**Annual Information Form**

For the year ended December 31, 2022

**March 7, 2023**

**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.

**The Company's integrated energy transition business is in its early stage of development and the Company has no history of operating such business. None of the Company's power projects have reached a final investment decision, full regulatory approval or internal or external funding. Furthermore, none of the Company's carbon capture 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 as at December 31, 2022.

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 | | |
|---|---|---|---|
| | **2022** | **2021** | **2020** |
| High for the period | $ 0.8031 | $ 0.8306 | $ 0.7863 |
| Low for the period | $ 0.7217 | $ 0.7727 | $ 0.6898 |
| End of the period | $ 0.7383 | $ 0.7888 | $ 0.7854 |
| Average for the period(1) | $ 0.7692 | $ 0.7980 | $ 0.7461 |

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

The daily average exchange rate for one Canadian dollar, expressed in U.S. dollars on March 7, 2023, based on the published rate of the Bank of Canada, was $1.00 = US$0.7290.

# 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 power generation projects and expectations with respect to future opportunities for other renewable energy projects;
- the Company's ability to achieve its near to medium term objectives, including but not limited to: building power generation projects that capture solar 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 natural gas combined cycle ("**NGCC**") plants; advancing the Company's two carbon sequestration hubs for storing carbon dioxide ("**$CO_2$**") 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*");

- the Company's ability to secure the appropriate regulatory approvals for its power generation projects;

- the Company's ability to successfully and profitably deploy carbon capture technology on its Firm Renewable power plants;

- the importance of traditional fuels such as natural gas during the energy transition;

- the need to reduce and ultimately eliminate the "green premium" (lower carbon technologies are generally more expensive than their fossil fuel counterparts) associated with renewable power generation;

- the benefits of the Company's owned excess surface infrastructure capacity;

- 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 and other market prices and costs;

- the nature, timing and development of the Company's capital projects, including in respect of FID and regulatory approvals and the expected financial performance of such projects following completion of the development and the commencement of operations, as applicable;

- 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, including the benefits of using the Company's owned natural gas for natural gas-fired power generation;
- expectations regarding water use regulations and requirements in light of climate change, community and industrial growth;
- expectations regarding access of oil and gas leases in light of caribou range planning;
- Expectations regarding clean electricity, clean energy and greenhouse gas regulations and / or voluntary offsets and markets;
- 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;
- access to third party processing for sweet and sour natural gas processing;
- 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;
- industry demands for low-cost, low-emissions, reliable and dispatchable power generation;
- 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;
- the performance of wells;
- 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;
- the market shift toward CCUS with fossil fuel-fired power and a general shift away from coal toward natural gas use in power generation;
- 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 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 impact of competition on the Company;
- the Company’s ability to deal with climate change and seasonality issues;
- the Company’s ability to access fresh water for operations;
- 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;
- the ability to access lands by road;
- the ability to maintain government leases;
- the ability to obtain or maintain insurance coverage; 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;
- variability of natural gas, oil and electricity prices;
- the ability of the Company to achieve its investment and development objectives;
- the ability of the Company to successfully execute its energy transition strategy;
- 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;
- global economic and financial conditions;
- inflation and supply chain issues;
- capital market conditions;

- licenses and permits;
- government regulations;
- health, safety and environmental risks;
- competition in the crude oil and natural gas industry;
- greenhouse gas emissions regulations, carbon taxes and environmental compliance costs;
- regulatory and voluntary emissions offset regulations and markets;
- coronavirus, variants or derivations of it ("**COVID-19**") and other pandemics;
- 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 board of directors of the Company (the **"Board**" or the **"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

### Kiwetinohk Overview

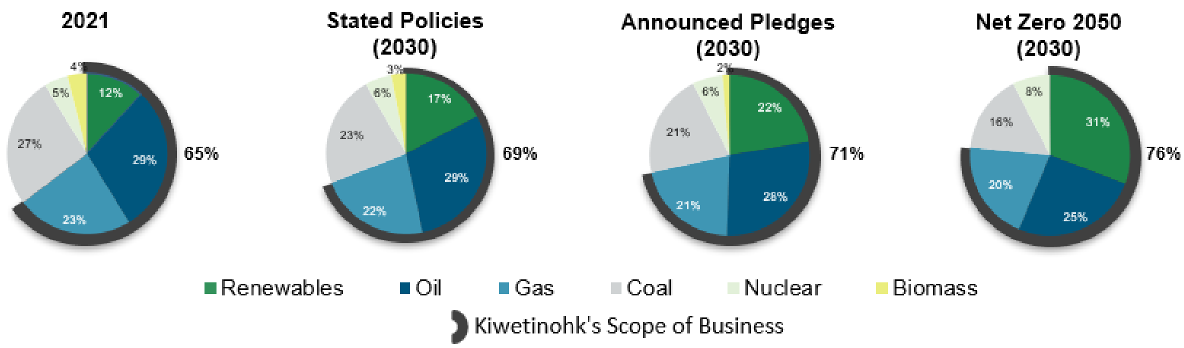
Kiwetinohk's mission is to build a profitable energy transition business providing clean, reliable, dispatchable, affordable energy. Kiwetinohk develops and produces natural gas and related products and is in the process of developing renewable power, natural gas-fired power, carbon capture and hydrogen clean energy projects as described further in this AIF.

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

Under each of its three most recent 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, as illustrated below, based on the IEA's future projections, use of traditional carbon-intensive fuels such as coal is expected to moderate, 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, natural gas-fired power generation is expected to retain a significant share of demand and backstop intermittent renewable power generation to help 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 76% of total primary energy demand by 2030[1].

[1] International Energy Agency (2022), World Energy Outlook 2022, International Energy Agency. Licence: Creative Commons Attribution CC BY-NC-SA 4.0. Charts Based on data from International Energy Agency (2022), as modified by Kiwetinohk Energy Corp.

**Estimated Share of World Energy Demand under IEA Scenarios Referenced Above**




The IEA projections are consistent with Kiwetinohk's view that energy solutions must address four customer needs: reliable, dispatchable, affordable and clean (low emission) energy. As the IEA projections indicate, complete exclusion of hydrocarbons, especially natural gas, is not currently 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 consumer energy 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, feasible 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 an energy 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 yet meet reasonable performance specifications for widespread adoption. Kiwetinohk believes that the Alberta energy market's best supply-side response to the climate change challenge is to:

1. build solar renewable power,

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

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

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

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

To Kiwetinohk, the energy transition involves transforming todays 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 methane and $CO_2$ have a long-life expectancy in the earths 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.

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, which 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 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 introducing subsidies for CCUS which may create opportunities to 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, 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 liquids, 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**

To ensure the continued availability and supply of affordable energy supplies during the energy transition, the Company expects that traditional fuels like natural gas will play an important role both for power generation and heating in certain regions, as well as for the production of hydrogen. Many are now coming to this conclusion after observing experiences of other jurisdictions navigating the energy transition. Observing the success and challenges experienced in other jurisdictions can 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.

The energy transition will require a significant amount of investment. In addition, lower carbon technologies are generally more expensive than their fossil fuel counterparts, which is often termed as the "green premium" required to deliver an equivalent form and amount of cleaner energy. Kiwetinohk believes that, in order to enable a transition that can be afforded and accepted by society, the green premium for new energy technologies will have to be reduced and eventually eliminated. The clear constraint in the adoption of renewable power generation sources today is the variability of the power generated by wind and solar as well as the lack of utility scale, long duration battery storage that can back-up the intermittency. Furthermore, lower capacity factors of renewable power sources and their significant capital costs means fixed costs are amortized over lower power volumes during the project life resulting in higher prices. Traditional levelized cost of electricity measures also do not incorporate the significant costs associated with backing-up power and grid support services that will be required as renewable generation capacity increases[2].

Kiwetinohk believes renewables alone will not be sufficient to supply low carbon energy and natural gas power generation is a necessary element of an energy transition away from traditional, carbon intensive methods of power generation. Replacing coal-fired with natural gas-fired power generation can help to immediately reduce carbon emissions while providing back-up for maximum deployment of renewable power. With the addition of commercial carbon capture technologies, natural gas-fired power may become an increasingly cleaner source of reliable and dispatchable power.

**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 is 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 power grid supply. The Company plans to pursue a business model that will allow it to participate in the expected 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 of Kiwetinohk's Business – Upstream Properties Description*" herein). The upstream assets also provide a foundational base for the Company to pursue energy transition opportunities.

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[2] Renewable Constraints – The Energy Transition – A Realistic Look at the Path Forward (January 10, 2022) online:. *Pickering Energy Partners Investments and SailingStone Capital Partners LLC* <https://sailingstonecapital.com/pdf/Whitepaper-Renewable_Constraints.pdf>.

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

The table 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*".<br><br>Monitoring market for opportunities to grow upstream production. |
| Solar photovoltaic power generation | Development continues on three solar projects with an expected 920 MW of total capacity. The Company obtained AUC power plant approval in September 2022 on its largest solar project, the 400 MW Homestead Solar project, and submitted an AUC power plant application for the 350 MW Granum Solar project. The Company acquired an early-stage development solar project with an expected 170 MW capacity and the potential for a further expected 130 MW expansion (Phoenix Solar) in May 2022. Applications in the Alberta Electrical System Operator ("**AESO**") approval process[3] have been advanced to Stage 3 for Homestead Solar and Phoenix Solar, and Stage 2 for Granum Solar. Options to lease land have been secured for the solar projects<br><br>Continuing to evaluate development, land and transmission connection alternatives suited to solar power development for additional projects. |
| Natural gas-fired power generation (*Firm Renewable** configuration)<br><br>*The term "*Firm Renewable*" is a Kiwetinohk-originated term that describes efficient, flexible-output, fast-responding, gas-fired, reciprocating, internal combustion 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". | Kiwetinohk obtained AUC power plant approval in August 2022, and Environmental Protection and Enhancement Act (EPEA) industrial approval in December 2022 for the 101 MW Opal Firm Renewable project. The project has been advanced to AESO Stage 3.<br><br>Front end engineering and design ("**FEED**") is complete and preliminary detailed engineering has been advanced for this fast-responding, flexible-output, gas-fired power generation project, which is expected to use 9 reciprocating, internal combustion engines that each deliver 11.237 MW of capacity.<br><br>Pre-FEED evaluation and investigation is underway on several technologies for the addition of a pilot scale – 1/9 total capacity – carbon capture project to be added to this power plant . |

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

| | |
|---|---|
| | Kiwetinohk has also advanced development of a second Firm Renewable power project, an expected 124 MW power plant using the same technology including 11 gas-fired, reciprocating, internal combustion engines. The project has been advanced to AESO Stage 2. |
| Natural gas-fired power generation (natural gas combined cycle configuration) | Kiwetinohk has advanced development on two NGCC power plants including pre-FEED evaluation, environmental studies and preparation for regulatory applications. One NGCC project has been advanced to AESO Stage 3, and the other, AESO Stage 2. The NGCC projects are in attractive locations with favorable access to electrical transmission, grid capacity, gas transportation and sequestration hubs. Pre-FEED evaluation has been completed on the power generation facility and carbon capture segments for both projects. Land access has been secured for one project, and is at an advanced stage for the second project. |
| CCUS | The Government of Alberta has awarded Kiwetinohk the right to advance planning on two carbon sequestration hubs located next to two of its natural gas-fired power generation projects, Opal Firm Renewable and NGCC 2, in addition to other possible third party sources of $CO_2$.<br><br>The Company aspires to add CCUS to its expected gas-fired power generation, as technology and economics allow, and will evaluate each gas-fired plant on a case-by-case basis.<br><br>Kiwetinohk has completed pre-FEED evaluation for commercially proven, carbon capture technology applicable to its two NGCC power plants. The Company has also completed a pre-FEED study as well as an evaluation of various carbon capture technologies for the Opal *Firm Renewable* project. Kiwetinohk is presently evaluating adding a CCUS demonstration project to the Opal *Firm Renewable* project. If advanced to completion, this project, as currently conceived, will evaluate a new $CO_2$ solvent that the Company believes may have superior properties to commercially proven solvents.<br><br>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. |
| Hydrogen production | The Company is evaluating hydrogen projects including potential joint ventures. |
| Wind turbine power generation | The Company is evaluating locations for greenfield projects as well as early to mid stage projects currently in the approval process. |
| Batteries | The Company is evaluating various battery and other storage technologies to support renewables and grid stability in the energy transition. |

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 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 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 solar and wind 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 Government of Alberta has awarded Kiwetinohk the right to advance planning on two carbon sequestration hubs located next to its natural gas-fired power generation projects in addition to other possible third party sources of $CO_2$. 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. The Company continues to monitor the regulatory and fiscal regime and how they may encourage development including applicable royalties, taxes, and government subsidies.

**Mid to Long-Term Objectives**

In the mid to long-term, Kiwetinohk aspires 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.

Longer 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,
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.

Kiwetinohk expects to nimbly transition as the market conditions transition. Kiwetinohk intends to choose its path in the future by selecting energy transition activities that it can do in a differentiated way. It’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 potential 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, stock market 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 2023 and are 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?**

***High-Quality Natural Gas, and Liquids Rich Natural Gas***

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's focus has been the natural gas prone land positions in the Fox Creek region of northwest Alberta.

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 has advanced development and acquired land options for its early to mid-stage renewables and gas-fired projects, and continues to evaluate favorable locations for potential future renewable and power generation projects. Kiwetinohk screens potential projects and their locations based on various considerations, including the following:

- Solar power
  - good access to 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, supportive stakeholders and good constructability
  - positive stakeholder engagement

- Gas-Fired Projects (Both *Firm Renewable* & NGCC)
  - good access to 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
    - geologic formations suited to permanent sequestration of $CO_2$
    - oil pools suited to $CO_2$ EOR
  - 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 with embedded material operating leverage from owned excess surface infrastructure capacity that can drive cash costs lower, at the same time allowing for material production growth. 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, including:

- 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.

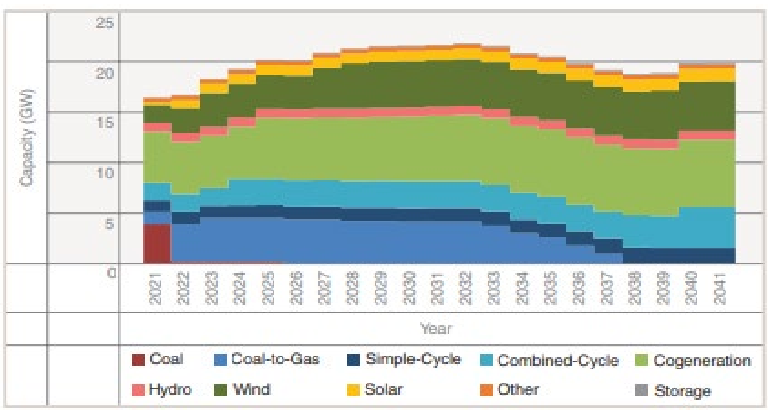
The Company believes that Alberta's deregulated power market facilitates new entrants and promotes competition. The Province has very modest import/export capacity for electricity. This simplifies forecasting future market conditions most often to supply and demand developments solely within the Province. 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[4]) 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[5]:

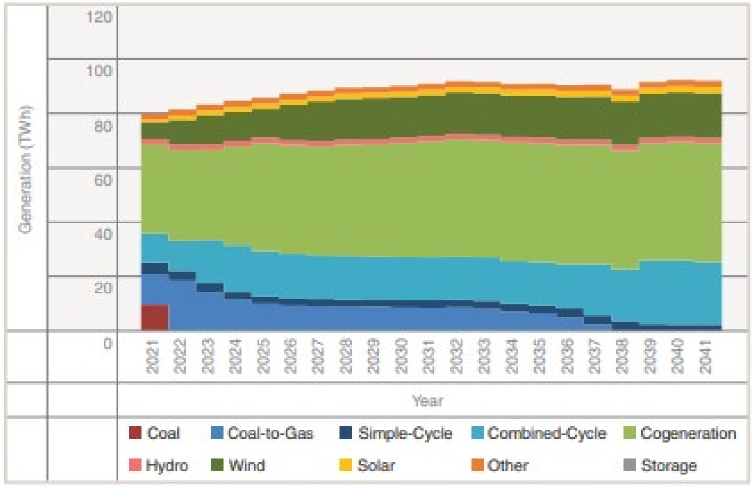
**Reference Case: Capacity by Fuel Type**




[4] "Update to the Pan-Canadian Approach to Carbon Pollution Pricing 2023-2030" (August 5, 2021) online: *Government of Canada* <https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/carbon-pollution-pricing-federal-benchmark-information/federal-benchmark-2023-2030.html>

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

**Reference Case: Alberta Generation** [6]




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.

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

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

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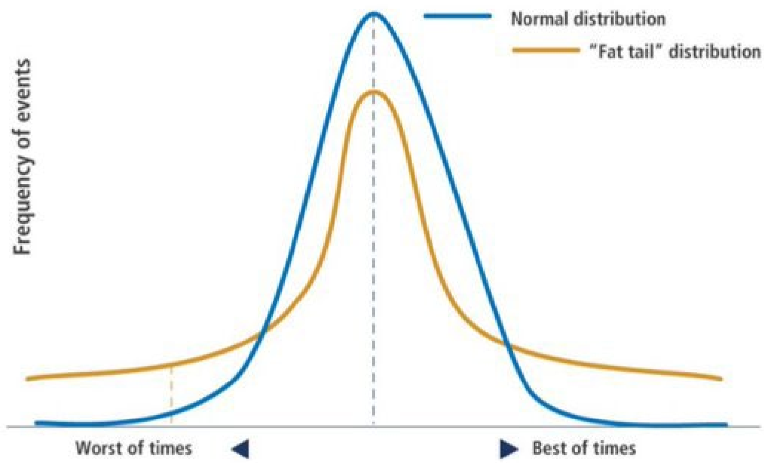
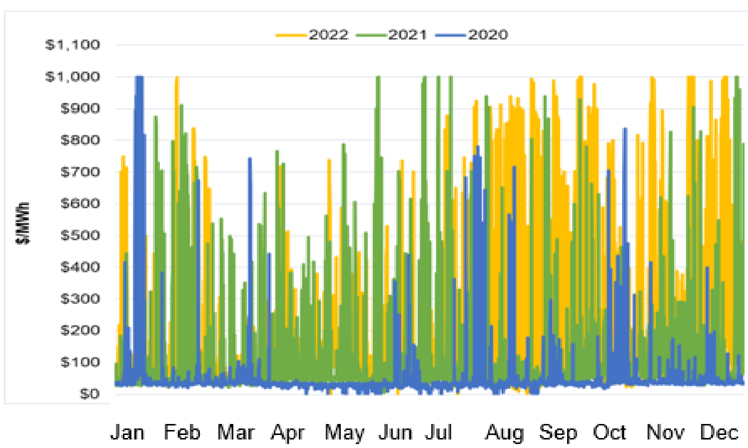
[6] "AESO 2021 Long Term Outlook" (June 2021), online: *Alberta Electric System Operator* <https://www.aeso.ca/assets/Uploads/grid/lto/2021-Long-term-Outlook.pdf>.




The above graphic depicts the expected trend in power market behavior expected by the Company. 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, dispatchable *Firm Renewable* gas-fired power generation and baseload NGCC and potentially, wind.

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. Finally, Kiwetinohk expects to be advantaged on its cost of gas for its natural gas-fired power projects given its expectation that full cycle development costs for owned gas supply will be at a material discount to the “retail price” of natural gas that non-integrated gas-fired power producers must pay. 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 clean 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 renewable 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 Directive*

Kiwetinohk is committed to maintaining high standards of corporate governance and to embedding a corporate culture centered around its founding stakeholder principles, and has called this its 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.*

### *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 and environmental footprint of resource extraction. Kiwetinohk is experimenting on well design where it sees upside potential far outweighing downside cost.
- Kiwetinohk is advancing evaluation of several carbon capture technologies and planning to pilot test a new technology and new solvent on the Opal *Firm Renewable* plant. Kiwetinohk has obtained AUC power plant and EPEA industrial approvals, progressed preliminary detailed engineering and is targeting to reach final investment decision ("**FID**") for Opal *Firm Renewable* by end of 2023.

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 endeavor 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 market systems, setting rules that apply to everyone, and subsidizing, if necessary, 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.

