number of ways in which the indicated impacts can be partially or wholly reduced. For example, Kiwetinohk is able to accelerate development at its discretion, depending on, among other factors, financial capacity related to prevailing commodity prices and existing field processing capacity, and Kiwetinohk mitigates a portion of its unused take-or-pay capacity through marketing transactions. Kiwetinohk is of the view that holding transportation commitments sized only to Proved Reserves would be insufficient relative to the production potential of its assets. Kiwetinohk believes that the transportation commitments are more accurately sized to the potential recognized within proved plus probable reserves.

Tax Horizon

As at December 31, 2020, Kiwetinohk had accumulated tax pools and loss carry forwards of approximately $108 million, including approximately $49 million in tax pools available for immediate deduction against any future taxable income. Based on anticipated capital investment, which augments the tax pools, Kiwetinohk does not expect to pay material Canadian income tax for approximately three years (based on McDaniel's forecast, see "*Pricing Assumptions*"). This estimate will be impacted by, among other factors, production volumes, commodity prices, foreign exchange rates, operating costs, interest rates, changes in tax laws and Kiwetinohk's other business activities. Changes in these factors from estimates used by Kiwetinohk could result in Kiwetinohk paying income taxes earlier than expected.

Costs Incurred

The 2020 Simonette Assets Reserves Report does not include information that would allow the Company to prepare a summary of the costs incurred in respect of the Simonette Assets for the twelve months ended December 31, 2020 and the Company does not have access to the information from which the 2020 Simonette Assets Reserves Report was prepared.

Exploration and Development Activities

The following table sets forth the gross and net exploratory and development wells involving the Simonette Assets during the 12 months ended December 31, 2020 (based on rig release date).

	Development		**Exploratory**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Natural Gas	80	80	-	-	80	80
Oil	8	8	-	-	8	8
Service	-	-	-	-	-	-
Stratigraphic Test	-	-	-	-	-	-
Dry	1	1	-	-	1	1
			-	-		
Total	89	89	-	-	89	89

Production Estimates

The following table sets out for each product type the gross volume (before royalties) of working interest production estimated for the year ending December 31, 2021 in the estimates contained in the 2020 Simonette Assets Reserves Report for gross Proved reserves and gross Probable reserves. Actual results may differ significantly from the information below. See "*Forward-Looking Statements and Market Data*" and "*Risk Factors*" in the AIF.

Production Estimate For The
Year Ending December 31, 2021

Reserve Category	Shale Gas	NGL[(1)]	Total
	(mmcf)	*(mbbl)*	*(mboe)*
Proved	13,591.1	2,340.2	4,605.2
Probable	244.3	53.9	94.6
Total Proved plus Probable	13,835.4	2,394.1	4,700.0

Notes:
(1) Figures include NGL for both conventional and unconventional reservoirs, including pentanes plus, propane, butane and ethane. Other NGL (propane, butane and ethane) are expected to be extracted in the field by Kiwetinohk.

Production History

The 2020 Simonette Assets Reserves Report does not include information that would allow the Company to prepare a summary of the production history in respect of the Simonette Assets for the twelve months ended December 31, 2020 and the Company does not have access to the information from which the 2020 Simonette Assets Reserves Report was prepared.

The following table indicates the average gross daily production from each of the important fields, aggregated by area, for the twelve month period ended December 31, 2020.

APPENDIX "G"

Form 51-101F2 – Report on Reserves Data by
<u>Independent Qualified Reserves Evaluator or Auditor</u>

Please see attached.

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Kiwetinohk Resources Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at July 1, 2021. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at July 1, 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 shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended July 1, 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 or Auditor Effective	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – CDN M$)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	July 1, 2021	Western Alberta	-	**1,579,169.9**	-	**1,579,169.9**

6. In our opinion, the reserves data 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:

McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, July 21, 2021.

(signed) "Brian R. Hamm"

Brian R. Hamm, P. Eng.
President & CEO

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Kiwetinohk Resources Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, 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 shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2020, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor Effective	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – CDN M$)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	Dec. 31, 2020	Western Alberta	-	**305,247.1**	-	**305,247.1**

6. In our opinion, the reserves data 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:

McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, July 21 2021.