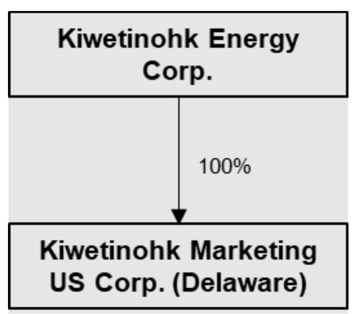
## CORPORATE STRUCTURE

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. Effective January 1, 2022, Distinction Energy (Alberta) Limited and Kiwetinohk amalgamated under the CBCA and continued as Kiwetinohk.

Kiwetinohk's principal office is located at Suite 1700, 250 – 2$^{nd}$ 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.




The Company anticipates creating various limited partnership structures as it builds out and finances its green energy projects.

## GENERAL HISTORICAL DEVELOPMENT OF THE BUSINESS

**Three Year History**

***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.

***2021***

- January 15 – 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").

- February 17 – 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 (collectively, the "**Simonette Assets**"), 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.

- March 6 – 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*".

- April 28 – 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.

- Additionally on such date, 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.

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

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

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

- September 15 – Kiwetinohk appointed Janet Annesley as Chief Sustainability Officer.

- September 22 – 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.

- November 11 – the Company appointed Mike Backus as Chief Operating Officer (Upstream Division).

- November 24 – the TSX conditionally approved the listing of the Common Shares. Listing was subject to the Company fulfilling all of the requirements of the TSX on or before February 22, 2022.

- November 25 – William (Bill) Slavin resigned from the Board.

- November 29 – Kiwetinohk appointed John Maniawski as President of the Green Energy Division.

- December 13 – Kiwetinohk amended its Credit Facility and increased the borrowing limit from $225 million to $315 million and expanded its lending syndicate to six banks.

- December 31 – Distinction Energy Partnership (Alberta), 11200305 Canada Inc. and Distinction Energy Corp. (a Delaware entity), all subsidiaries of the Company, were dissolved as part of year-end corporate clean-up.

***2022***

- January 14 - Kiwetinohk's common shares were listed on the TSX with the trading symbol KEC.

- February 3 - Kiwetinohk appointed Judith Athaide and John Whelen as new independent directors and appointed Chris Lina as Vice President, Projects.

- March 23 - Tim Schneider resigned from the board of directors.

- April 18 - Kiwetinohk filed a short-form base shelf prospectus to provide financing flexibility and additional options for quicker access to public equity and/or debt markets up to $500 million.

- May 18 - Kiwetinohk entered into an agreement to purchase an early state 150-300 MW solar development project for cash consideration of up to $9.0 million, of which, $2.5 million was paid upon closing, and $1.5 million was paid in the third quarter of 2022.

- June 13 - Kiwetinohk increased the consolidated Credit Facility by $60.0 million to $375.0 million. The Credit Facility is comprised of an operating facility of $65.0 million and a syndicated facility of $310.0 million.

- September 15 - Kiwetinohk acquired an incremental working interest in its Placid cash generating unit for cash consideration of $59.2 million.

- October 4 - the Alberta government awarded Kiwetinohk the right to advance planning on two carbon capture and storage hubs.

**Significant Acquisitions**

No significant acquisitions were completed in 2022.

## DESCRIPTION OF KIWETINOHK'S BUSINESS

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

1. Renewable solar 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, reciprocating internal combustion 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 marketing capability is already in place whereby the Company purchases and sells natural gas to effectively utilize excess natural gas transportation capacity.)

- 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 a circular economy that creates clean energy hubs, and

- Providing natural gas, providing $CO_2$, or providing $CO_2$ 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. clean (low emissions) energy;

2. reliability of supply;

3. dispatchable power generation; and

4. low-cost affordable energy.

At the same time the development projects must be profitable, allow for costs to be recovered and generate a reasonable economic return so as to enable the Company to attract sufficient 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 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 baseload power generation from efficient NGCC plants. Kiwetinohk is investigating 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 believes 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, industry leading 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 of natural gas to existing markets or other locations which may be suitable for construction of a power or hydrogen project for consumption of the natural 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, highly efficient, natural gas-fired power projects, to allow the Company to capture an increased share of gross margin through participation in the full value chain from upstream resource to clean, low emissions power generation. Specifically, the Company can attain competitive advantage in the power market by having a lower marginal cost than other power market participants, thereby increasing its power sales. The Company can also choose to sell its natural gas directly to natural gas markets or supply directly to its gas-fired generation based on the prevalent natural gas and power market pricing conditions. 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 Projects***

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

1. utility scale solar power,

2. *Firm Renewable,* and

3. large-scale NGCC power.

The AESO has a six-stage process[7] 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 (the "**AUC**") and under the Environmental Protection and Enhancement Act (the "**EPEA**"). These approvals have overlapping requirements and they are pursued concurrently.

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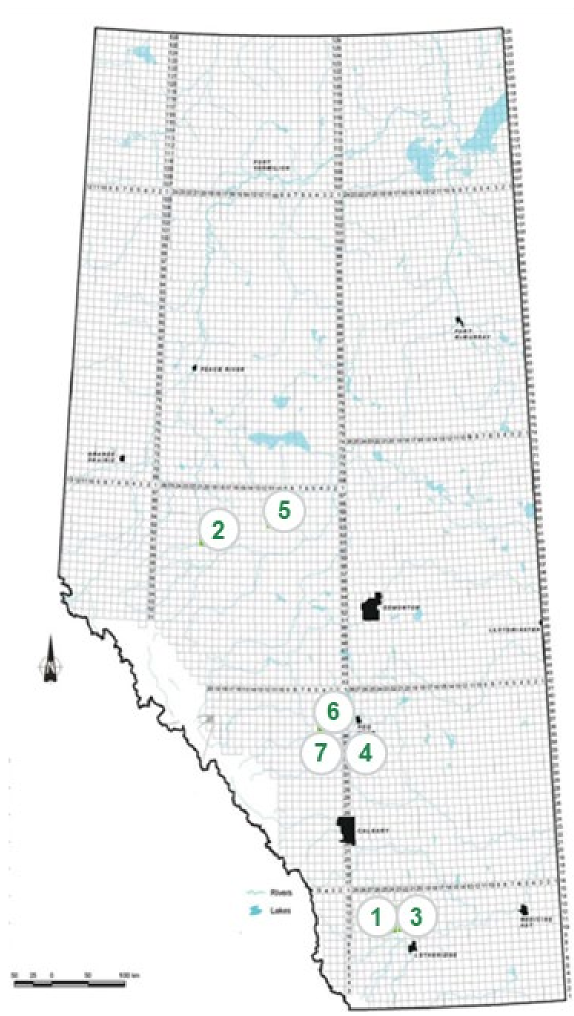
[7] "Connection Process", online: *aeso* <https://www.aeso.ca/grid/connecting-to-the-grid/connection-process/>.

Early-stage development and design factors and the status of each project as at March 7, 2023 are summarized in the following table. Locations on the following map are ascribed from left to right starting with the Homestead project.

| **Project** | **1** | **2** | **3** | **4** | **5** | **6** | **7** |
|---|---|---|---|---|---|---|---|
| **Early-stage Green Energy development, design factors & status** | **Homestead (Solar 1)** | **Opal (Firm Renewable 1)** | **Granum (Solar 2)** | **Phoenix (Solar 3)** | **NGCC 2** | **NGCC 1** | **Firm Renewable 2** |
| Approximate Capacity (nameplate, AC) | 400 MW | 101 MW | 350 MW | 170 MW | 500 MW | 500 MW | 124 MW |
| Approximate Capacity (net to grid, AC) | 400 MW | 97 MW | 350 MW | 170 MW | 460 MW | 460 MW | 120 MW |
| Capacity factor | 27% [6] | 50% [7] | 27% [6] | 27% [6] | 90% | 90% | 50% [7] |
| Heat rate [8] (MJ/KWH: +/-5%) | - | 7.6 | - | - | 6.0 | 6.0 | TBD |
| AESO stage | 3 | 3 | 2 | 3 | 2 | 3 | 2 |
| Earliest FID date | Q4 2023 | Q4 2023 | Q2 2024 | Q1 2024 | 2H 2024 | 1H 2025 | TBD [9] |
| Earliest COD date[4] | Q4 2025 | Q4 2025 | Q2 2026 | Q3 2025 | 2H 2027 | 1H 2028 | TBD [9] |
| Total estimated installed capital cost ($ million) [1, 2, 3, 5] | $750 (Class 2) | $156 (Class 3) | $660 (Class 3) | $320 (Class 4) | $875 (Class 4) | $875 (Class 4) | Preliminary estimate underway |

1 – Total installed cost estimates are classified in a manner consistent with American Association of Cost Engineering ("AACE") standards.
2 – Total installed cost numbers exclude carbon capture and sequestration for gas-fired projects ("CCUS"). Preliminary carbon capture capital cost for an NGCC power plant is estimated to be an incremental 60 to 80% of the total installed power plant cost based on a third party engineering study (March 2022), and for Opal, an incremental 70 to 100% of the total installed power plant cost based on an independent engineering study (January 2023).
3 – 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.
4 – If an FID decision is reached, the Company will advance the project towards an estimated Commercial Operations Date ("COD").
5 – Capital costs may increase due to, among other things, the state of the current economic environment and related inflation and supply chain challenges; specific capital cost adjustments will be applied as projects progress through engineering review stages. Homestead Solar capital cost estimate updated with completion of Class 2 estimate on June 8, 2022. Pre-Feed studies by a third party engineering firm on NGCC plants (January 2023) validate previous estimates.
6 – First year capacity factor based on DC/AC ratio of 1.35, and bifacial, single axis solar panel tracking design.
7 – Designed for intermittent operation. The actual dispatch will be based on market conditions and contracting.
8 – Gas-fired generation simple cycle heat rates averaged 9.5 and NGCC heat rates averaged 7 on existing projects within the AESO grid as per publicly available data.
9 - Kiwetinohk has advanced development of the project including progressing AESO stage reviews, securing a project site, initiating a preliminary capital cost estimate, and reviewing project schedule.

## PROJECT LOCATIONS IN ALBERTA




***Solar Power – Projects in Development.***

Kiwetinohk's renewable energy strategy focuses on solar power project development in southern and central Alberta and is the cornerstone of the Company's current renewable energy development portfolio. Kiwetinohk obtained AUC power plant approval for the expected 400 MW Homestead Solar project, its largest solar project, in September 2022, with AUC transmission approval expected by Q4 2023. Kiwetinohk has advanced the expected 400 MW Homestead Solar and the expected 170 MW Phoenix Solar projects, to AESO stage 3, and the expected 350 MW Granum Solar project to AESO Stage 2. The Company intends to select a financing partner and make its final investment decision on the Homestead Solar project by Q4 2023.

Kiwetinohk undertakes a comprehensive screening process to select potential sites for solar power development, reviewing locations based on: (a) interconnection (AESO grid) capacity availability; (b) cost modelling; (c) environmental factors; (d) landowner and other stakeholder considerations; and (e) 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 up to 950 MW of solar power generation capacity spread between the three greenfield projects in the Kiwetinohk solar portfolio.

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 developments. For its renewable power portfolio overall, Kiwetinohk targets economies of scale, optimal location on the grid and leading 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 using leading available technologies that are de-risked; panels with superiority in generation capacity; and panels with material efficiency advantages.

- Inverters: Kiwetinohk targets leading 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 emission offset credits or emissions performance credits that Kiwetinohk could either use to net against its own emissions or "bank and sell" to maximize profit. Kiwetinohk will also look to maximize solar renewable value overall by coupling its solar power projects 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. The 101 MW Opal *Firm Renewable* project obtained AUC power plant approval in August 2022 and EPEA industrial approval in December 2022. Kiwetinohk has advanced Opal to AESO Stage 3. A site has been secured and geotechnical surveys have been completed, community consultation for the power plant has been completed, AUC transmission regulatory process is being advanced by ATCO, gensets have been selected and the FEED work and cost estimate are complete. The Company has been working with a well-known manufacturer, Bergen, and its partner, SAMPOL, an engineering, procurement and construction management firm, to advance detailed engineering and develop a turnkey proposal to supply and construct the first project. Kiwetinohk is currently exploring options for financing the project.

Kiwetinohk has advanced development on a second *Firm Renewable* project, a 124 MW, which employs the same technology as the Opal *Firm Renewable* project. Kiwetinohk has progressed the project to AESO Stage 2, and secured an option for land.

*Firm Renewable* is the Company's term for high efficiency, flexible-output, low emissions, internal reciprocating engine, gas-fired power generation. These gensets are able to respond very quickly to supply power as required to address volatility of grid supply, power pricing signals and supply shortages. Supply volatility has proven to be a problem for power grids that have taken on a high percentage of renewables, including wind and solar power. The Firm Renewable projects that Kiwetinohk is pursuing are designed to operate at relatively high efficiency (for simple cycle thermal power) in the high 40s percentage range and present designs can tolerate up to 15% hydrogen in the fuel gas. The engine-generator sets are rated to accelerate from warm condition to full power in three (3) minutes and can operate efficiently over a broad range of utilization (i.e., 5% to 100%). The Opal *Firm Renewable* project, which consists of 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 are emerging technologies that may eventually provide sufficient power output or storage duration) for short duration needs, or simple cycle gas-fired power for longer duration requirements. The Company believes that the hardware selected for its first Firm Renewable project offers the best choice of current technologies to meet this very important need for the grid power system.

***Firm Renewable - CCUS***

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 demonstration project. The demonstration project will also have the ability 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 has completed a pre-FEED study on an emerging carbon capture technology, conducted an evaluation of various commercially available and emerging carbon capture technologies and recently developed enhanced solvents, for the Opal Firm Renewable project. The Company shortlisted carbon capture technology candidates, and plans to evaluate these in a second pre-FEED study. In addition, an independent engineering firm completed an analysis for carbon capture on intermittently operated, gas-fired power plant, and produced an optimal design configuration and preliminary cost estimate for commercially available carbon capture on the Opal power plant. This estimate concluded that the capital cost of carbon capture at the power plant is an incremental 70 – 100% of the estimated capital cost of the Firm Renewable power plant without carbon capture.

Kiwetinohk anticipates that deployment of carbon capture technology on the Company's *Firm Renewable* power plants remains highly probable over the next 5 – 10 year period, but will be driven by government regulations and policies relating to emissions, Investment Tax Credits (ITC) for CCUS, securitization of carbon offsets, and other economic factors, as well as Kiwetinohk's ability to advance technology through a demonstration project.

***Firm Renewable - Integration Benefits***

Because of the expected high efficiency (relative to Alberta's existing simple cycle power generation), Kiwetinohk's *Firm Renewable* projects are expected to have attractive economics across a broad range of grid power prices. Kiwetinohk expects that, as renewable wind and solar projects are added to the grid, high-power-price events will happen more frequently due to the intermittency of renewables. 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. In addition, KEC plans on providing a dedicated supply of natural gas production to its *Firm Renewable* plants, creating a competitive advantage to its peers.

Kiwetinohk expects to access higher value for natural gas production through conversion to power sales. Kiwetinohk's anticipates that its supply cost of natural gas to its *Firm Renewable* projects will be below the general market price enabling it to capture these synergies in the electricity market. However, the pool price in the electricity market is dependent on many factors such as the market structure and competition in that market. For example, an increase in intertie capacity may lead to higher participation of electricity imports by low carbon sources into Alberta which may impact pool price.

**NGCC – Projects in Development**

Kiwetinohk has advanced development on two NGCC power plants including AESO review, pre-FEED evaluation, consultation, environmental studies and preparation for regulatory applications. NGCC 1 has been advanced to AESO Stage 3, and NGCC 2, AESO Stage 2. Pre-FEED evaluation has been completed on the power generation facility and carbon capture segments of the NGCC projects. The NGCC projects are in attractive locations with favorable access to electrical transmission, grid capacity, gas transportation and sequestration hubs. NGCC 1 has an option secured on its site, and NGCC 2 has a targeted location with site evaluation and review progressing favorably.

The NGCC power 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 baseload generation to the grid.

NGCCs have limited dispatchability, while wind and solar power lack dispatchability. *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 on a commercial basis. The Company believes that NGCCs with CCUS are the best commercially proven alternative.

Kiwetinohk's proposed NGCC power plants are designed and expected to be more efficient than existing gas-fired generation in Alberta with a targeted emissions intensity of 0.35 tonne/MWh. Kiwetinohk expects the high efficiency of its proposed NGCC power plants may provide operating cost advantage over the existing gas-fired power fleet. In addition, Kiwetinohk expects to deploy existing, commercially available carbon capture technology on its NGCC plants with a target of at least 90% carbon capture.

***NGCC - CCUS***

Kiwetinohk is advancing evaluation and development of its two NGCC projects including CCUS technology and storage alternatives (sequestration in deep saline aquifers and/or EOR). 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. The emissions impact of NGCC 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 economic risk. Further, recent development in solvents for CCUS use suggests that superior CCUS system performance may be achievable, and these technologies may warrant testing at a demonstration scale level with an NGCC plant. Kiwetinohk's NGCC projects have not yet reached the decision point whether to install full capacity CCUS from the start or to defer implementation until commercially available technologies and solvents are further evaluated and optimized for the Company's NGCC power plants.

Kiwetinohk is continuing the development of NGCC 1 and 2 power projects with CCUS using a standard amine process that is commercially available. Kiwetinohk has completed several years of research, third party studies and a pre-FEED study of carbon capture for NGCC 1 and 2, which support Kiwetinohk's goal to deploy over 90% emissions free, gas-fired baseload generation as a key component of the Company's Green Energy strategy.

Kiwetinohk is finalizing a pre-FEED evaluation by an independent engineering firm for commercially proven carbon capture technologies for its NGCC power projects. The pre-FEED study concludes that the estimated capital cost of carbon capture at the power plant is an incremental 60 – 80% of the estimated capital cost of the NGCC power plant without carbon capture.

Based on Kiwetinohk's research and third-party studies, the Company anticipates that carbon capture technology will be commercially available to deploy on its NGCC 1 and 2 power projects. Kiwetinohk anticipates that the finalization of the income tax credits ("ITCs") for CCUS and the added financial certainty around carbon offset credits under federal and/or provincial government programs to support the additional capital and operating costs of the CCUS system for the Company's NGCC power plants.

Kiwetinohk does not have a detailed engineered cost estimate for full carbon capture on any of its gas-fired plants. As stated previously, the Company's preliminary capital estimates for capture are in the range of 60 to 80% of the installed capital cost of NGCC without carbon capture, and 70 – 100% of *Firm Renewable* without carbon capture. 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[8] with some emerging technologies approaching US$30 to US$40 per tonne of $CO_2$ captured[9]. Addition of $CO_2$ capture onto a powerplant is estimated to reduce its thermal efficiency power output by 4-10%[10], which implies that 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 requiring technology 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.

**Carbon Hubs - Carbon Capture, Utilization and Storage**

*The Government of Alberta has awarded Kiwetinohk the right to advance planning on two carbon sequestration hubs for storing carbon dioxide. In addition to developing a carbon sequestration hub for each of its gas-fired power projects,* Kiwetinohk *is also looking to provide carbon capture and sequestration services to other emitters in proximity to its power projects.* Having proprietary access to carbon storage is anticipated to significantly de-risk Kiwetinohk's associated gas-fired power projects.

The Company has screened the local area and has identified up to approximately 2 million metric tonnes per year of emissions at each carbon hub which include Kiwetinohk's proposed gas-fired power projects. Kiwetinohk is currently conducting a detailed feasibility study to confirm that the carbon hubs have sufficient capacity to capture emissions from both the power project and regional third-party emitters.

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

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

[10] 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.

**Hydrogen and Other Initiatives**

Kiwetinohk's current efforts are mainly focused on natural gas production and power generation (with associated CCUS) in Alberta. The Company is also actively investigating:

- power generation and/or hydrogen production in the Chicago area where the Company currently ships 120 mmcf/d of liquids-rich natural gas on the Alliance pipeline for the greater Chicago market.

- hydrogen production in Alberta: Kiwetinohk is monitoring the relevant technologies and looking for investment opportunities in blue and green hydrogen projects. One project is at 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. A non-binding Memorandum of Understanding has been executed both parties have dedicated significant in-kind resources to the advancement of the project.

- another specific hydrogen initiative under early-stage consideration involves manufacture of ammonia for export to Pacific Rim markets, and

- providing its products and services (electricity, natural gas, hydrogen, $CO_2$, and $CO_2$ sequestration) to other co-located business.

These investigations 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 ventures 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 is developing a portfolio of renewable and gas-fired power projects that are expected to ultimately provide attractive returns and deliver long-term, sustainable free cash flow. The Company has largely developed its own early-stage projects using internal funding. The Company 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. Currently the Company is actively progressing an approximately 2,150 megawatt generation portfolio, consisting of proposed solar, Firm Renewable and NGCC power projects, towards FID. As projects approach FID, sites and technology are selected, cost estimates are confirmed and, marketing plans and contracts are determined the investment risk will be significantly reduced.

Kiwetinohk expects to spend a range of $3 to $8 million to bring each power project to a FID, dependent on project requirements. Concurrent with reaching a FID, the Company will be seeking optimal financing of its power projects using a combination of company and third-party equity and debt to fund its projects through construction. Due to the higher upfront risk involved in identifying and advancing downstream projects prior to FID, Kiwetinohk is pursuing multiple potential paths to financing its power projects with the goal of achieving a competitive rate of return on capital aligned with its upstream business. The following table summarizes financing strategies the Company is reviewing for its power project portfolio.

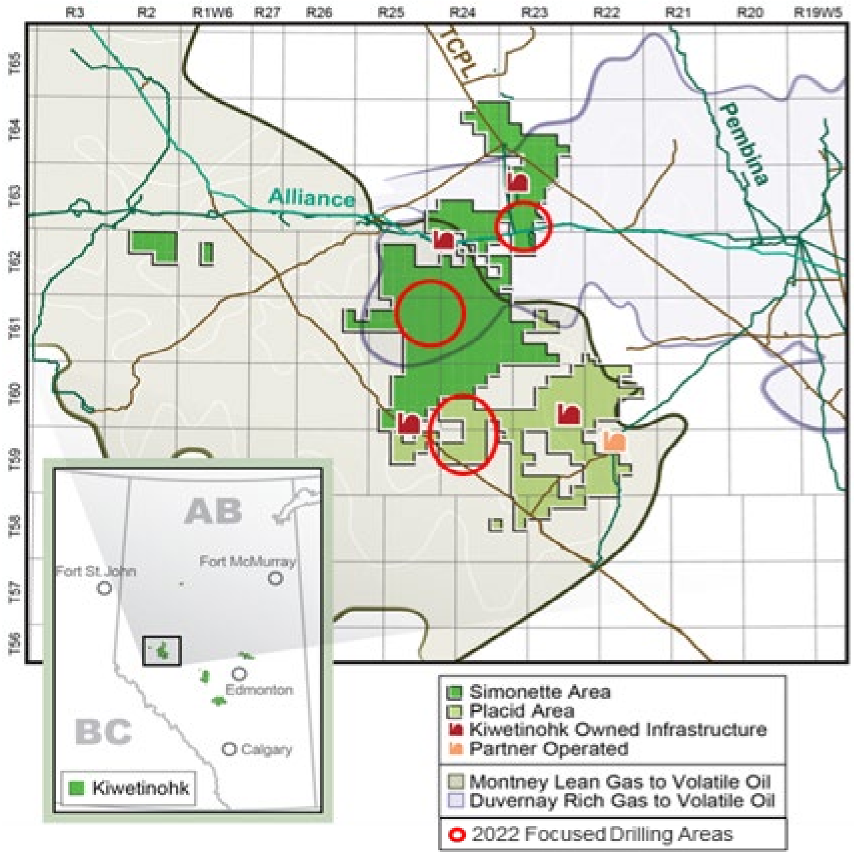
| Financing Strategy | Strategy Description |
|---|---|
| Carried equity interest | Earn a carried equity interest in the long-term economics of a project in exchange for the risk and costs incurred to bring it to FID. No further equity capital would be required by the Company post FID. |
| Carried equity interest and co-invest | Earn a carried equity interest for bringing a project to FID and co-invest with third party investors at the project FID stage to further increase the Company’s working interest in the project. |
| Strategic partnership | Enter into a strategic partnership with a party or parties to invest across the Company’s entire power portfolio.<br><br>The Company may also look to access other financial supports, including Indigenous financing sources and export credit agency funding and guarantees.<br><br>Kiwetinohk also intends to apply for grants in areas of interest, such as CCUS, where available and appropriate. |
| Full development and subsequent sell down | The Company would fund the construction of a power project, which may include participation of external investment counterparties, and sell down a significant working interest at commercial operation date (COD). |

Kiwetinohk believes successful execution of its investment and financing strategies for its power project portfolio 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.

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 limited partnerships selectively 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 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 current operations are primarily focused in the Fox Creek region.




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 2022 Reserves Report.

| | Gross Production (Fourth quarter 2022 daily average) | | | | Gross Reserves Proved Developed Producing (3) | | | |
|---|---|---|---|---|---|---|---|---|
| | NGL(4) | Crude Oil (1) | Shale Gas | Total | NGL(4) | Tight Oil | Shale Gas | NPV10(5) |
| Property | bbl/d | bbl/d | mmcf/d | boe/d | mmbbl | mmbbl | bcf | $mm |
| Fox Creek Region | 10353.9 | 484.8 | 81.0 | 24335.4 | 17.2 | 1.0 | 128.4 | 716.7 |
| Other Misc. | 107.9 | 140.1 | 1.0 | 409.5 | 0.2 | 0.3 | 1.7 | 18.0 |
| **TOTAL (2)** | **10461.8** | **624.9** | **81.9** | **24744.9** | **17.4** | **1.3** | **130.1** | **734.7** |

| | Gross Reserves Total Proved (3) | | | | Gross Reserves Total Proved plus Probable (3) | | | |
|---|---|---|---|---|---|---|---|---|
| | NGL(4) | Tight Oil | Shale Gas | NPV10(5) | NGL(4) | Tight Oil | Shale Gas | NPV10(5) |
| Property | mmbbl | mmbbl | bcf | $mm | mmbbl | mmbbl | bcf | $mm |
| Fox Creek Region | 54.9 | 1.0 | 412.9 | 1,568.0 | 91.2 | 1.1 | 726.4 | 2,521.1 |
| Other Misc. | 0.3 | 0.3 | 1.8 | 14.2 | 0.3 | 0.4 | 2.1 | 17.6 |
| **TOTAL (2)** | **55.2** | **1.3** | **414.7** | **1,582.3** | **91.5** | **1.5** | **728.5** | **2,538.8** |

**Notes:**
(1) Includes light and medium crude oil and heavy crude oil.
(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 2022 Reserves Report with an effective date of January 1, 2023.
(4) For NI 51-101 purposes, condensate production is included with NGL production
(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** | 144,754 | 97,498 | $26.1 | $76.6 | $25.7 |
| **Other Misc.** | 74,509 | 21,331 | $11.6 | $3.1 | - |
| **Total (4)** | **219,263** | **118,829** | **$37.7** | **$79.7** | **$25.7** |

**Notes:**

(1) Landholdings shown above are net acres in the Montney and Duvernay formations, among others. Acreage position is expressed as at December 31, 2022. 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.

(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 68% of Kiwetinohk's decommissioning liabilities on its financial statements are associated with active properties that have production and attributable reserves. There is approximately $37.7 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. Kiwetinohk 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.

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 pipeline transportation contracts
- Potential consolidation opportunities in the region

Development in the Simonette area has primarily been focused on the liquids-rich Duvernay formation, however there is also production from the overlying Montney formation on the same land base. Production from the Simonette asset averaged 16,920 boe/d in Q4 2022 (46% liquids) comprised of 1,579 boe/d NGL, 6,188 boe/d in oil and condensate, and 54.9 mmcf/d shale gas.

In the Placid area, just south of Simonette, the liquids-rich Montney is the primary formation for development. Production from the asset averaged 7,416 boe/d in Q4 2022 (41% liquids) comprised of 1,015 boe/d NGL, 2,057 boe/d oil and condensate and 26.1 mmcf/d shale gas.

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 is also focus on a few wells in the Montney in the Simonette area. As outlined in the 2022 Reserves Report, McDaniel assigned total proved plus probable reserves to approximately 20% of the Simonette assets. The Company cored a vertical well to evaluate a lower porosity bench that covers 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 drill 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 (acquired by ARC Resources in April 2021), 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. In its evaluation under the 2022 Reserves Report, McDaniel assigns 73 remaining Duvernay and 10 Montney 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
- Electrification of frac spreads and drilling rig components
- Artificial lift system selection and adaptation and operation optimization
- Cyclic gas injection enhanced liquids recovery

Many of these value optimization opportunities are expected to improve economics, 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 89.2 mmcf/d and a combined natural gas liquids (excluding condensate) capacity of 3,650 bbl/d. Condensate stabilizers at both plants add 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 of capacity for rich gas from Simonette on the Alliance system (in addition to 29.7 mmcf/d capacity on Alliance (from Distinction) in the Placid area). The gas plants are also connected to the Pembina Pipeline system for transportation of natural gas liquids and condensate to Fort Saskatchewan and Edmonton, Alberta respectively. The Company also utilizes the NGTL system for gas transport in the Placid area and will soon have access in Simonette.

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 2022 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 Reserves Report were averaged by Kiwetinohk according to the planned drilling in 2022 and are tabulated below by formation:

***US$70/bbl WTI and US$3.00/mmbtu Henry Hub***

| | DUVERNAY | MONTNEY |
|---|---|---|
| IRR before tax (%) | 253 | 138 |
| PIR15 before tax (ratio) | 1.24 | 0.89 |
| Break-even 15% NPV WTI ($/bbl) @ HH = $USD 3.00/ mmBtu | 27.58 | 43.08 |
| Break-even 15% NPV HH ($/mmBtu) @ WTI = 70 $US/bbl | -1.82 | -2.65 |

***US$100/bbl WTI and US$4.50/mmbtu Henry Hub***

| | DUVERNAY | MONTNEY |
|---|---|---|
| IRR before tax (%) | >500 | 380 |
| PIR15 before tax (ratio) | 1.93 | 1.47 |
| Break-even 15% NPV WTI ($/bbl) @ HH = $USD 4.50/ mmBtu | 13.29 | 33.16 |
| Break-even 15% NPV HH ($/mmBtu) @ WTI = 100 $US/bbl | -4.98 | -6.82 |

**Notes:**

(1) The economics tabulated above used the well designs and production forecasts prepared by McDaniel in connection with the 2021 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 12 (Duvernay) and 4 (Montney) well program in 2023. Operating costs were forecast at $13,500/well/month fixed and variable costs of $0.25/mcf (sales), $5.75/barrel of condensate and $2.00/barrel of oil for the Duvernay wells, and $11,500/well/month fixed and variable costs of $0.75 /mcf (sales), $0.60/barrel of condensate and $3.00/barrel of water for the Montney wells. Economics presented are based on a WTI price of US $70/ bbl and 3.00 $USD Henry Hub with a foreign exchange rate of 0.73 $US/$ and WTI price of US $100/ bbl and 4.50 $USD Henry Hub with a foreign exchange rate of 0.79 $US/$.

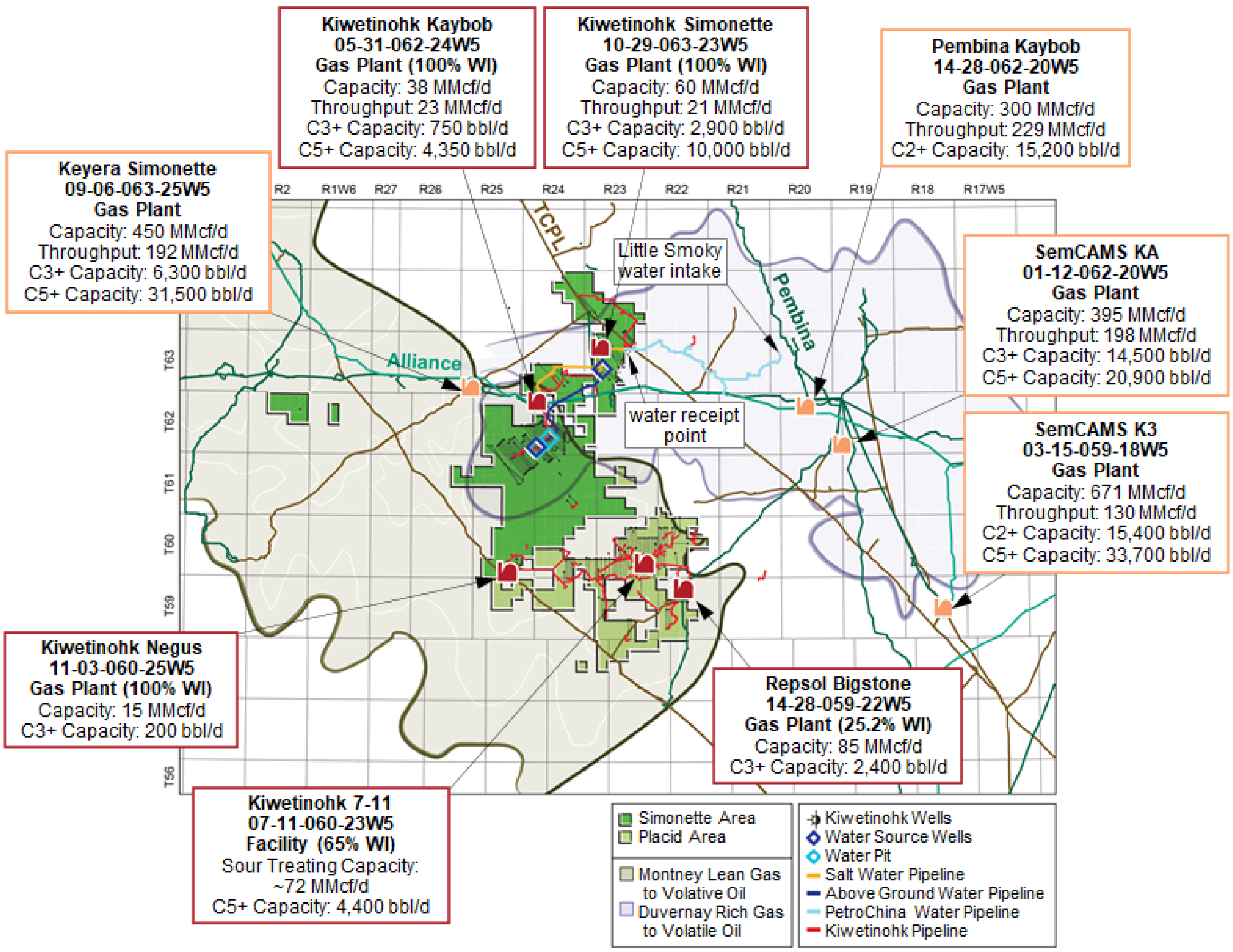
IRRs, PIRs and break-even IRR 15% WTI and AECO prices in respect of Duvernay and Montney properties set forth herein represent management's estimates based on, among other things, those metrics and assumptions set forth herein. Our IRRs, PIRs and break-even IRR 15% WTI and AECO prices in respect of our Duvernay and Montney properties set forth herein and are based on numerous estimates and assumptions, including those set forth herein and additional assumptions of our management based on historical data, extrapolations therefrom and our management's professional judgement, which involves a high degree of subjectivity. For these reasons, such estimates have an inherent degree of risk and actual results may differ from our estimates herein and the differences could be significant. As such, such estimates should not be unduly relied upon. These estimates also constitute forward-looking statements which are subject to certain risks and uncertainties. See “Forward-Looking Statements and Market Data” and “Risk Factors”.

### *West Central Alberta*

The Company's assets in the West Central Alberta Duvernay formation lie 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.

### 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. Company-owned infrastructure with 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 markets, and remaining natural gas is sold into the Chicago area and interconnecting markets. The Alliance Pipeline is connected to the Company's two Simonette gas plants and to a third non-operated gas plant, where Kiwetinohk has a working interest ownership, which processes residue gas from Placid. Kiwetinohk currently has a contract to deliver 120 MMcf/d of natural gas into the Alliance pipeline for sale in 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 other producers. 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.

*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 1.1 mmcf/d of NGTL service effective May 1, 2021, which expires in mid-2024, and separate and independent NGTL contracts for 20.1 mmcf/d associated with its Placid region expiring on March 31, 2026. Kiwetinohk has negotiated an incremental 9.2 mmcf/d of firm service which will commence on or about April 1, 2023 in association with an interconnection to its Simonette 10-29 gas plant.

*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 Company's two Simonette gas plants are directly connected to the Pembina Peace Pipeline. Kiwetinohk has agreements with Pembina for transportation of 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 in the Placid area to a full-service terminal at Fox Creek where the liquids are sold onto Pembina's pipeline system. No take-or-pay commitments are associated with the pipeline but the agreement does have a production dedication area.

*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, 2024 |
| Pembina | NGL and C5+ Transportation from Simonette to Fort Saskatchewan and Edmonton | --(1) | --(1) |
| Pembina | NGL Fractionation in Fort Saskatchewan | --(1) | --(1) |

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

In addition to delivering its own production, the Company has acquired approximately 45,000 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 and differentiate Kiwetinohk from its competition using:

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

Leading Kiwetinohk's operations, project and ongoing engagement with stakeholders, the Company's strong and experienced executive management team consists of the following individuals, as of the date of this AIF:

| Name and Title | Overview of Relevant Experience |
| --- | --- |
| **Patrick Carlson** (1)<br>*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.<br><br>Pat has received numerous professional and industry awards:<br><br>• Schulich School of Engineering, Distinguished Alumni Award for Leadership, 2019<br>• Canadian Petroleum Hall of Fame, Inductee, 2018<br>• Alberta Chamber of Resources, Resource Leadership Award, 2017<br>• Grande Prairie Chamber of Commerce, Business Citizen of the Year, 2016<br>• Schulich School of Engineering, Canadian Engineering Leadership Award, 2013<br>• Lloydminster Oilfield Technical Society, Oilman of the Year 2008<br>• 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.<br><br>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.<br><br>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)<br>*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.<br><br>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.<br><br>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 advisory boards for Clean Prosperity and Export Development Canada, and on the boards of the Southern Alberta Institute of Technology and the City of Calgary Green Line LRT Project. |
| **Mike Backus** (1)<br>*Chief Operating Officer, Upstream* | Mike Backus is the Upstream Chief Operating Officer for Kiwetinohk. 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 two private companies and previously a charitable organization.

**John Maniawski**(1)
*President, Green Energy Division*

John Maniawski is the President, Green Energy Division and in this role leads the team responsible for the strategic planning, development and execution of Kiwetinohk's renewable and gas-fired power generation, clean energy opportunities, CCUS, large-scale energy storage and hydrogen production.

John has more than 30 years' diverse experience in the power, utility, pipelines, and customer energy solutions sectors. He has held senior leadership roles at Evolugen (Brookfield Renewable – Canada), Enbridge and ENMAX in strategic planning, business development, energy marketing, project execution, asset management, operations, and engineering.

As Senior Vice President, Business Development for Evolugen, John directed the strategic planning and business development of a customer-focused renewable and low carbon business, as well as the energy marketing and regulatory overview of a 1,700 MW hydro and wind portfolio. As Head of Power Generation Business Development, Americas at Enbridge, John led and supported the strategic planning, development, and acquisition of an approximately $4 billion and 2000 MW renewable energy platform in North America.

John holds a Bachelor of Science in Electrical Engineering from the University of Saskatchewan, and a Master of Business Administration from the University of Calgary. He is a Professional Engineer in Alberta.

**Jakub Brogowski** (1)
*Chief Financial Officer*

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 $47 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.

**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.

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.

**Chris Lina**
*Vice President, Projects*

Chris Lina is a senior facilities engineering, procurement and construction management project leader with more than 25 years' experience in mega projects from inception to completion including start up and commissioning.

Originally from Germany, Chris started his career with UHDE, an engineering, procurement, construction and technology license company for petrochemicals where he developed a strong technical background in hydrogen, ammonia and methanol processes.

Chris immigrated to Canada in 1999 to work on the world's largest hydrogen plant for Shell Canada in Edmonton. He then continued to build and lead teams to deliver several other world-scale projects in oil and gas and petrochemicals.

Chris has a well-rounded technical, project, operations, and business background. He understands how complex plants with different technologies are designed and built to operate safely, economically and with the desired reliability and onstream factors. In his last billion-dollar projects with North West Redwater Partnership and Canada Kuwait Petrochemical Corp., Chris played an integral role in helping develop processes, hiring teams and building the culture.

Chris has a Master of Science in Chemical Engineering from University of Karlsuhe.

**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.

**Frank Angyal**
**Vice President, Drilling**

Frank holds a Bachelor of Science Degree in Petroleum Engineering from the University of Alberta and is a registered Professional Engineer in Alberta. He started working in the oil and gas business as a Drilling Engineer in Australia in 2008. He returned to Canada in 2010 and worked for a Resource Management firm on a variety of projects until joining Seven Generations Energy in 2013.