(signed) "Brian R. Hamm"

Brian R. Hamm, P. Eng.
President & CEO

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Distinction Energy Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, 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 shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2020, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
			Audited	Evaluated	Reviewed	Total
GLJ Ltd.	Dec. 31, 2020	Canada	-	328,426	-	**328,426**

6. In our opinion, the reserves data 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, March 5, 2021

"Originally Signed by"
Chad P. Lemke, P. Eng.
Executive Vice President & COO

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Kiwetinohk Energy Corp. (the "Company"):

1. We have evaluated the reserves data in respect of certain assets in the Simonette and other areas of northwest Alberta, acquired by the Company on April 28, 2021, (the "Simonette Assets") with an effective reference date of December 31, 2020. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2020, 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 shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Simonette Assets evaluated for the year ended December 31, 2020, and identifies the respective portions thereof that we have evaluated and reported on to the Company's board of directors:

Independent Qualified Reserves Evaluator or Auditor Effective	Effective Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future Net Revenue (before income taxes, 10% discount rate – M$)			
			Audited	Evaluated	Reviewed	Total
McDaniel & Associates Consultants Ltd.	December 31, 2020	Western Alberta		1,095,865		1,095,865

6. In our opinion, the reserves data 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:

McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, January 21, 2021.

(signed) "Brian R. Hamm"

Brian R. Hamm, Peng.
President & CEO

APPENDIX "H"

Form 51-101F3 – Report of Management and Directors on Oil and Gas Disclosure

Please see attached.

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Kiwetinohk Energy Corp. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data as at July 1, 2021.

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

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

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

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

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

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data 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 judgements regarding future events, actual results will vary and the variations may be material.

(signed) "Patrick Carlson"
Patrick Carlson
Chief Executive Officer

(signed) "Jakub Brogowski"
Jakub Brogowski
Chief Financial Officer

(signed) "Kaush Rakhit"
Kaush Rakhit
Director

(signed) "Nancy Lever"
Nancy Lever
Director

November 23, 2021

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Kiwetinohk Energy Corp. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data as at December 31, 2020.

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

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

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

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

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

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data 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 judgements regarding future events, actual results will vary and the variations may be material.

(signed) "Patrick Carlson"	*(signed) "Jakub Brogowski"*
Patrick Carlson	**Jakub Brogowski**
Chief Executive Officer	Chief Financial Officer
(signed) "Kaush Rakhit"	*(signed) "Nancy Lever"*
Kaush Rakhit	**Nancy Lever**
Director	Director

November 23, 2021

FORM 51-101F3

**REPORT OF MANAGEMENT AND DIRECTORS
ON RESERVES DATA AND OTHER INFORMATION**

Management of Kiwetinohk Energy Corp. (the "**Corporation**") is responsible for the preparation and disclosure of information with respect to the Corporation's oil and 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, 2020, estimated using forecast prices and costs.

An independent qualified reserves evaluator has evaluated the Corporation's amalgamation predecessor, Distinction Energy Corp. ("**DEC**"), reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

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

(a) reviewed DEC'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 of the Corporation has reviewed DEC's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board of Directors has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing information detailing DEC's oil and gas activities;

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

(c) the content and filing of this report.

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

(signed) "Patrick Carlson"
Patrick Carlson
Chief Executive Officer

(signed) "Jakub Brogowski"
Jakub Brogowski
Chief Financial Officer

(signed) "Kaush Rakhit"
Kaush Rakhit
Director

(signed) "Nancy Lever"
Nancy Lever
Director

November 23, 2021

FORM 51-101F3

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Kiwetinohk Energy Corp. (the "**Company**") is responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data as at December 31, 2020 in respect of certain assets in the Simonette and other areas of northwest Alberta now owned by the Company (the "**Simonette Assets**").

An independent qualified reserves evaluator has evaluated and reviewed the Simonette Assets' reserves data. The report of the independent qualified reserves evaluator will be filed with securities regulatory authorities concurrently with this report.

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

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

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

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

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved:

a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data 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 judgements regarding future events, actual results will vary and the variations may be material.

(signed) "Patrick Carlson"
Patrick Carlson
Chief Executive Officer

(signed) "Jakub Brogowski"
Jakub Brogowski
Chief Financial Officer

(signed) "Kaush Rakhit"
Kaush Rakhit
Director

(signed) "Nancy Lever"
Nancy Lever
Director

November 23, 2021