From 2013 to 2018, Frank worked in various drilling roles for Seven Generations Energy starting as a Wellsite Supervisor for both Montney and Duvernay wells and eventually moving to an office based role where he initially took on Drilling Superintendent/Drilling Engineering duties and eventually took on the role of Well Operations Team Lead. Aiding in the development and implementation of new technologies, the drilling costs were reduced by 65%. He efficiently managed a $400MM/year drilling operation (average 10 rigs/day) in the KAAR/KAKWA area. Frank has designed and drilled over 300 wells with over 3000 meters TVD and 3000 meters lateral leg length in the deep high pressure Montney and Duvernay formations.

Frank joined Kiwetinohk in November of 2018 as a Senior Drilling Superintendent and moved into the role of Manager, Drilling in November of 2021.

**Shelley Leggitt**
**Vice President, Geoscience**

Shelley Leggitt is VP Geoscience and brings 35 years of technical and leadership experience in both conventional and unconventional plays in Western Canada. Prior to joining KEC, Shelley was VP Geoscience at Velvet Energy responsible for a large technical team working on leading edge technologies to develop the Montney at Gold Creek and Pouce Coupe and further develop seismic techniques to exploit deep basin gas.

Prior to Velvet Energy, Shelley was VP exploration at NAL Resources working a large portfolio of assets extending from SE Sask to AB Sturgeon Lake Montney. A highlight of her career was her tenure as Exploration Manager at EOG Canada responsible for early development of the Horn River Basin and initial exploration and the first well in the Duvernay East Shale basin. Shelley has also held leadership roles at Enerplus and Encana/PanCanadian and worked early in her career at the Petroleum Recovery Institute where she focused on enhanced oil recovery projects.

Shelley holds a Masters degree in Geology from McMaster University and is a registered Professional Geologist in Alberta. Shelley has been active with the Canadian Society of Petroleum Geologists for many years, having served as finance director, Geoconvention chair, and is currently education director and Calgary Geoleaders co-chair.

**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. Under his leadership, 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 Parsons 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.

| | |
|---|---|
| **Lyle Strom**<br>*VP, Petroleum Marketing* | Lyle Strom joined Kiwetinohk as Vice President, Petroleum Marketing in September 2021. Lyle has broad experience in the management of risk, trading and marketing of energy products throughout North America. Recently, Lyle was instrumental in initiating Canada's first EO100 Certification of the Kakwa River Project and Canada's first physical sale of natural gas to an LNG exporter. Previously, Lyle was Director, Marketing of Seven Generations from 2016 until its takeover by ARC Resources Ltd. in April of 2021. Prior to joining Seven Generations full time, Lyle was the principal in a successful consulting company for over 11 years providing marketing advisory services mostly to junior oil and gas companies. Prior to his consulting business, Lyle was the Canadian Vice President & Managing Director in a merchant energy trading business owned by a large US utility.<br><br>Lyle has over 29 years in the energy sector with almost 28 of those in the marketing and trading of energy commodities emanating from western Canada. Lyle is a graduate of the University of Calgary with a degree in Economics and is also a Dino Hockey and Moose Jaw Warrior Alumni. |
| **Kevin Nielsen**<br>*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.<br><br>Kevin is active within the energy industry having been a technical expert on short-term engagements with the International Monetary Fund supporting various IFRS training missions most recently in Africa, is a past governor at the Calgary Petroleum Club and leads the Joint Interest Research Committee of the Energy Accountants Society of Canada. |
| **Mark Friesen**<br>*Director, Investor Relations* | Mark Friesen holds a Chartered Financial Analyst designation and has over 25 years of experience in energy finance and capital markets.<br><br>Mark worked in energy equity research from 1996 to 2015, covering Canadian small, medium and large cap producers, US Independent producers, integrated and oil sands companies while working at several of Canada's charter banks including RBC, TD and BMO as well as the Calgary based boutique firm FirstEnergy Capital Corp.<br><br>Mark pivoted his career to the corporate world by joining Murphy Oil where he worked in the Canadian Planning team doing project evaluations and budgeting before joining the team at Kiwetinohk in September 2019. He joined in the capacity of managing the Corporate Financial Planning and Analysis group, working with the team through the Simonette acquisition, Distinction amalgamation, multiple bank and private placement financings and the TSX public listing in January 2022.<br><br>Mark now serves as the Director, Investor Relations for Kiwetinohk while continuing to support in multiple financial capacities. Mark is a member of the Canadian Investor Relations Institute ("CIRI"). |

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

As of December 31, 2022, Kiwetinohk had 78 full time employees and 5 full time contracted staff distributed throughout the organization as illustrated in the table below:

| Employees Engaged in Full-Time Service | Number as at December 31, 2022 |
|---|---|
| Calgary Office | 59 |
| Drayton Valley Field Office | 1 |
| Grande Prairie Field Office | 2 |
| Simonette Assets | 16 |
| **Consultants Engaged in Full-Time Service** | |
| Calgary Office | 5 |

### 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.

### 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 staff health and safety expertise and 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.

### Asset Retirement Obligations

As of December 31, 2022, Kiwetinohk had $117.5 million of undiscounted asset retirement obligations including $37.7 million inactive and $79.8 million of active asset retirement obligations. The Company estimates that it will incur an additional $25.7 million of asset retirement obligations associated with future development activities contemplated by the 2022 Reserves Report.

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.

### GHG Emissions

Managing, mitigating and reducing GHG emissions while producing reliable and affordable 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. Methane is 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 of Canada’s stated goal of reducing methane emissions by 40 - 45% by 2025 (relative to 2012 emissions).

For Q4 2021, Kiwetinohk’s first full operational quarter, the Company’s GHG emissions from its oil and natural gas production and processing was 36% lower than the Canadian Natural Gas Production and

Processing and Conventional Oil industry average.[11] Kiwetinohk published an Environment, Social and Governance (ESG) report, including 2021 data, during 2022 and will publish updated upstream emissions intensities and GHG reduction information as part of its 2022 ESG reporting in 2023.

**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 is strictly regulated in Alberta. Kiwetinohk obtains water licenses 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 participation of new entrants. In some of these endeavors Kiwetinohk faces many competitors ranging from new entrants to long-established companies. In both natural gas production and power generation entrance to each business is constrained by the limitations of the large transmissions systems that gather and distribute natural gas or power. In addition, climate change-related risks have motivated governments to intervene in the economy to accelerate the transition to cleaner, low-carbon energy sources. Regulation of the energy industry affecting the Alberta petroleum business has included subsidies, penalties, taxes on carbon emissions, ceilings, and administrative delays that could potentially 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 neighbors 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.

Land conservation and management begins with smart and responsible well design, which can significantly reduce surface land disturbance and impact on wildlife.

Kiwetinohk uses large, efficient multi-well pads, which can support up to 20 wells. Through increasing the lateral reach from the surface wellhead and increasing the reach of the fractures as well as drilling longer horizontal laterals, we can enable each well to drain a larger area.

[11] Industry data from Environment and Climate Change Canada, National Inventory Report (Part 1) 1990 – 2020: Greenhouse Gas Sources and Sinks in Canada. Figure 2 – 27. Kiwetinohk data per SASB data sheet on page 100 of this report.

We are working to optimize recovery and reduce use of land through well design and longer subsurface laterals. This allows us to space well pads more widely so we can reduce the land needed for roads, pipelines, powerlines and the pads themselves.

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 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. These seasonal variations provide an overarching 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 pursued a competitive edge by experimenting with such development design parameters as well lateral length, well lateral spacing, hydraulic fracture spacing, hydraulic fracture size and fracture fluid.

There is a significant risk that climate-change related policy will create an economic environment wherein sufficient renewable energy power generation capacity is built such that higher operating cost natural gas-fired power generation gets squeezed out of the market during peak renewable generation hours. This anticipated addition of low-cost renewable power might be predicted to cause a cyclicity in operation of gas fired power and thereby an increase in the average price of power such that continued operation of and investment in natural gas fired power occurs.

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 or capacity constraint 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 licenses 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 in its efforts to become fully compliant. Kiwetinohk believes a fully compliant status was 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 oligopolistic 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 began in 1996, 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 bought and sold through the wholesale electricity market, the Power Pool. Generators may earn revenues from energy sales by submitting supply offers to the AESO. No power purchase agreements ("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 AESO 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 hourly pool price.

In 2022, the Alberta wholesale electricity market transacted approximately $14.1 billion of energy on average hourly volume of 9,883 MWh with pool prices averaging $164.46/MWh [15]. On-peak pool prices averaged $192.13/MWh while off-peak pool prices averaged $103.14/MWh[16]. Alberta power generators also have the ability, if they choose to do so, to contract their energy supply with customers at prices, specified durations, and on other terms that may vary from the pool price pursuant to a private PPA.

### *Power Generation in Alberta*

Alberta's installed generation capacity totaled 18,391 MW as of January 31, 2023 and is comprised of the following generation types [12].

**Alberta Electric System Supply**

| 1/31/2023 | Available Capacity | Percent of Capacity |
|---|---|---|
| Cogen | 5,235 | 28.47% |
| Combined Cycle | 1,810 | 9.84% |
| Simple Cycle | 2,609 | 14.19% |
| Gas Fired - Steam | 5,235 | 28.47% |
| **Total Gas Fired** | **10,894** | **59.24%** |
| Bio Mass and other | 444 | 2.41% |
| Coal | 820 | 4.46% |
| Dual Fuel | 466 | 2.53% |
| Hydro | 894 | 4.86% |
| Storage | 90 | 0.49% |
| Wind | 3,618 | 19.67% |
| Solar | 1,165 | 6.33% |
| **Total System Supply** | **18,391** | **100%** |

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 have converted to natural gas operation[18]. Coal-fired generation capacity has declined from approximately 6,300 MW at the beginning of 2016 to approximately 820 MW with 466 MW of duel fuel capacity at January 31, 2023[19]. The remaining coal-fired generation is expected to be retired by the end of 2023.

Over the past 10 years, more than 3,600 MW of wind power and 1,165 MW of solar power generation facilities have been added to Alberta's power supply. Wind and solar generation currently represent approximately 26% of the province's total installed capacity.

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 was 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 if set price is higher than pool price, and paid to AESO by the proponent if set price is lower than pool price. Following the cancellation of the REP in June 2019, the renewable corporate PPA market accelerated with several corporate buyers purchasing renewable energy through PPAs with renewable energy projects. 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, the AESO forecasts renewables and natural

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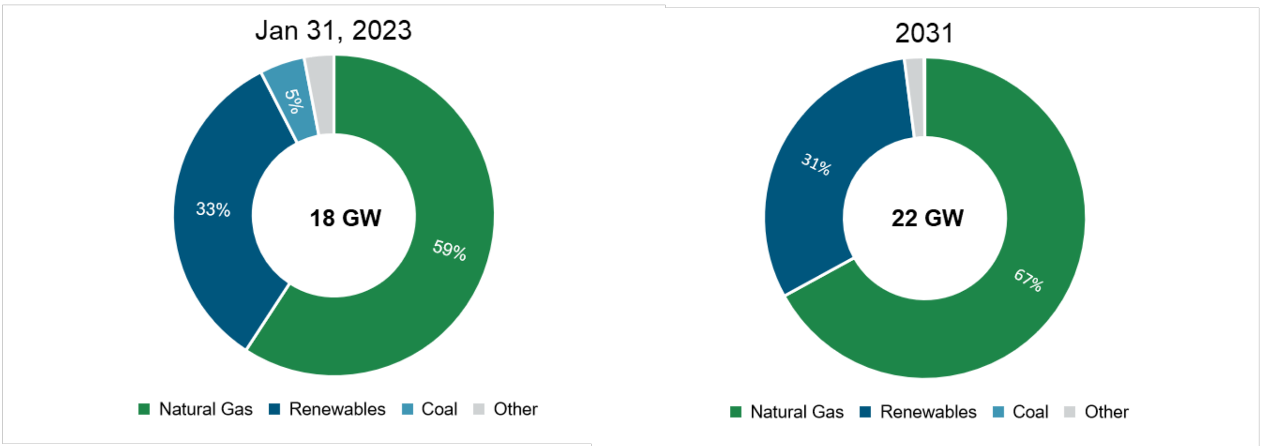
[12] "AESO Current Supply Demand Report", online: *Alberta Electric System Operator* <http://ets.aeso.ca/ets_web/ip/Market/Reports/CSDReportServlet>.

gas-fired generation to account for an increasing share of total installed capacity, ultimately reaching 98% of Alberta's electricity generation by 2031 [13] [14].




**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.

In Alberta, electricity generation and oil sands production are expected to 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[15].

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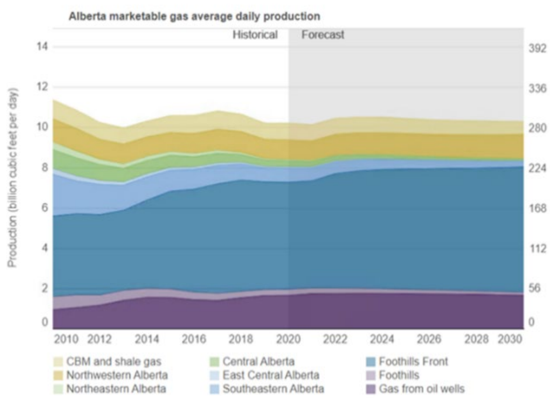
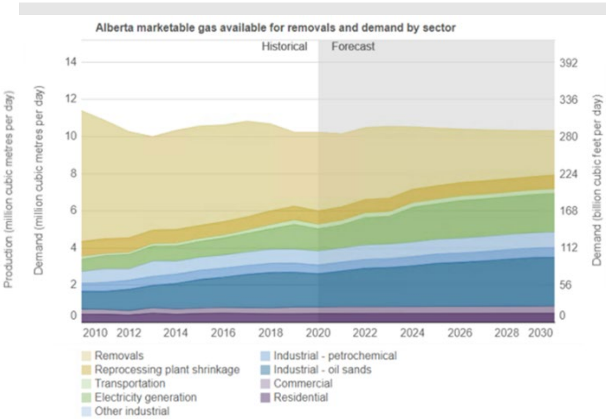
[13] Source: 2021 total installed capacity per "EDC Associates Ltd: 2021 Alberta Electric Energy Market Statistics" (March 2022).
[14] Source: 2031 total installed capacity based on AESO Reference Case per July 2021 Long Term Outlook presentation.
[15] "Alberta Energy Outlook" (June 2021), online: *Alberta Energy Regulator* < https://www.aer.ca/providing-information/data-and-reports/statistical-reports/st98>.



Source: AER.



Source: AER.

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 now 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[16].

*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 EIA reported global consumption of petroleum and liquid fuels grew by 5.22 million bbl/d in 2021, with a forecasted increase of 3.54 million bbl/d in 2022[17]. 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 reported production growth in 2021 and forecasts growth again in 2022, for both non-OPEC and OPEC+. With respect to non-OPEC production outlook, the EIA reported production growth of 0.8 million bbl/d in 2021 and forecasts growth of 3.3 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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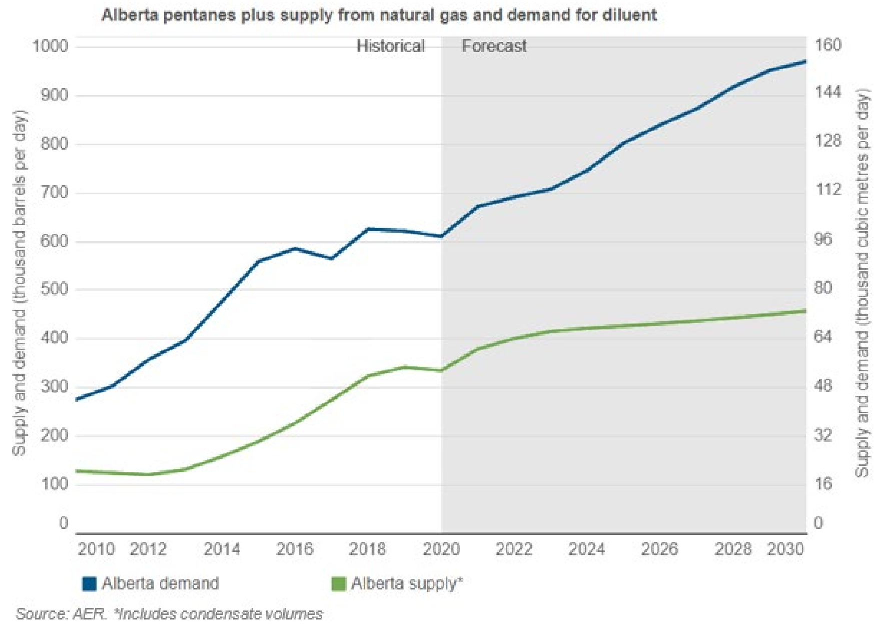
[16] *Ibid.*
[17] "Short Term Energy Outlook" (8 February 2022), online: *Energy Information Administration* <https://www.eia.gov/outlooks/steo/>.




***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 licenses 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 licenses 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 licenses 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.

*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.

## 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, licenses 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.

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 license. 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 licenses. 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 *Indian Oil and Gas Act* 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 First Nations 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. . On January 18, 2023 the British Columbia government and Blueberry River First Nation reached an agreement to allow them to move forward in a partnership approach to land, water and resource stewardship that ensures Blueberry River members can meaningfully exercise their Treaty 8 rights while at the same time providing stability and predictability for industry in the region. See "*Risk Factors – Risks Related to the Company – Indigenous Land Claims and Other Community Opposition*".

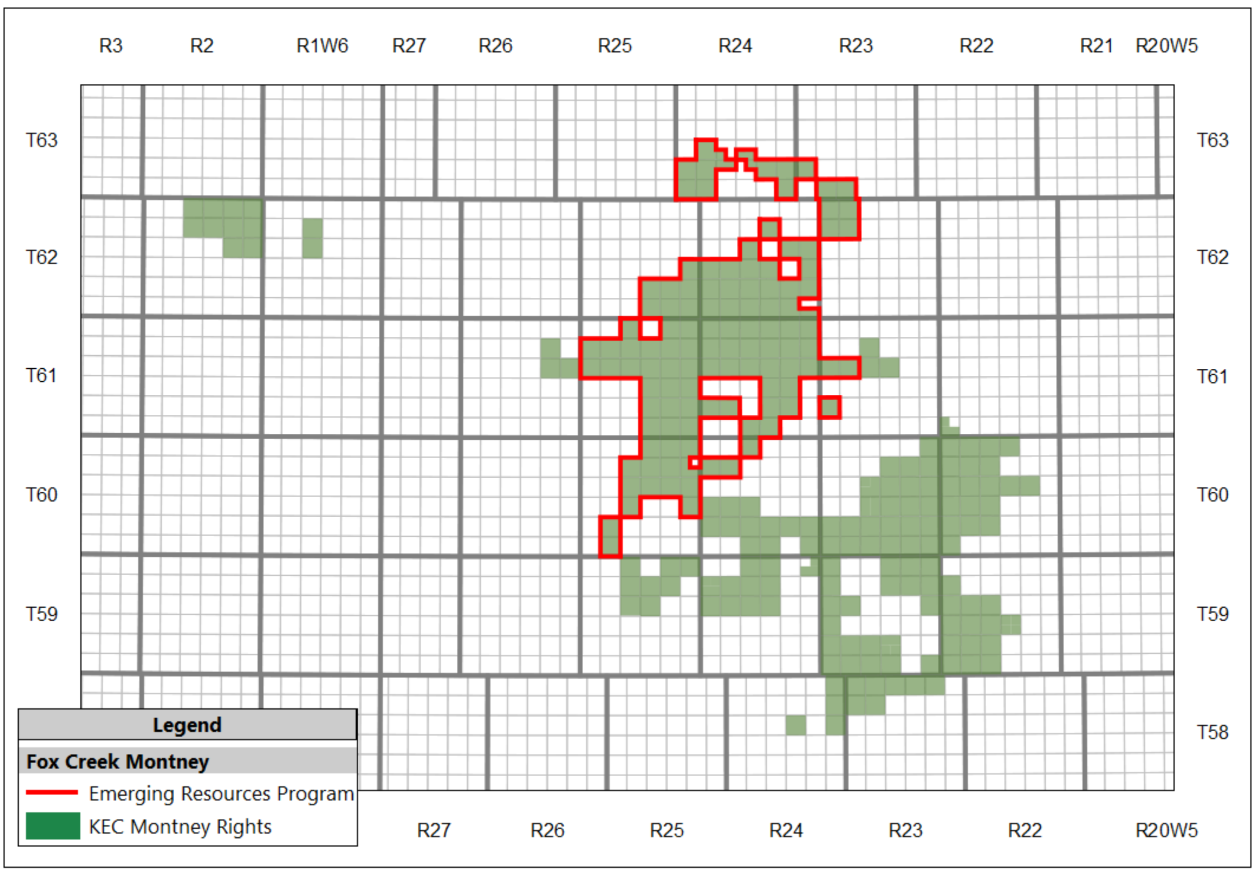
The outcome of negotiations between the Province of British Columbia and the Blueberry River First Nation is expected to be watched by other First Nations with treaties in Canada that are seeking greater influence over or to halt industrial development in their territories. The Province of British Columbia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

***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. Approximately 115 sections of the Fox Creek Montney rights within the Simonette Assets qualify for the benefits of this royalty program with the possibility of minor expansion in the future. The Fox Creek Montney rights held by the Company are shown on the map below, with the sections outlined in red being qualified for the Emerging Resource 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 licenses 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, such as greenhouse gas emissions, or when they arise from projects that are subject to federal jurisdiction, such as interprovincial transportation undertakings, including interprovincial pipelines and railways, species at risk act, 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. In 2022 the Alberta Court of Appeal released a decision finding the IAA to be unconstitutional, which has subsequently been appealed to the Supreme Court of Canada by the federal government.

On June 21, 2021, the *United Nations Declaration on the Rights of Indigenous Peoples Act* (“**UNDRIP Act**”) became law in Canada. The UNDRIP Act creates a roadmap for Government to work with Indigenous peoples to: develop an action plan to achieve the principles of the United Nations Declaration on the Rights of Indigenous Peoples ("**UNDRIP**"); align federal laws with UNDRIP; and prepare annual reports on progress. The UNDRIP Act requires that the action plan be developed as soon as possible and no later than by June 2023. In the absence of a published action plan, it is unclear what the practical consequences of this law will be.

*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 Alberta government has announced its intention to dissolve the Balancing Pool and reassign its responsibilities to other entities.

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.

***Liability Management Framework***

*Alberta*

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

The AB LMR Framework applies at all phases and throughout the life cycle of energy development and includes five key components: (a) the Licensee Capability Assessment System (“LCA”); (b) the Licensee Management Program (“LPA”), (c)the Inventory Reduction Program (“IRP”); (d) the Legacy and Post-closure Sites Program; (e) the Mandate of the Orphan Well Association.

Importantly, the AB LMF requires companies operating in Alberta's crude oil and natural gas industry to make mandatory annual minimum payments towards outstanding reclamation obligations. Although still evolving, the AB LMF is being implemented through, among other things, AER Directive 088 Liability Management Framework and amendments to existing AER Directives pursuant to which the AB LMR Program is currently administered. The reclamation annual spend targets came into effect on January 1, 2022 through the Inventory Reduction Program set out in Directive 088: Licensee Life-Cycle Management Directive ("**LLCM Directive**"). Among other things, the LLCM Directive states that all AER license 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. 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 through 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.

***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 development, 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, 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 licenses, 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 behavior 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 proposed power generation facility developments and electrical interconnections for power projects to determine if these proposed power facilities 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 stakeholders 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 behavior in Alberta's wholesale electricity market.

The AEPA evaluates wildlife and habitat risks of renewable projects, and reviews and approves industrial applications for gas-fired power projects. For renewable projects, the AEPA identifies and evaluates risks to wildlife and habitat, works with the project developer to mitigate risks, and provides a referral report to the AUC. For gas-fired power projects, the AEPA conducts an evaluation of the industrial application of the project, specifically potential impacts on soil, vegetation, surface water, wildlife and air quality. The AEPA also provides recommendations and approvals for industrial applications.

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 of 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.

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 the date of this AIF, the carbon levy pursuant to the GGPPA is $65 per tonne for 2023 and will increase by $15 per year up to $170 per tonne through 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. In December 2021 the federal government announced a suite of new initiatives to bring total methane emission reductions into the 40-45% range by 2025 compared with 2012 levels and that it is developing an approach to cut and cap oil and gas sector emissions of all greenhouse gases.

The Government of Canada has enacted the Multi-Sector Air Pollutants Regulation under the authority of the *Canadian Environmental Protection Act, 1999* (Canada). The Clean Fuel Standard 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 was published in late 2021 and came into force in June 2022, including: (1) Registration for primary suppliers, registered creators, foreign suppliers and carbon intensity contributors; (2) Applications for recognition of CO2e emission reduction projects; (3) Applications for approval of carbon intensity, and; (4) Compliance credit creation.

**Clean Electricity Regulations**

In 2022 the Government of Canada announced its Proposed Frame for the Clean Electricity Regulations ("CER"), part of a suite of federal measures to move Canada's electricity sector to net zero. The proposed CER applies to all electricity generating units that combust fossil fuels, have capacity above a yet-to-be-determined megawatt threshold, and offer electricity for sale onto a regulated electricity system. The proposed CER frame consists of: (1) A yet-to-be-determined emissions performance standard in the form of intensity (i.e. t/GWh) set at a near-zero value in line with direct emissions from well-performing, low-emitting generation such as geothermal or combined cycle natural gas with CCUS; (2) financial compliance requirements that require facilities with residual emissions below the performance standard, to either purchase offsets or pay an amount that corresponds to the federal carbon price applicable in that year; and (3) operational prohibitions when emissions performance exceeds the applicable standard over yet-to-be determined period of time. With respect to implementation, units commissioned in 2025 or after would be subject to current electricity sector policies (i.e. coal phase out, performance standards for natural gas, and carbon pricing) until January 1, 2035 after which the CER would replace those current electricity sector policies. Existing units (I.e. those in service before 2025) would become subject to the CER's emissions intensity performance standard on January 1, 2035 or at the end of their prescribed life(which may be a facility-specific terminal date determined by the federal government). The federal government expects to announce draft regulations, including further details on the proposed Performance Standards, in the first half of 2023.

**Oil and Gas Emissions Cap**

In 2022, the Government of Canada sought comments on implementing an Oil and Gas Emissions Cap in line with Canada's commitments outlined in its Emissions Reduction Plan ("ERP"). The ERP modeling outlines a pathway to meet Canada's 2030 GHG emissions target. The ERP modeling projects a contribution from the oil and gas industry of reducing emissions by 31% below 2005 levels in 2030. The design of the cap will take into account other regulations, such as the commitment to reduce oil and gas methane emissions by at least 75% by 3020. The Government of Canada published a discussion paper in 2022 focused on two potential regulatory options to cap and reduce oil and gas sector GHG emissions: (1) A cap-and—trade system (under the Canadian Environmental Protection Act) that sets a regulations time limit on emissions, including a national cap-and-trade system which would distribution allowances equal to the level of the cap; and (2) modification of the current carbon pricing approach under the Greenhouse Gas Pollution Pricing Act..

A cap-and-trade system would establish a total quota or cap of GHG emissions allowable for specific periods which declines over time in combination with a trading system which would distribute allowances equal to the level of the cap. At the end of the compliance period, every facility that operated during the period would need to remit one allowance for every tonne of emissions it emitted. Oil and gas facilities that have a surplus of allowances can trade them on an emissions trading market. The total number of allowances allocated would decline over time. Allocation of allowances would be partially or fully auctioned to facilities. The second option of modifying the pollution pricing benchmark requirements is intended to incent further reductions in emissions from the oil and gas sector in line with oil and gas sector emission cap trajectory. This includes the review, and if necessary, revision of, the carbon price for the oil and gas sector and may include the restriction of trading of emissions credits or allowances between the oil and gas sector and other sectors in the pollution pricing systems. The federal government has committed to engaging the provinces and territories and Indigenous organizations with respect to the planned review of existing pricing benchmark requirements.

Government of Canada direction on the Oil and Gas Cap is expected in 2023.

**Methane Emissions Reductions**

To comply with *Canada's methane regulations*, Canada's oil and gas industry must adopt practices that prevent gas from being intentionally vented into the air during oil and gas production. As such, the Government of Canada has announced regulations designed to help reduce the sector's methane emissions by 40 to 45 percent by 2025, relative to 2012 emissions. In alignment with this mandate, the Government of Alberta committed to a methane emissions reduction target for the oil and gas sector, using a combination of policy tools to achieve the province's 45% methane reduction target by 2025 including regulatory requirements, market-based programs, and investments in technology and innovation.

Alberta is on track to meet its methane emissions reduction target by 2025.

Under the Government of Canada's *Greenhouse Gas Pollution Pricing Act* ("GGPPA") any province or territory can design its own pricing system tailored to local needs, or can choose the federal pricing system. The federal government sets minimum national stringency standards ("Federal Benchmark"), that all systems must meet to ensure they are comparable and effective in reducing greenhouse gas emissions. If a province or territory decides not to price pollution or proposes a system that does not meet these standards, the federal system is put in place.

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 two per cent each year beginning in 2023. 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 $50 per tonne of $CO_2E$ in 2022).

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.

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.

In 2022, TIER was updated to create sequestration credits and capture recognition tonnes. Sequestration credits may be retired to meet TIER compliance obligations as well as may be used under the Clean Fuel Regulations. An emission offset may be converted into a sequestration credit if it meets certain criteria, including: (1) the emissions offset having been created from a geological CCUS project; (2) the sequestration must have occurred in 2022 or later; and (3) the carbon dioxide that was geologically sequestered must have been captured at a large emitter or opted-in facility regulated by TIER. Sequestration credits may only be used for compliance for a period of five years after the year they are generated. Capture recognition tonnes will enable large emitters and opt-in facilities to reduce sequestered emissions from their total regulated emissions at carbon capture sites.

A sequestration credit can be converted into a capture recognition tonne, provided (1) the carbon dioxide that was geologically sequestered for the associated emission offset was captured at the facility applying to convert the sequestration credit and (2) the sequestration occurred in 2023 or later.

## 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 or other Company securities 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

Overall, the Company faces operating risks related to business interruption, project construction, production, drilling, completions, marketing, power generation, hydrogen production and carbon dioxide management. Financial and accounting risks include risks related to land, reserves and resources, commodity prices, counterparties, insurance and access to capital. Environmental risks include those risks associated with climate change and other environmental issues. Social risks include those risks related to stakeholders, employees, contractors, suppliers and investor relations. There are also governance and reputational risks, all as more fully described below.

***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 renewable 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.

A number of 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, supply chain delays, 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 licenses 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 Complete and/or 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 significant acquisitions and dispositions from time to time. 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.

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. In addition, 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.

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. Rapid growth through multiple acquisition also exposes the Company to the risks associated with inadequate financial controls and reporting.

***Global Economic and Financial Conditions and Commodity Prices***

Recent market events and conditions 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.

***Foreign Exchange Rates***

The Company sells a significant portion of its production in the U.S. and volatility in foreign exchange rates could result in a decrease in cash returned to Canadian dollars. In addition, the Company may be exposed to changes in the Canadian dollar in relation to foreign-currency-denominated equipment purchases for its upstream or green energy projects which could result in a significant increase in the cost to construct these projects. Overall the change in foreign exchange rates may have a negative impact on the Company’s financial results.

### *Russia Ukraine Conflict*

In February 2022, Russian military forces invaded Ukraine. The outcome of the conflict is uncertain and is likely to have wide-ranging consequences on the stability of the region and the global economy. Certain countries have imposed financial and trade sanctions against Russia and the situation continues to evolve. Ocean shipments of oil and gas and other petroleum products have been impacted by caps on oil price for shipments originating from Russia along with military actions including blockades and attacks. The conflict has caused stress on international banking systems leading to the instability of some institutions and increased lending interest rates and/or tighter lending qualification requirements. There is also the heightened risk of cyber-security issues. Due to the foregoing factors, the Company’s ability to reliably predict oil and natural gas prices has been impaired and the supply of materials needed to implement the Company’s business plan is volatile. The extent and direction of the current Russia-Ukraine conflict and related international action cannot be accurately predicted at this time. The long-term impacts of the conflict and the sanctions imposed on Russia remain uncertain.

### *Licenses and Permits*

Kiwetinohk holds permits to operate from various regulators that are required to conduct its business. The licenses generally require that Kiwetinohk conduct specific aspects of its business to a standard of care. An accident or an inspection which reveals a failure to meet the standard of care could result in fines and/or suspension of operating licenses. In some cases, Kiwetinohk could lose one or more of its licenses.

Moreover, there is no assurance that Kiwetinohk will be able to obtain all the necessary licenses and permits required. The Company does not currently hold all the approvals, licenses 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 licenses, 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) and other pandemics***

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.

While the effects of the COVID-19 pandemic appear to be lessening, the extent to which COVID-19 may continue to, or other pandemics may, impact Kiwetinohk is uncertain. It remains possible that COVID-19 or other pandemics 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. Kiwetinohk's workforce and the workers available to Kiwetinohk may be reduced by widespread communicable disease, such as COVID-19. Kiwetinohk may lose the services of one or more of its leadership personnel as a result of such an event. Suppliers and service providers may encounter a reduced capacity to provide Kiwetinohk with their products due to widespread communicable disease.

***Market Constraints and Business Interruption***

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 (a specific example being COVID-19 as discussed above), changing political policy in energy-producing regions, or other geopolitical events and circumstances. These and other factors can cause an over or undersupply 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.

Kiwetinohk's petroleum products are shipped to markets on a few pipelines, with the majority of gas transported on the Alliance Pipeline and the majority of liquids transported on the Pembina's Peace Pipeline. If any of the third-party transportation systems 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. Risks may occur for reasons such as a party on either the Alliance Pipeline or the Pembina's Peace Pipeline delivers off-specification products into the pipeline causing the pipeline service provider to curtail inputs while the contaminated fluids in the pipeline are removed or the pipeline could form a leak causing the pipeline service provider to shut down while the leak is repaired and, perhaps, limit throughput while the pipeline is inspected.

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. Natural disasters or actions by governments such as export and or import restrictions may affect access to equipment and materials needed for Kiwetinohk's business or markets or prices for the Company's products.

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.

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. 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.

As renewable output from other solar and wind projects are added to the general power grids to which the Company contributes, electricity grid instability may develop due to the inherent volatility of renewable power generation, resulting in interruptions to the operation of the Company's renewable power projects.

***Industry Shortages***

The Company believes that the energy industry is undergoing rapid transition to an increased fraction of total primary energy arising from renewable solar and wind. In addition, there is a shift toward CCUS with fossil fuel-fired power and a general shift away from coal toward natural gas use in power generation. This may cause shortages that adversely affect Kiwetinohk, including:

(a) shortages of skilled workers, including executive, technical and operating personnel;

(b) shortages of equipment and materials required by the oil and gas sector, as manufacturers and suppliers withdraw from the industry; and

(c) shortages of equipment and materials required by the carbon capture, power generation and hydrogen manufacturing sectors as those sectors ramp up capacity.

As the sectors that Kiwetinohk participates in evolve, projects with increased complexity or novelty may be proposed by sector participants. This may result in reduced capacity of regulators to consider and approve projects in a timely manner.

***Hydrogen Production***

Kiwetinohk aspires to enter the hydrogen production business. At this time hydrogen manufacture and distribution is limited to closed access systems that connect producers with markets. There is no assurance that an open access hydrogen market will evolve in Alberta or that it will be attractive to Kiwetinohk's primary energy locations and hydrogen manufacturing opportunities.

***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 represents a substantial risk to the value of the Company over the long term.

### *Possible Shortage of Fresh Water and Surface and Groundwater Licenses*

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 fresh water use as a hydraulic fracture fluid. These alternatives may include deep potable or brackish groundwater, 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.

Climate change induced drought could impact the year-round availability and associated costs of fresh water for Company operations such as drilling fluid, completions fluid and power or hydrogen plant cooling water. Furthermore, there can be no assurance that the Company's governmental licenses to withdraw water will not be rescinded or that additional conditions will not be added to these licenses. 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 licenses for additional water withdrawal, and there can be no assurance that these licenses will be granted on terms favorable to the Company, or at all, or that such additional water will in fact be available to divert under such licenses.

### *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.

Kiwetinohk operations could be affected by an unexpected event such as encountering a very high pressure or very high permeability zone while drilling leading to a well control situation. 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. The Company develops hydrocarbon-prone resource rocks in search of natural gas, natural gas liquids and oil, all of which are flammable.

The Company’s oil and gas operations include some extreme and rare conditions for the oil and gas industry. These deep resources exist at high pressure and often require higher pressures to fracture stimulate the rock. Weighted drilling and completion fluids are required to counter the high pressure of the resource. The wells are deep, requiring drilling rigs with high lift capacity. These extreme operating conditions create risks of failures from pipeline or well control systems or other equipment beyond the risk of most conventional oil and gas operations.

The fluid used for fracturing wells undergoing hydraulic fracture stimulation may communicate with other wells causing damage to the well casing, liner or the wellhead and potential loss of well control. Fluid from newly added wells may fill pre-existing wells with fracture fluid and thereby impair the production of the pre-existing well. Further, the pre-existing well may drain some of the injected fluid from the new well, reducing the pressure of the area stimulated by the new well and thereby leading to an impairment of productivity of the new well. The equipment used to hydraulically fracture wells is often operated at very high pressures, pumping at times very corrosive or erosive slurries. Higher pressure, corrosivity and erosivity all contribute to a higher risk of piping failure.

***Data Risks and Significant Factors or Uncertainties Affecting Reserves Data***

Kiwetinohk relies on historical data to evaluate the effectiveness of its activities. Data from historical activities may be erroneous or inadequate and conclusions drawn from the analysis may be in error leading to inaccurate predictions and result in activities that are not as profitable as originally predicted. Kiwetinohk may drill, complete or tie in its wells in a way that yields less than maximum value achievable in the development of its resources.

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".

The flow of substances contained in tight or shale resource rock to the hydraulically induced fractures and to the wells is not well understood. Mathematical models of the physics of the flow of fluids from any point in a resource to a well were developed for conventional oil and gas. These models are generally less reliable for tight and shale resources that have been developed with horizontal wells with multiple hydraulic fracture stimulations along the lateral length. Well performance statistics generally suggest that the performance of wells is affected by wells that are drilled nearby before or after the predicted well. These uncertainties generally make prediction of fields with new wells unreliable. If new wells are expected to add a significant amount of production, then forecasts for the new entity are rendered unreliable.

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.

***Hydraulic Fracturing and Earthquakes***

The frequency and magnitude of seismic activity in certain zones and/or regions has been correlated to hydraulic fracture stimulation activity. Seismic activity, natural or induced by human activity, has the potential to crimp or shear casing liners and impair wellbore access beyond the depth where it occurs. Such impairment reduces the area that can be effectively drained by a well and the recovery of that well and, likely, the recovery from the whole development.

Kiwetinohk is required to suspend hydraulic fracturing operations if a seismic event above a prescribed magnitude occurs near a hydraulic fracturing operation. 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 License***

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.

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, and to ensure the Company is effective at identifying and addressing social risks and opportunities. 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.

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. To access its lands by permanent or temporary road and to connect its operations by road, power lines and pipelines the Company may require the approval of multiple parties including regulators, local governments, Indigenous groups and owners of existing roads and pipeline and power line rights of way. These parties may be in a position to delay or prevent access. Further, access to Company lands or assets may be obstructed or impaired by demonstrators and the Company's assets and construction sites have exposure to theft and vandalism.

The Company may also be subject to workplace violence, insider trading, fatality, harassment, substance abuse, ethics scandal, code of conduct violation or corruption allegation which would be damaging to the Company's reputation. The Company also engages and contracts with various vendors or stakeholders who may have a dispute, litigation or damaging public event that by association would impact the Company's reputation. There may be a perception of greenwashing or cultural appropriation by the Company in the industry, community or with investors which may create misleading claims and damage to the Company's reputation and ability to engage with stakeholders.

***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***

Kiwetinohk's resources are held in leases, mostly owned by Alberta. There is a risk that the Government imposes the strictest interpretation of land tenure regulations and terminates a high percentage of leases on expiry. The leases have defined terms and conditions upon which they are granted and renewed. The Government has the power to unilaterally change the royalty charged or the conditions of renewal. Kiwetinohk is at risk of loss of value due to revision in royalty or lease renewal provisions. Kiwetinohk also risks losing leases if they are not drilled and brought on to production within the terms of the relevant lease. Kiwetinohk may fail to bring leases on to production because limited capital may be allocated to other higher return priorities or because surface access to a point where wells can be drilled to access a lease may be impaired by surface conditions, such as swamps, steep valleys, or there may be protected species access restrictions.

Furthermore, on the freehold side, as the Company develops its land positions, it may be required to pay offset royalties to owners of adjacent land without wells. 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 alternatively the Company may 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. Certain insurance may become unavailable or available only for reduced amounts of coverage, in particular, insurance for assets emitting greenhouse gases. 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.

As carbon accounting rules and carbon emissions penalties evolve, distributed small-scale use of hydrocarbon-based fuels may become very costly, which may motivate the discontinued use of hydrocarbon-based fuels. This evolution, if it occurs, may severely reduce the hydrocarbon-production market to large consumers that have CCUS capability.

### *Access to Capital 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 by borrowing or the issuance and future equity issuances. The Company's ability to borrow or issue securities is dependent upon, among other factors, the overall state of capital markets and lender/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. Although the Company's business plan is designed to facilitate an economic transition to low-emissions, reliable, dispatchable, affordable energy for consumers, large segments of capital markets may not accept one or more elements, especially gas-fired power, posing a risk to financing the business plan.

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. Additionally, the Company's envisioned business will deal in commodities: oil, natural gas liquids, condensate, natural gas, electricity, carbon dioxide, and hydrogen. There is a risk that adverse commodity price cycles will be intense enough or long enough in duration that the Company's short-term goals cannot be met or that investors lose confidence in the Company's business plan as it is communicated to shareholders.

### *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. Additionally, the Company needs to maintain various covenants in its credit facility in order to avoid such actions as a demand for immediate repayment, reduction in borrowing capacity or further credit not being available.

### *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 and Succession Planning*

Due to its small size and broad scope of business, the Company is heavily reliant on key personnel. Loss of the services of any of these personnel without proper succession planning may make the Company, for a period of time, unable to conduct its business to the standard expected by regulators, lenders and investors.

Additionally, the novelty of some aspects of the Company's business (e.g., hydrogen manufacture, carbon capture) could leave Kiwetinohk exposed to risks associated with a lack of experienced personnel or ability to successfully plan for succession. The dearth of experience may increase the risk of equipment problems, downtime and safety incidents.

Further, 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 and power generation 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.

***Governance***

An individual Board member resignation or executive departure could leave the Company without adequate skills on the Board until a suitable replacement is found or, depending on the circumstances, create investor confidence risks.

If the Company grows rapidly, there may be risks and pressures on its internal systems and controls. Without adequate oversight and direction from the Board around audit, whistleblower, safety, code of conduct, compensation and ESG there could be adverse impacts on the business, operations or prospects.

***Indigenous Rights 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, licenses 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 ability of the Company to access land, develop and operate its business may be subject to general social opposition, negative sentiment or litigation which may result in delays or restrictions on the ability to advance through the environmental consultative process.

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.

***Climate Change Related Risks***

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 such as wildfires and overland flooding.

Climate change could lead to environmental impacts such as droughts and floods (and secondary impacts such as forest and prairie fires, reduced agricultural production capacity, habitat destruction and threats to species) in the Company’s areas of operation which could result in governments and regulators imposing new restrictions on Company activities out of concern for environmental protection. Climate change could adversely affect Kiwetinohk's ability to reclaim well, facility, road, pipeline and seismic line disturbances with native vegetation species as regulations require.

The cost of shipping the Company's products may rise due to an increased cost of the associated energy caused by carbon taxes or the conversion of petroleum to clean energy and the requirement for new infrastructure for shipping. Similarly, the cost of mobile service equipment such as drilling rigs, hydraulic fracture stimulation equipment and trucks for hauling equipment and services could rise significantly due to carbon taxes or increased cost of new equipment with electric or hydrogen-fueled engines. Delays or slow progress in transitioning energy systems on a national and global level may result in increased time pressure in the future compounding the equipment and material supply and shipping cost issues listed above.

In addition to climate policy risk, the industry faces physical risks attributable to a changing climate. Access to Company places of work and to Company assets may be impaired by a regional disaster. Facilities such as oil and gas processing facilities, wells, pipelines, power generation facilities (of any type) and power transmission lines owned by the Company, or owned by others but in the value chain for Company activities, may be damaged or incapacitated by a regional disaster such as a windstorm or blizzard, flood, forest or prairie fire, earthquake or lightning strike. People may be injured or their health may be damaged by such an event. Floods, storms and fires may make roads used by the Company impassable, trapping road users along dead-end roads. 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 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.

***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. 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, extremely 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.

***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, including hydraulic fracturing, 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, including hydraulic fracturing could also reduce the amount of oil, NGL and natural gas that the Company is ultimately able to produce from its reserves.

Development of the Alberta oil sands, oil and natural gas development and transportation, hydraulic fracturing and fossil fuels have figured prominently in recent political, media, investor 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 in oil sands developments may directly or indirectly reduce the profitability of the Company's current projects and/or the viability of existing and future projects in the Alberta oil sands and reduce the demand for and pricing of the oil, NGL and natural gas the Company produces. The Company's corporate reputation may be negatively affected by the negative public perception and public protests against oil and natural gas development, water and land usage, transportation and hydraulic fracturing. Increased stigmatization of the oil and natural gas industry, including hydraulic fracturing, may result in increased shareholder concern or negative shareholder feedback, reduce the market for the Company's Common Shares or the availability of financing to the Company or expose the Company to litigation.

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 current and future economic or political conditions.

Kiwetinohk's business plans and aspirations are built on the premise that markets require energy in a form that can be used with reduced associated emissions of GHGs relative to the current situation. Fossil fuel energy is currently being supplied to meet much of these energy needs. In many cases, regulation penalizing the emission of GHGs is required to make profitable the required replacement of existing high-emissions fossil fuel infrastructure. There is a risk that government policies will be insufficient or be imposed too late for Kiwetinohk to attain profitable opportunities as currently aspired.

***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 identified wildlife. The Company has built, and plans to build, facilities in areas inhabited by protected species. There is a risk that the Company's activities will be seen to adversely affect protected species, leading to an inability to access planned facility sites or, if already built, some kind of restriction on operations.

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 profitability of the Company's envisioned business depends on government-imposed financial instruments such as carbon taxes and carbon tax credits. Any of these financial instruments may be changed by the relevant government and such changes may adversely affect the profitability of some or all of the Company's business. Further, in this regard, Kiwetinohk's aspired markets are concentrated in Alberta, Canada, and fiscal changes in that jurisdiction would be expected to affect Kiwetinohk more profoundly than Kiwetinohk would be affected if its markets were distributed across more jurisdictions. Government grants may affect the competitiveness of the Company's business plan. Governments are allocating grants and tax credits to established companies that are making transition investments such as CCUS. The Company's competitive position may be compromised by not meeting the criteria for Government subsidy.

The Government of Canada has disclosed a plan to raise carbon taxes to $CDN 170 per tonne by 2030. There is a risk that accounting for GHG releases and the rate of carbon taxation and the level it reaches will be changed from time to time, creating an economic environment of uncertainty. This risk is further complicated by the dependency of Canadian hydrocarbon energy producers on exports to the U.S. and the uncertainty as to how the U.S. will regulate GHG emissions related to domestic and Canadian production.

### *Taxes*

Governments may impose taxes or other conditions that may result in increased costs on portions of the value chains that form Kiwetinohk's business. This risk may be accentuated as the economy adjusts to provide energy with reduced GHG emissions and governments and regulators in turn adopt new taxation and other regulatory regimes potentially applicable to Kiwetinohk's business.

### *Tax Horizon*

The Company did not pay any income taxes during the year ended December 31, 2021. The acquisitions that were completed by the Company during 2021 resulted in a significant increase to tax pools and as at December 31, 2022, the Company had approximately $777 million of tax pools and losses available. It is expected, based upon current legislation, and estimates of future taxable income, tax pools and capital expenditures, that no significant cash income taxes will be paid by the Company in 2023. A higher (lower) level of capital expenditures than those currently contemplated, decreases (increases) in production rates, decreases (increases) in commodity price assumptions or further additional acquisitions (dispositions), could further extend (reduce) the estimated tax horizon. The anticipated future cash tax horizon of the Company is subject to risks, uncertainties and other factors that could cause the Company's cash future tax horizon to occur sooner than our current projection of approximately two years on owned assets. In particular, our anticipated future cash tax horizon is subject to risks pertaining to changes in our capital expenditures, operations, growth, capital expenditures, asset base, acquisitions, corporate structure or changes to tax legislation, regulations or interpretations, and our growth. A higher (lower) level of capital expenditures than those currently contemplated, decreases (increases) in production rates, decreases (increases) in commodity price assumptions or further additional acquisitions (dispositions), could further extend (reduce) the estimated tax horizon. In the event we become cash taxable sooner than projected or we are unable to lengthen the cash tax horizon through the acquisition and development of additional growth projects and related tax pools. Our cash available for distribution and our dividend (should we determine the future to make distributions or pay dividends) could decrease, which would in turn have a MAE on the value of our common shares. See “The Company has no plans to pay dividends.

***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 the 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 Construction and Execution***

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. The Company may fail to secure grid access and/or regulatory approval for any of its power projects. Due to 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. Estimates of energy production and price for any of its projects may be proven to be in error or climate change may lead to changes in weather patterns that negatively affect the output of the Company’s renewable facilities.

The Company may have difficulty accessing power grid capacity for its planned power generation projects. Kiwetinohk plans to enter the power generation business with a focus on Alberta. In Alberta, grid power transmission is managed by the AESO, which oversees the connection of projects to the power grid. In many cases, the power grid has inadequate capacity for new projects, especially large projects and especially projects in areas with a lot of proposed new power such as southern Alberta where a surge of investment in new power projects is occurring.

The Company believes that there is a need for low-cost, low-emissions, reliable and dispatchable power generation. The peaker power plants that the Company aspires to build (and calls "Firm Renewable") are dispatchable but, due to their intermittent and volatile output and their lower efficiency than NGCCs, they generate higher cost power and, as discussed elsewhere, coupled CCUS is likely less effective at capturing GHG emissions. The Company also believes that clean power, specifically solar and wind, is most desirable from a climate change point of view. However, solar and wind power can also cause grid instability. As gas-fired power may be needed to supplement solar and wind power, power grids are likely to be overbuilt with total capacity leading to curtailed-output and operation of some of the baseload gas-fired power which may add to the total cost of power. Any type of power project may be overbuilt leading to oversupply of power addressing that market (renewable baseload, gas-fired baseload, Firm Renewable) and a reduction in price received.

The Company is seeking approval to build deep brine aquifer carbon dioxide storage in association with its CCUS projects. The Alberta Government is in the process of allocating storage capacity by region. The Company cannot be assured at this time that it will be successful in securing storage capacity.

***Transportation and Processing Commitments***

The Company presently has more gas capacity contracted for transportation and for processing than it produces. The Company has been able to buy natural gas from other producers to make up its take-or-pay obligations. In the future, the Company may be subject to a loss due to the inability to fill its contracted pipeline and processing capacity at break-even or better gas prices.

***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.

### *Effluent*

Effluent from Kiwetinohk's producing wells is generally gathered with a network of pipelines that have been installed through swamp and forest land. The pipelines contain the components produced from the wells including natural gas (possibly containing hydrogen sulfide), natural gas liquids, oil and brine. Pipeline failure due to corrosion or construction activity could cause a release of these fluids. The ability to clean up a release and the environmental damage a release might cause vary with the conditions of the site and the nature of the fluid.

### *Reduced Recovery Factor*

The Company holds resources that contain liquids rich natural gas. As the gas flows through the resource rock toward the lower pressure of the well, liquid hydrocarbons may condense from the gas phase and form an impediment to flow for the gas. More liquids may condense in the wellbore as the gas cools as it flows to the surface. From either or both causes, liquids may accumulate in the wellbore and impair production from the well. Artificial lift measures may be of limited effectiveness in removing the liquid accumulation in the well and in the resource rock such that the rate of decline of the wells accelerates as the well matures. There is a risk that the net result of the liquids content of the Company's gas resource is a significant overall reduction in recovery factor relative to lean gas recovery factors in similar resource rock. There is a further risk, due to the complexity of this situation, of the Company and its independent reserve evaluator inaccurately estimating the production of wells and recovery from the resource.

### *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 2022 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 operates 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. There can be no assurance that the Company will be able to raise external financing on commercial attractive terms or at all.

The Company has outstanding debt. Increases in interest rates could divert cash flow from operations to interest payments detracting from the Company's ability to fund its capital program and return cash to shareholders.

Inflation in the cost of goods and services that the Company buys could rise disproportionately to the inflation in the price of the products that the Company sells, resulting in lower inflation-adjusted funds from operations. There is also a risk that debt, equity and partnership financing may become unavailable or more restricted in scope or higher cost for companies producing fossil fuels or emitting greenhouse gases.

***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***

Kiwetinohk's business value, both present and envisioned, is largely underpinned by liquids rich natural gas resources. The Company estimates recoverable volumes of natural gas from time and uses the estimates to model future financial performance of the Company. Internal ultimate recovery estimates are augmented by shorter term independent reserve evaluations that are compliant with Canadian standards. In all cases, the estimate of future recovery is at risk due to the significant judgment and decision-making based on available reserve estimates on future uncertain conditions such as commodity prices, royalties and access to and operating conditions of gas gathering and processing systems. There is also a risk that the Company will be in error on forecast information due to natural disasters, other unpredictable events or delays and costs imposed by third parties. The physics of storage and flow of hydrocarbons in very fine-grained rocks, such as Kiwetinohk's Montney and Duvernay resources, and the physics of hydraulic fracture stimulation are not well understood and subject to judgment, which may result in reduced recovery, production and/or revenue.

The reserves information herein represents estimates prepared by McDaniel 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 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 for 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.

### *Counter-Party Related Risks*

The Company may be exposed to third-party credit risk through its contractual arrangements with its current or future commodity purchasers, joint interest partners, banks, or hedging counterparties. 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*

The Company has a limited “public float” of Common Shares available for trading. The distribution of share ownership may be an impediment to professionally managed funds interest in acquiring Common Shares. ARC and Luminus beneficially own or control 27,539,624 Common Shares and 5,202,334 Common Shares, respectively, which in the aggregate represent approximately 62.3% and 11.8%, 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.

### *Small Public Float and Limited Liquidity*

The liquidity of the Company’s Common Shares in the market may be constrained for as long as ARC and Luminus continue to hold a significant investment position. A lack of liquidity in the Common Shares may restrict the trading price and as a result the trading of a relatively small volume of Common Shares may disproportionately influence the price of those Common Shares in either direction. For example, the price for Common Shares could decline significantly if a large number of Common Shares were to be sold in the market without a commensurate demand. As a result, the trading price of Common Shares may experience substantial volatility and investors may not be able to freely exit or enter into trading positions in the Company’s Common Shares.

### *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. There are risks for legal actions against fossil fuel producers by parties claiming damages due to climate change. 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*

The Company has had a significant amount of growth and change in the past year and has built out internal controls to provide reliable and accurate financial reporting and prevent fraud. Due to the size of the Company, an identified failure of internal controls may reduce investor confidence in the market and result in lower share price or inability to raise money. Issues associated with the failure to maintain adequate internal controls may also result in a failure to meet regulatory filing deadlines, which could have a compounding effect in terms of the erosion of investor confidence.

### *Cyber Security Risks*

The Company is subject to risks of computer-related fraud, piracy and sabotage. 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 has 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*

The Government of Alberta is currently in the process of implementing an updated 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 fully certain how the new framework will affect the Company going forward. While components of the new framework related to transfer applications have now been implemented through AER Directive 088: Licensee Life-Cycle Management, the entirety of the new framework is yet to be fully implemented. Asset retirement obligations assumed by the Company as part of acquisition transactions could exceed the amount considered in the determination of the purchase price contributing to a loss of value for Kiwetinohk.

Changes to the Government of Alberta's various liability management programs and the ratio requirements for deemed assets to deemed liabilities may result in the requirement for security to be posted by the Company in the future. Bulletin 2016-16 and Directive 067 may impact acquisitions and dispositions by oil and gas companies, including the Company. Given the recent release of liability management framework policy components and the ongoing implementation 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.

***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, 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 and Regulatory Pressures to Adopt New Technologies***

Technology for energy transformation and transportation is changing and evolving rapidly. As the energy transition progresses and new processes replace established ones, there is a risk that Kiwetinohk selects and builds equipment using a new process that is made obsolete and uncompetitive before its economic life is reached.

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, either through competitive pressures or through government regulation. 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, licenses 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 license. 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, licenses, 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 licenses, 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 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 as evaluated in the 2022 Reserves Report.

The 2022 Reserves Report has 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 2022 Reserves Report. The terms “heavy crude oil” and “heavy oil” have been used interchangeably within the meaning of the reserves definitions contained in NI 51-101.

**Disclosure of Reserves Data**

The reserves data set forth in this AIF is based upon the 2022 Reserves Report prepared in accordance with the standards contained in COGEH and the reserves definitions contained in NI 51-101 and CSA 51-

324. The 2022 Reserves Report, from which the data below is derived, has a preparation date of March 7, 2023 and evaluated the reserves attributable to Kiwetinohk as at December 31, 2022.

The reserves data summarizes the shale gas, NGL, tight oil and heavy crude oil reserves of the Company, 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 are in the provinces of Alberta.

The present value of future net revenue before and after income taxes has been estimated by McDaniel. 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 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 crude oil and natural gas properties reflects the tax burden of the properties on a stand-alone basis. It does not provide an estimate of the value of the Company as a business entity, which may be significantly different.

All evaluations of future net revenue contained in the 2022 Reserves Report 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 represent the fair market value of those reserves. There is no assurance that the forecast price and cost assumptions contained in the 2022 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 came from Kiwetinohk and government sources. In instances where recent production numbers were not publicly available, they were provided by the Company. The Company also provided McDaniel with other required information, such as operating statements, land data, logs from recently drilled wells and field development plans. McDaniel incorporated all this data into its analysis in accordance with standards set out in the COGEH. The standards in the COGEH require McDaniel 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.

**2022 Reserves Report**

The tables below summarize the data contained in the 2022 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 three consultant average forecast prices (dated January 1, 2023), as set forth below.

## *Summary of Reserves (Forecast Prices and Costs)*

*Summary of Reserves*
*As of December 31, 2022 — Forecast Prices and Costs*

| | Heavy Oil | | Tight Oil | |
|---|---|---|---|---|
| | Gross (1) | Net (2) | Gross (1) | Net (2) |
| **Reserves Category** | **Mbbl** | **Mbbl** | **Mbbl** | **Mbbl** |
| Proved | | | | |
| Developed Producing | 0.0 | 0.0 | 1,279.7 | 997.2 |
| Developed Non-Producing | 0.0 | 0.0 | 0.0 | 0.0 |
| Undeveloped | 0.0 | 0.0 | 0.0 | 0.0 |
| **Total Proved (4)** | **0.0** | **0.0** | **1,279.7** | **997.2** |
| **Total Probable** | **0.0** | **0.0** | **254.4** | **190.2** |
| **Total Proved + Probable (4)** | **0.0** | **0.0** | **1,534.1** | **1,187.4** |

| | Shale Gas | | Natural Gas Liquids (3) | | Total | |
|---|---|---|---|---|---|---|
| | Gross (1) | Net (2) | Gross (1) | Net (2) | Gross (1) | Net (2) |
| **Reserves Category** | **MMcf** | **MMcf** | **MMcf** | **MMcf** | **MBOE** | **MBOE** |
| Proved | | | | | | |
| Developed Producing | 130,149.7 | 118,376.2 | 17,428.1 | 13,499.2 | 40,399.4 | 34,225.8 |
| Developed Non-Producing | 1,337.8 | 1,233.8 | 190.2 | 160.5 | 413.1 | 366.1 |
| Undeveloped | 283,176.1 | 256,781.9 | 37,535.3 | 31,300.6 | 84,731.3 | 74,097.6 |
| **Total Proved (4)** | **414,663.6** | **376,391.9** | **55,153.5** | **44,960.3** | **125,543.8** | **108,689.5** |
| **Total Probable** | **313,825.6** | **272,539.9** | **36,365.1** | **27,051.4** | **88,923.7** | **72,664.9** |
| **Total Proved + Probable (4)** | **728,489.2** | **648,931.8** | **91,518.6** | **72,011.7** | **214,467.6** | **181,354.4** |

**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 32% and pentanes plus represents 3% on a volume basis for Total Proved reserves, and 31% condensate and 3% pentanes plus on a volume basis for Total Proved Plus Probable 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 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 Dec 31, 2022 – Forecast Prices and Costs(1)*

| **Reserves Category** | **@0.0% M$(2)** | **@5.00% M$(2)** | **@10.00% M$(2)** | **@15.00% M$(2)** | **@20.00% M$(2)** | **Unit Value Before Tax (1) @10.00% (1) ($/BOE)** |
|---|---|---|---|---|---|---|
| Proved | | | | | | |
| Developed Producing | 942,527.8 | 846,280.8 | 734,748.5 | 648,559.0 | 583,542.2 | 21.47 |
| Developed Non-Producing | 13,658.6 | 10,450.4 | 8,405.9 | 7,027.1 | 6,043.8 | 22.96 |
| Undeveloped | 1,799,176.6 | 1,197,881.3 | 839,190.1 | 609,022.0 | 452,337.2 | 11.33 |
| **Total Proved (3)** | **2,755,363.0** | **2,054,612.5** | **1,582,344.5** | **1,264,608.0** | **1,041,923.1** | **14.56** |
| **Total Probable** | **2,452,470.7** | **1,444,970.1** | **956,454.0** | **686,957.9** | **522,972.1** | **13.16** |
| **Total Proved + Probable (3)** | **5,207,833.7** | **3,499,582.6** | **2,538,798.6** | **1,951,566.0** | **1,564,895.2** | **14.00** |

**Notes:**
(1) The unit values are based on net reserve volumes.
(2) Estimates of future net revenue do not represent fair market value.
(3) 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 After Income Taxes Discounted At (%/Year)*
*As of Dec 31, 2022 – Forecast Prices and Costs[(1)]*

| Reserves Category | @0.0% M$ (1,2) | @5.00% M$ (1,2) | @10.00% M$ (1,2) | @15.00% M$ (1,2) | @20.00% M$ (1,2) |
|---|---|---|---|---|---|
| Proved | | | | | |
| Developed Producing | 871,239.7 | 796,579.8 | 698,561.9 | 621,259.6 | 562,336.2 |
| Developed Non-Producing | 10,545.7 | 8,102.8 | 6,549.0 | 5,507.2 | 4,768.3 |
| Undeveloped | 1,390,390.2 | 897,217.5 | 604,175.1 | 417,620.4 | 291,921.9 |
| **Total Proved (3)** | **2,272,175.6** | **1,701,900.1** | **1,309,285.9** | **1,044,387.2** | **859,026.4** |
| **Total Probable** | **1,893,557.6** | **1,103,059.3** | **722,226.3** | **514,362.4** | **389,374.2** |
| **Total Proved + Probable (3)** | **4,165,733.2** | **2,804,959.4** | **2,031,512.2** | **1,558,749.6** | **1,248,400.6** |

**Notes:**
(1) The unit values are based on net reserve volumes.
(2) Estimates of future net revenue do not represent fair market value.
(3) 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 December 31, 2022 Forecast Prices and Costs*

| Reserves Category | Revenue (1) M$ | Royalties (2) M$ | Operating Costs M$ | Development Costs M$ | ADR Costs (3) M$ | Future Net Revenue Before Income Taxes (4) M$ | Income Taxes M$ | Future Net Revenue After Income Taxes M$ |
|---|---|---|---|---|---|---|---|---|
| Total Proved Reserves (5) | 7,632,020 | 1,041,369 | 2,143,617 | 1,509,882 | 181,788 | 2,755,363 | 483,187 | 2,272,176 |
| Total Proved + Probable Reserves (5) | 13,224,837 | 2,133,538 | 3,541,465 | 2,137,078 | 204,923 | 5,207,834 | 1,042,101 | 4,165,733 |

**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 December 31, 2022 Forecast Prices and Costs*

| Reserves Category | Product Type | Future Net Revenue Before Income Taxes (1,2) (discounted @ 10%) M$ | Unit Value (3) $/Mcf $/bbl |
|---|---|---|---|
| **Total Proved Reserves (4)** | Tight Oil (Including Solution Gas and By-products) | 66,392 | 66.58 |
| | Shale Gas (Including By-products) | 1,515,952 | 4.12 |
| | **Total** | **1,582,344** | |
| **Total Proved + Probable Reserves (4)** | Tight Oil (Including Solution Gas and By-products) | 72,723 | 61.25 |
| | Shale Gas (Including By-products) | 2,466,076 | 3.86 |
| | **Total** | **2,538,799** | |

(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. Unit values are calculated using the 10% discount rate divided by the Major Product Type Net reserves for each group.
(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 are based on forecast prices and costs using the three consultant average forecast prices and costs of McDaniel & Associates Consultants Ltd., GLJ Ltd. and Sproule Associates Limited as of January 1, 2023 ("Jan 2023 Consultant Avg.") price forecast.

*Summary of Pricing and Inflation Rate Assumptions*
*As of January 1, 2023 Forecast Prices and Costs*

| | Crude Oil Price Forecasts | | | | | | | Liquids Price Forecasts | | | | Gas Price Forecasts | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Year | WTI Crude Oil $US/bbl (1) | Brent Crude Oil $US/bbl (2) | Edmonton Light Crude Oil $C/bbl (3) | Alberta Bow River Hardisty Crude Oil $C/bbl (4) | Western Canadian Select Crude Oil $C/bbl (5) | Alberta Heavy Crude Oil $C/bbl (6) | Sask Cromer Medium Crude Oil $C/bbl (7) | Edmonton Ethane $/bbl | Edmonton Propane $/bbl | Edmonton Butanes $/bbl | Edmonton Cond. & Natural Gasolines $/bbl | U.S. Henry Hub Gas Price $US/MMBtu | Alberta AECO Spot Price $C/MMBtu (8) | Inflation % (9) | US/CAN Exchange Rate $US/$CAN (10) |
| 2023 | 80.33 | 84.67 | 103.76 | 77.46 | 76.54 | 68.44 | 99.13 | 13.75 | 39.80 | 53.88 | 106.22 | 4.74 | 4.23 | 0.0 | 0.745 |
| 2024 | 78.50 | 82.69 | 97.74 | 78.65 | 77.75 | 69.36 | 93.32 | 14.33 | 39.14 | 52.67 | 101.35 | 4.50 | 4.40 | 2.3 | 0.765 |
| 2025 | 76.95 | 81.03 | 95.27 | 78.42 | 77.55 | 69.92 | 90.90 | 13.77 | 39.74 | 51.42 | 98.94 | 4.31 | 4.21 | 2.0 | 0.768 |
| 2026 | 77.61 | 81.39 | 95.58 | 80.94 | 80.07 | 72.42 | 91.25 | 13.98 | 39.86 | 51.61 | 100.19 | 4.40 | 4.27 | 2.0 | 0.772 |
| 2027 | 79.16 | 82.65 | 97.07 | 82.78 | 81.89 | 74.29 | 92.67 | 14.20 | 40.47 | 52.39 | 101.74 | 4.49 | 4.34 | 2.0 | 0.775 |
| 2028 | 80.74 | 84.29 | 99.01 | 84.92 | 84.02 | 76.43 | 94.52 | 14.49 | 41.28 | 53.44 | 103.78 | 4.58 | 4.43 | 2.0 | 0.775 |

**Notes:**
(1) West Texas Intermediate at Cushing Oklahoma 40 degrees API, 0.5% sulphur
(2) North Sea Brent Blend 37 degrees API, 1.0% sulphur
(3) Edmonton Light Sweet 40 degrees API, 0.3% sulphur
(4) Bow River at Hardisty, Alberta (Heavy stream)
(5) Western Canadian Select at Hardisty, Alberta
(6) Heavy crude oil 12 degrees API at Hardisty, Alberta (after deduction of blending costs to reach pipeline quality)
(7) Midale Cromer crude oil 29 degrees API, 2.0% sulphur
(8) This forecast also applies to direct sales contracts and the Alberta gas reference price used in the Crown royalty calculations
(9) Inflation rates for forecasting prices and costs.
(10) 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 January 1, 2022 to December 31, 2022, were $84.94 bbl for condensate, $52.60/bbl for other NGL (excluding condensate and pentane extracted from the gas stream), $5.29/mcf for natural gas, $82.46/bbl for light and medium oil and $59.22/bbl for heavy crude oil.

## Reserves Reconciliation

*Reconciliation of Gross Reserves by Product Type*
*Forecast Prices and Costs*

| FACTORS | HEAVY CRUDE OIL | | | TIGHT OIL | | |
|---|---|---|---|---|---|---|
| | Gross Proved Mbbl | Gross Probable Mbbl | Gross Proved Plus Probable Mbbl | Gross Proved Mbbl | Gross Probable Mbbl | Gross Proved Plus Probable Mbbl |
| December 31, 2021 (1) | 128.2 | 204.1 | 332.3 | 1,370.1 | 269.0 | 1,639.1 |
| Extensions & Improved Recovery | - | - | - | - | - | - |
| Technical Revisions | (1.1) | (0.1) | (1.2) | 119.2 | (23.9) | 95.3 |
| Discoveries | - | - | - | - | - | - |
| Acquisitions | - | - | - | - | - | - |
| Dispositions | (125.6) | (204.0) | (329.6) | - | - | - |
| Economic Factors (2) | - | - | - | 22.5 | 9.3 | 31.8 |
| Production* | (1.5) | - | (1.5) | (232.1) | - | (232.1) |
| December 31, 2022 (4) | - | - | - | 1,279.7 | 254.4 | 1,534.1 |

| FACTORS | SHALE GAS | | | NATURAL GAS LIQUIDS (3) | | | TOTAL | | |
|---|---|---|---|---|---|---|---|---|---|
| | Gross Proved MMcf | Gross Probable MMcf | Gross Proved Plus Probable MMcf | Gross Proved Mbbl | Gross Probable Mbbl | Gross Proved Plus Probable Mbbl | Gross Proved Mboe | Gross Probable Mboe | Gross Proved Plus Probable Mboe |
| December 31, 2021 (1) | 314,772.8 | 244,603.9 | 559,376.7 | 52,206.5 | 32,798.9 | 85,005.4 | 106,166.9 | 74,039.3 | 180,206.3 |
| Extensions & Improved Recovery | 63,280.6 | 42,451.2 | 105,731.8 | 7,494.5 | 4,756.4 | 12,250.9 | 18,041.3 | 11,831.6 | 29,872.9 |
| Technical Revisions | 29,713.1 | 6,680.1 | 36,393.2 | (5,382.4) | (4,189.3) | (9,571.7) | (312.1) | (3,099.9) | (3,412.0) |
| Discoveries | - | - | - | - | - | - | - | - | - |
| Acquisitions | 23,243.7 | 17,564.9 | 40,808.6 | 3,059.9 | 2,713.9 | 5,773.8 | 6,933.9 | 5,641.4 | 12,575.2 |
| Dispositions | - | - | - | - | - | - | (125.6) | (204.0) | (329.6) |
| Economic Factors (2) | 4,708.0 | 2,525.6 | 7,233.6 | 527.6 | 285.2 | 812.8 | 1,334.8 | 715.4 | 2,050.2 |
| Production* | (21,054.6) | - | (21,054.6) | (2,752.6) | - | (2,752.6) | (6,495.3) | - | (6,495.3) |
| December 31, 2022 (4) | 414,663.6 | 313,825.7 | 728,489.3 | 55,153.5 | 36,365.1 | 91,518.6 | 125,543.8 | 88,923.8 | 214,467.6 |

**Notes:**

(1) Dec 31, 2021 balances reflect the Company's reserves at December 31, 2021 including after giving effect to the acquisition of Distinction Energy Corp. and the Simonette Acquisition

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

(3) 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 32% and pentanes plus represents 3% on a volume basis for Total Proved reserves, and 31% condensate and 3% pentanes plus on a volume basis for Total Proved Plus Probable reserves, as at December 31, 2022.

(4) December 31, 2022 balances reflect the acquisition of incremental working interest in Placid (as shown in the "Acquisitions" category) plus additional technical revisions related to lower forecasts of liquid yields based on recent plant tests as marketing conditions change

## *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 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, 2022, undeveloped reserves represented approximately 67% of total proved reserves and approximately 77% 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.

Based on current conditions, and the 2022 Reserves Report, Kiwetinohk anticipates a well development schedule in which approximately 70% of the future drilling would occur between 2023 to 2027 to develop proven reserves while probable reserves would developed during the 2028-2031 timeframe.

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, 2022 to December 31, 2022, January 1, 2021 to December 31, 2021 and January 1, 2020 to December 31, 2020, based on forecast prices and costs.

**Proved Undeveloped Reserves**

| Year | Heavy Oil (Mbbls) | | Light and Medium Oil (Mbbls) | | Conventional Gas (MMcf) | | Shale Gas (MMcf) | | Natural Gas Liquids (1) (Mbbls) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End |
| 31-Dec-20 | 132.2 | 132.2 | - | 5,448.9 | - | 14,510.5 | 77,162.1 | 77,162.1 | 7,853.0 | 8,690.0 |
| 31-Dec-21 | - | 113.1 | - | - | - | - | 176,478.5 | 205,830.5 | 34,381.0 | 37,367.4 |
| 31-Dec-22 | - | - | - | - | - | - | 66,092.1 | 283,176.1 | 7,633.5 | 37,535.3 |

**Probable Undeveloped Reserves**

| Year | Heavy Oil (Mbbls) | | Light and Medium Oil (Mbbls) | | Conventional Gas (MMcf) | | Shale Gas (MMcf) | | Natural Gas Liquids (1) (Mbbls) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End |
| 31-Dec-20 | 281.0 | 281.0 | - | 7,424.1 | - | 19,815.2 | 19,488.8 | 19,488.8 | 2,015.2 | 3,146.0 |
| 31-Dec-21 | - | 197.8 | - | - | - | - | 151,167.0 | 219,523.2 | 22,375.9 | 29,362.9 |
| 31-Dec-22 | - | - | - | - | - | - | 54,906.1 | 285,449.6 | 6,750.9 | 32,425.2 |

**Proved Plus Probable Undeveloped Reserves**

| Year | Heavy Oil (Mbbls) | | Light and Medium Oil (Mbbls) | | Conventional Gas (MMcf) | | Shale Gas (MMcf) | | Natural Gas Liquids (1) (Mbbls) | |
|---|---|---|---|---|---|---|---|---|---|---|
| | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End |
| 31-Dec-20 | 413.2 | 413.2 | - | 12,873.0 | - | 34,325.7 | 96,650.9 | 96,650.9 | 9,868.2 | 11,836.0 |
| 31-Dec-21 | - | 310.9 | - | - | - | - | 327,645.5 | 425,353.7 | 56,756.9 | 66,730.3 |
| 31-Dec-22 | - | - | - | - | - | - | 120,998.2 | 568,625.7 | 14,384.4 | 69,960.5 |

**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 approximately 32-31% and 3% of the NGL reflected in the Gross Proved and Gross Proved plus Probable categories, respectively, as at December 31, 2022.

### *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 natural gas prices and costs change. The reserves estimates contained herein are based on production expectations, forecast prices and economic conditions as at December 31, 2022. 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.

**ANNUAL DEVELOPMENT COSTS**

| **Year** | **Total Proved** | **Total Proved plus Probable** |
|---|---|---|
| | ***($mm)*** | ***($mm)*** |
| 2023 | 294.7 | 294.7 |
| 2024 | 285.9 | 285.9 |
| 2025 | 345.1 | 345.1 |
| 2026 | 303.5 | 303.5 |
| 2027 | 244.1 | 244.1 |
| Thereafter | 36.6 | 663.8 |
| **Total (Undiscounted)[(1)]** | 1,509.9 | 2,137.1 |
| **Total (Discounted at 10%)** | 1,200.8 | 1,551.4 |

**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 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 December 31, 2022, 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 |
| 211.0 | 198.6 | 225.0 | 113.3 | 18.0 | 12.0 | 83.0 | 44.7 |

**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 December 31, 2022:

| **Unproved (Acres)** | **Gross** | **Net** |
|---|---|---|
| Alberta | 232,619 | 183,100 |
| British Columbia | 25,153 | 11,171 |
| **Total** | 257,772 | 194,271 |

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 year ending December 31, 2023, approximately 58,500 net acres of the Company will come up for expiry. Kiwetinohk believes that, subject to Crown approval approximately 40% 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 $204.9 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.

### *Costs Incurred*

The following table summarizes the costs incurred by KEC for the 12 months ended December 31, 2022.

| | **12 months ended December 31, 2022** |
|---|---|
| | *($MM)* |
| Property acquisition costs: | |
| Proved properties | 54.8 |
| Unproved properties | - |
| Exploration costs | 0.6 |
| Development costs | 245.2 |
| Other [1] | 10.1 |
| **Total:** | 310.7 |

1 Other balance is comprised of prepayment of property plant and equipment and capitalized G&A related to upstream capital.

### *Exploration and Development Activities*

The following table sets for the gross and net exploratory and development wells brought on production in which KEC participated in the 12 months ended December 31, 2022.

| | **Development** | | **Exploratory** | | **Total** | |
|---|---|---|---|---|---|---|
| | **Gross** | **Net** | **Gross** | **Net** | **Gross** | **Net** |
| Natural Gas | 12 | 12 | - | - | 12 | 12 |
| Oil | - | - | - | - | - | - |
| Service | - | - | - | - | - | - |
| Stratigraphic Test | - | - | - | - | - | - |
| Dry | - | - | - | - | - | - |
| **Total:** | 12 | 12 | - | - | 12 | 12 |

In 2023, Kiwetinohk intends to focus ***capital spending*** on high rate of return oil and gas production and strong production per share growth. The program aims to delineate and prove the assets while retaining land in both Simonette and Placid.

### *Production Estimates*

The following table sets out for each product type the gross volume of production estimated for the twelve-month period ending December 31, 2023 in the estimates contained in the 2022 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 Twelve-Month Period Ending December 31, 2023

| | **Shale Gas** | **NGL** | **Tight Oil** | **Total** |
|---|---|---|---|---|
| **Reserve Category** | ***(mmcf)*** | ***(mbbl)*** | ***(mbbl)*** | ***(mboe)*** |
| Proved | 30,300 | 4,095 | 168 | 9,314 |
| Probable | 2,800 | 401 | 3 | 871 |
| Total Proved plus Probable | 33,100 | 4,497 | 171 | 10,185 |

### *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** | | | |
|---|---|---|---|---|
| | **March 31, 2022** | **June 30, 2022** | **September 30, 2022** | **December 31, 2022** |
| **Average Gross Daily Production**[(1)(5)] | | | | |
| Shale Gas (mmcf/d)[(7)] | 44.0 | 51.2 | 53.9 | 81.9 |
| Natural Gas Liquids (bbl/d) | 1,560.6 | 1,869.7 | 1,943.8 | 2,663.7 |
| Condensate[(2)] | 3,475.4 | 5,673.6 | 4,275.7 | 8,365.3 |
| Tight Oil (bbl/d)[(3)(7)] | 876.1 | 718.2 | 1,281.9 | 66.1 |
| Heavy Crude Oil[(3)] (bbl/d) | 12.8 | 10.0 | - | (8.4) |
| Combined (boe/d) | 13,253.2 | 16,810.1 | 16,486.7 | 24,744.9 |
| **Average Production Prices Received** | | | | |
| Shale Gas ($/mcf)[(7)] | 6.35 | 9.98 | 10.20 | 8.12 |
| Natural Gas Liquids ($/bbl) | 66.03 | 86.71 | 75.49 | 68.82 |
| Condensate ($/bbl) [(2)] | 115.77 | 131.33 | 118.50 | 105.09 |
| Tight Oil (bbl/d)[(3)(7)] | 115.85 | 133.47 | 101.05 | 90.73 |
| Heavy Crude Oil($/bbl) | 85.96 | 107.11 | - | 113.91 |
| Combined ($/boe) | 66.96 | 90.17 | 80.86 | 70.04 |
| **Royalties Paid** [(9)] | | | | |
| Shale Gas ($/mcf)[(7)] | 0.03 | 0.76 | (0.46) | (0.37) |
| Natural Gas Liquids ($/bbl) | (12.05) | (9.61) | (31.13) | 0.41 |
| Condensate ($/bbl) [(2)] | (18.31) | (9.37) | (23.80) | (13.60) |
| Tight Oil (bbl/d)[(3)(7)] | (9.53) | (18.07) | (14.80) | 25.74 |
| Heavy Crude Oil($/bbl) | (1.79) | 8.63 | - | (0.18) |
| Combined ($/boe) | (6.74) | (2.69) | (12.51) | (5.72) |
| **Production Costs**[(3)] | | | | |
| Shale Gas ($/mcf)[(7)] | (1.59) | (2.02) | (1.85) | (1.20) |
| Natural Gas Liquids ($/bbl) | (9.56) | (12.11) | (11.12) | (7.20) |
| Condensate ($/bbl) [(2)] | (9.56) | (12.11) | (11.12) | (7.20) |
| Tight Oil (bbl/d)[(3)(7)] | (9.56) | (12.11) | (11.12) | (7.20) |
| Heavy Crude Oil($/bbl) | (9.56) | (12.11) | - | (7.20) |
| Combined ($/boe) | (9.56) | (12.11) | (11.12) | (7.20) |
| **Transportation Costs** | | | | |
| Shale Gas ($/mcf)[(7)] | (0.68) | (0.92) | (1.27) | (1.00) |
| Natural Gas Liquids ($/bbl) [(8)] | (5.12) | (3.81) | (5.45) | (4.40) |
| Condensate ($/bbl) [(2) (8)] | (5.12) | (3.81) | (5.45) | (4.40) |

| | Quarter Ended | | | |
|---|---|---|---|---|
| | March 31, 2022 | June 30, 2022 | September 30, 2022 | December 31, 2022 |
| Tight Oil (bbl/d)(8)(7) | (5.12) | (3.81) | (5.45) | (4.40) |
| Heavy Crude Oil($/bbl) (8) | (5.12) | (3.81) | (5.45) | (4.40) |
| Combined ($/boe) | (5.12) | (4.67) | (6.63) | (5.27) |
| **Netback Received**(4)(6) | | | | |
| Shale Gas ($/mcf) (7) | 4.12 | 7.80 | 6.62 | 5.55 |
| Natural Gas Liquids ($/bbl) | 39.30 | 61.19 | 27.79 | 57.63 |
| Condensate(2) | 82.78 | 106.05 | 78.12 | 79.88 |
| Tight Oil (bbl/d)(7) | 91.64 | 99.48 | 69.68 | 104.87 |
| Heavy Crude Oil ($/bbl) | 69.49 | 99.82 | - | 102.12 |
| Combined ($/boe) | 46.11 | 70.69 | 50.59 | 51.85 |

**Notes:**

(1) Working interest before the deduction of royalties.

(2) Comprised of the condensate that is extracted in the field and plant condensate.

(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) The Company closed the acquisition of the incremental working interest in assets held. Production data includes consolidated data effective as of September 15, 2022.

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

(7) At December 31, 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.

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

(9) GCA credits received by the Company have been allocated on a pro rata share.

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, 2022.

| | Shale Gas | NGL | Condensate | Tight Oil | Heavy Crude Oil | Total |
|---|---|---|---|---|---|---|
| | *(mmcf/d)* | *(bbl/d)* | *(bbl/d)* | *(bbl/d)* | *(bbl/d)* | *(boe/d)* |
| Fox Creek Region(1) | 56.6 | 1,931.7 | 5,422.8 | 529.9 | - | 17,324.2 |
| Placid | 22.3 | 850.6 | 1,807.1 | 7.9 | - | 6,380.4 |
| Simonette (3) | 34.4 | 1,081.1 | 3,615.7 | 522.0 | - | 10,943.8 |
| Other Misc. | 1.2 | 80.5 | 34.9 | 205.0 | 3.5 | 527.4 |
| TOTAL(1) (2) | 57.9 | 2,012.3 | 5,457.7 | 734.8 | 3.5 | 17,851.6 |

**Note:**

(1) Numbers may not add due to rounding.

(2) Production data from acquisitions includes data from the April 28, 2021 closing date on the Simonette Acquisition and April 28, 2021 upon obtaining control of Distinction.

(3) Includes West Simonette

## 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 AND DEBT STRUCTURE

### Share Capital

The authorized share capital of the Company as of the date hereof consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares issuable in series. As of December 31, 2022, there were 44,176,710 Common Shares and no Preferred Shares issued and outstanding.

Kiwetinohk adopted a normal course issuer bid (NCIB) which commenced on December 22, 2022 and will expire on December 21, 2023. Kiwetinohk may purchase up to 2,209,159 common shares under the NCIB, representing 5% of the 44,183,181 issued and outstanding common shares as of December 19, 2022. The actual number of common shares that will be purchased under the terms of the NCIB, and the timing of any such purchases, will be subject to market conditions and Kiwetinohk's capital allocation decisions. Use of the NCIB will be made through the facilities of the TSX and/or alternative Canadian trading systems at the market price at the time of purchase. Any common shares purchased under the terms of the NCIB will be cancelled upon their purchase by Kiwetinohk.

#### *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 (a **"Distribution"),** holders of Common Shares shall share equally, share for share, in the property of the Company.

### *Preferred Shares*

As of the date of this AIF, the Company has not issued any Preferred Shares. Preferred Shares may at any time and from time to time be issued in one or more series, each series to consist of such number of shares as may, before the issuance thereof, be determined by the Board.

Subject to the filing of articles of amendment in accordance with the CBCA, the Board may from time to time fix, before issuance, the designation, rights, privileges, restrictions and conditions attaching to each series of Preferred Shares including, without limiting the generality of the foregoing, the amount, if any, specified as being payable preferentially to such series on a Distribution; the extent, if any, of further participation on a Distribution; voting rights, if any; and dividend rights (including whether such dividends be preferential, or cumulative or non-cumulative), if any.

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

> **Voting Rights:** The Board may from time to time fix, before issuance, the voting rights, if any.
>
> **Dividends:** Subject to the preferences accorded to holders of any other shares of the Corporation ranking senior to the Preferred Shares from time to time with respect to the payment of dividends, the holders of each series of Preferred Shares shall be entitled, in priority to holders of Common Shares and any other shares of the Corporation ranking junior to the Preferred Shares from time to time with respect to the payment of dividends, to be paid rateably with holders of each other series of Preferred Shares, the amount of accumulated dividends, if any, specified as being payable preferentially to the holders of such series.
>
> **Distribution:** In the event of a Distribution, holders of each series of Preferred Shares shall be entitled, in priority to holders of Common Shares and any other shares of the Corporation ranking junior to the Preferred Shares from time to time with respect to payment on a Distribution, to be paid rateably with holders of each other series of Preferred Shares the amount, if any, specified as being payable preferentially to the holders of such series on a Distribution.

### Credit Facility

The Company has a Credit Facility of $375.0 million which is comprised of an operating facility of $65.0 million and a syndicated facility of $310.0 million. The Credit Facility is a 364-day committed facility available on a revolving basis until May 31, 2023, at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the Credit Facility will be cancelled and the amount outstanding would be required to be repaid at the end of the non-revolving term, being May 31, 2024. The borrowing base is determined based on the lenders' evaluation of the Company's petroleum and natural gas reserves at the time and commodity prices. The Credit Facility is secured by a $1.0 billion demand floating charge debenture and a general security agreement over all assets of the Company.

The Company plans to continue using the Credit Facility for working capital purposes to fund go forward capital plans in advance of cash flow from new investments and target a net debt to annualized last-twelve-months of adjusted funds flow from operations ratio of no more than 1.0 times.

### Other securities

The Company has 2,716,786 options ($10.36 weighted average exercise price and 4.4 years average life remaining) and 7,555,258 performance warrants ($20,00 weighted average exercise price and 3.6 years average life remaining) outstanding at December 31, 2022.

The Company has cash-settled securities outstanding related to directors share units ("**DSUs**"), restricted share units ("**RSUs**"), and performance share units ("**PSUs**"). Cash settled securities are carried at fair value and vest and are settled over three years based on the trading price of the equivalent number of shares of the Company as at the time of vesting with the exception of DSUs that vest immediately and are settled upon retirement of the director. As at December 31, 2022 the Company had 47,422 DSUs outstanding, 142,494 PSUs outstanding and 184,195 RSUs outstanding.

Additional details are included in the December 31, 2022 annual consolidated financial statements and also in the Compensation Discussion and Analysis section of the Company's Management Information Circular dated May 11, 2022 under the headings "*Equity Compensation Plan Information*" and "*Director Compensation – Approach to Director Compensation*", each of which are available under the Company's profile on the website maintained by the Canadian Securities Administrators at www.sedar.com.

## MARKET FOR SECURITIES

The Company's Common Shares are listed on the TSX under the symbol "KEC." The following table sets forth the reported high and low trading prices and trading volumes of our Common Shares as reported by the TSX for the periods indicated:

| | Common Share Price | | | |
|---|---|---|---|---|
| **2022** | **High** | **Low** | **Close** | **Volume** |
| January (1) | $14.00 | $12.00 | $12.30 | 275,079 |
| February | $12.49 | $11.50 | $11.95 | 522,779 |
| March | $12.90 | $11.80 | $11.95 | 373,475 |
| April | $12.90 | $11.49 | $11.95 | 433,792 |
| May | $13.84 | $11.09 | $13.75 | 863,973 |
| June | $18.92 | $13.86 | $14.04 | 1,286,264 |
| July | $16.59 | $12.33 | $15.92 | 468,875 |
| August | $16.79 | $13.33 | $15.67 | 448,411 |
| September | $16.43 | $13.52 | $14.13 | 228,274 |
| October | $17.35 | $14.00 | $17.35 | 268,214 |
| November | $17.73 | $14.22 | $14.65 | 587,496 |
| December | $15.06 | $13.18 | $14.57 | 359,449 |
| **2023** | | | | |
| January | $14.99 | $13.65 | $14.05 | 355,914 |
| February | $14.49 | $12.38 | $12.72 | 133,700 |
| March 1-7 (2) | $13.12 | $12.67 | $12.88 | 17,100 |

Notes:

(1) During the 2021 calendar year there was no market through which the Common Shares or any other securities of the Company were able to be sold. On January 14, 2022, the Company completed a listing of its outstanding Common Shares on the Toronto Stock Exchange and commenced trading.

(2) Represents the volume weighted average daily Common Share price.

## PRIOR SALES

The following table summarizes for each class of securities of the Corporation that is outstanding but not listed or quoted on a marketplace, the price at which securities of the class have been issued during the financial year ended December 31, 2022 and the number of securities of the class issued at that price and the date on which the securities were issued.

| Date of Issuance | Number and Type of Securities | Issue or Exercise Price per Security ($) |
|---|---|---|
| March 23, 2022 | 88,750 Stock Options | $12.21 |
| March 31, 2022 | 13,749 DSUs | $11.97 |
| May 11, 2022 | 11,000 Stock Options | $12.36 |
| June 30, 2022 | 10,701 DSUs | $15.38 |
| August 10, 2022 | 12,600 Stock Options | $14.33 |
| September 30, 2022 | 11,771 DSUs | $13.98 |
| December 19, 2022 | 171,763 Stock Options | $14.11 |
| December 19, 2022 | 184,195 RSUs | $14.12 |
| December 19, 2022 | 142,494 PSUs | $14.12 |
| December 31, 2022 | 11,201 DSUs | $14.69 |

## ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

As of December 31, 2022 there are no securities in escrow or that are subject to a contractual restriction on transfer.

## 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 (3) | Percentage of Common Shares |
|---|---|---|
| ARC(1) | 27,539,624 | 62.3% |
| Luminus(2) | 5,202,334 | 11.8% |

**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.

(3) This information has been obtained by the Company from filings on the System for Electronic Disclosure by Insiders at www.sedi.ca as of the date of this AIF.

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 two ARC nominees on the Board. As ARC exercises control or direction over 40% or more of the Common Shares, ARC is entitled to three director nominees for election to the Board; however, at the date of this AIF, ARC has two director 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.

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**<br>Calgary, AB<br>Canada | Director (Chair)<br>• *Audit Committee Member*<br>• *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**<br>Calgary, AB<br>Canada | Chief Executive Officer and Director<br>• *Reserves Committee Member*<br>• *Sustainability Committee Member* | Patrick Carlson has been the Chief Executive Officer of Kiwetinohk since February 12, 2018 and was President and Chief Executive Officer of Distinction from April 2021 through September 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)]<br>(2.30%) |
| **Leland Corbett**<br>Calgary, AB<br>Canada | Director<br>• *Compensation Committee Member*<br>• *Sustainability Committee Member*<br>• *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<br>(0.07%) |
| **Kaush Rakhit**<br>Calgary, AB<br>Canada | Director<br>• *Reserves Committee Member*<br>• *Compensation Committee Member* | Kaush Rakhit is a former senior executive at Canadian Discovery Ltd. where he held the role of Chief Executive Officer. He founded Rakhit Petroleum Consulting Ltd. in 1989, which purchased and merged with Canadian Discovery Ltd. ("CDL") in 2005. He is currently the Chairman of the Board of Directors of CDL. | August 2018 | 102,000<br>(0.23%) |
| **Nancy Lever**<br>Calgary, AB<br>Canada | Director<br>• *Reserves Committee Member*<br>• *Sustainability Committee Member*<br>• *Compensation Committee Member* | Nancy Lever is a former Advisor at ARC Financial Corp. She was with ARC Financial Corp. from 1993 through 2022. | September 2021 | --[(1)] |
| **Steve Sinclair**<br>Calgary, AB<br>Canada | Director<br>• *Audit Committee Member (Chair)*<br>• *Compensation Committee Member* | Steve Sinclair is a former senior executive at ARC Resources Ltd. where he held the role of Chief Financial Officer. He was previously a Director and Audit Chair of TransGlobe Energy Corporation and of Deltastream Energy Corp. | September 2021 | 15,000<br>(0.03%) |
| **Beth Reimer-Heck**<br>Calgary, AB<br>Canada | Director<br>• *Audit Committee Member*<br>• *Sustainability Committee Member*<br>• *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 | 5,000<br>(0.01%) |
| **Judith Athaide**<br>Calgary, AB<br>Canada | Director<br>• *Sustainability Committee Member*<br>• *Governance and Nominating Committee Member* | Judith Athaide is a Corporate Director serving on the Boards of Canada Pension Plan Investments Board, Computer Modelling Group Ltd, HSBC Bank Canada and Sustainable Development Technology Canada. She is also the President and CEO of The Cogent Group Inc., a private strategic advisory firm. | February 2022 | 9,020<br>(0.02%) |
| **John Whelen**<br>Calgary, AB<br>Canada | Director<br>• *Audit Committee Member*<br>• *Compensation Committee Member* | John Whelen is a former senior executive at Enbridge Inc. where he held a number of roles, including Executive Vice President and Chief Development Officer, Executive Vice President and Chief Financial Officer, Senior Vice President and Controller and Senior Vice President of Corporate Development. | February 2022 | 40,000<br>(0.09%)-- |
| **Jakub Brogowski**<br>Calgary, AB<br>Canada | Chief Financial Officer | Jakub Brogowski has been the Chief Financial Officer of Kiwetinohk since December 2018 and was the Chief Financial Officer of Distinction from April 2021 through September 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)]<br>(0.03%) |
| **Mike Backus**<br>Calgary, AB<br>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 | N/A | 25,000<br>(0.06%) |

| Name, Province and Country of Residence | Position Held | Principal Occupation for the Last Five Years | Director Since | Number and Percentage of Common Shares Held |
|---|---|---|---|---|
| | | predecessor, Nexen Inc. | | |
| **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 | 10,000 (0.02%) |
| **John Maniawski** Calgary, AB Canada | President, Green Energy Division | John Maniawski was appointed President, Green Energy Division in November, 2021. John has 32 years of experience in the power, utility and pipeline sectors. At Evolugen, he led the development, energy marketing and regulatory overview of a renewable energy business. At Enbridge, he led and supported the development and acquisition of a $4 billion and 2,000 MW renewable platform in North America. | N/A | 5,000 (0.01%) |
| **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 License 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%) |
| **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(6) (0.10%) |
| **Lisa Wong** Calgary, AB Canada | Senior Vice President, Business Systems | Lisa Wong has been the Senior 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%) |
| **Chris Lina** Calgary, AB Canada | Vice President, Projects | Chris Lina has been the Vice President, Projects since January, 2022 and brings over 27 years of experience in project leadership and execution to Kiwetinohk. Prior to this role, Chris led billion dollar projects in petrochemicals, oil and gas including hydrogen and ammonia. | | -- |

**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 27,539,624 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 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) 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, 2022, the current directors and officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, 1,556,630 Common Shares, representing approximately 3.5% of the then 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.

### *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

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.

## 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, John Whelen, Kevin Brown and Beth Reimer-Heck. Each of the members of the Audit Committee is considered "financially literate" and Mr. Sinclair, Mr. John Whelen, 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.

| | **2021** | **2022** |
|---|---|---|
| | *($)* | *($)* |
| Audit Fees[(1)] | 237,000 | 305,000 |
| Audit-Related Fees[(2)] | 75,000 | 60,000 |
| Tax Fees[(3)] | 6,000 | 95,000 |
| All Other Fees[(4)] | 56,010 | 165,000 |
| **Total** | **374,010** | **625,000** |

**Notes:**

(1) Represents 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 aggregate fees billed for tax compliance, tax advice and tax planning.
(4) Represents aggregate fees billed for due diligence related to acquisitions, base shelf prospectus, joint information circular and other.

## 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

McDaniel is 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, McDaniel owns beneficially, directly or indirectly, less than 1% of the outstanding Common Shares of Kiwetinohk or any associate or affiliate thereof.

Our auditors, Deloitte LLP are 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 audited consolidated financial statements and Management's Discussion and Analysis of the Company for the years ended December 31, 2022 and 2021, are available under the Company's profile on the website maintained by the Canadian Securities Administrators 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 Reserves Report**" means the independent reserves report prepared by McDaniel dated March 23, 2022 evaluating the reserves attributable to certain of the assets of Kiwetinohk and its subsidiaries as at December 31, 2021.

"**AACE**" means American Association of Cost Engineering.

"**AAPL**" American Association of Professional Landmen.

"**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 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 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 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*".

"**Annual Information Form**" or "**AIF**" has the meaning ascribed thereto under the heading "*Presentation of Information and Exchange Rate Information*".

"**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*".

"**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, variants or derivations of it.

"**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, as amended.

"**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 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.

"**DRIPA**" means the *Declaration on the Rights of Indigenous Peoples Act*, SBC 2019, c 44, as amended.

“**DSU**” means a deferred share unit granted under the Share Unit Plan.

"**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*".

"**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.

"**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**" means the wells drilled and completed in the Gilby Area in Central Alberta as part of a farm in an option agreement with Journey Energy Inc..

"**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.

"**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.

"**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*".

"**NI 45-106**" means National Instrument 45-106 - *Prospectus Exemptions of the Canadian Securities Administrators*;

"**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.

"**OPEC**" means the Organization of the Petroleum Exporting Countries.

"**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.

"**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*".

"**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.

"**Preferred Shares**" means the preferred shares in the capital of Kiwetinohk as constituted on the date hereof.

“**PSU**” means a performance share unit granted under the Share Unit Plan.

"**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.

“**RSU**” means a restricted share unit granted under the Share Unit Plan.

"**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*".

"**Shareholders**" means the holders of Common Shares from time to time.

“**Share Unit Plan” means the share unit plan of the Company.**

"**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.

"**UNDRIP Act**" means the United Nations Declaration on the Rights of Indigenous Peoples Act.

"**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 defense 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**" or "**heavy 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"

**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 judgmental 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 "C"

**Form 51-101F2 – Report on Reserves Data by**
**<u>Independent Qualified Reserves Evaluator or Auditor</u>**

Please see attached.

March 7, 2023

**Kiwetinohk Energy Corp.**
1700, 250 – 2nd Street SW
Calgary, Alberta
T2P 0C1

Attention: The Board of Directors of Kiwetinohk Energy Corp.

Re: **Form 51-101F2**
**Report on Reserves Data by Independent Qualified Reserves Evaluator or Auditor of Kiwetinohk Energy Corp. (the "Company")**

To the Board of Directors of Kiwetinohk Energy Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2022. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2022 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 + 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, 2022, and identifies the respective portions thereof that we have evaluated and reported on to the Company's Board of Directors:

| Independent Qualified Reserves Evaluator | Effective Date of Evaluation Report | Location of Reserves | Net Present Value of Future Net Revenue $M (before income taxes, 10% discount rate) | | | |
|---|---|---|---|---|---|---|
| | | | Audited | Evaluated | Reviewed | Total |
| McDaniel | December 31, 2022 | Canada | - | 2,538,798.6 | - | 2,538,798.6 |

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

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

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

Executed as to our report referred to above:

**MCDANIEL & ASSOCIATES CONSULTANTS LTD.**

Brian R. Hamm, P.Eng.
President & CEO

Calgary, Alberta, Canada
March 7, 2023

## APPENDIX "D"

### 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 December 31, 2022.

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

March 7, 2023