Annual Information Form

For the year ended December 31, 2024

March 4, 2025

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APPENDICIES

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 power business unit is advancing pre-construction development plans for an Alberta-based power generation project portfolio that currently includes solar, natural gas-fired power and carbon capture and storage ("CCS") facilities. The Company has no history of operating such business. None of the Company's power projects have reached a final investment decision while under the control of Kiwetinohk. The Company's 101 MW Opal gas-fired power project achieved full regulatory approval reaching AESO stage 5 in February 2024. Subsequent to receiving full regulatory approval, the Opal project was sold (See "*Power Development Projects"* for further information). The Company's 400 MW Homestead solar project received full regulatory approval on February 28, 2025, which triggers the payment of its Generating Unit Owner's Contribution ("GUOC") in March 2025. The remaining projects in the portfolio are at earlier development stages and have not obtained full regulatory approval and require further funding to reach this milestone. Furthermore, none of the Company's CCS projects have a final design, performance projection or cost estimate, nor have they obtained full regulatory approval or internal or external funding. Successful execution of the Company's power business unit project portfolio requires access to additional capital, strategic partners, offtake contracts and other resources, development or improvement of technology in certain cases and a favourable regulatory regime, among others, which may be outside of the Company's control. While the Company believes its strategy for building a power business unit has a 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, 2024.

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		
	2024	**2023**	**2022**
High for the period	$0.7510	$0.7617	$0.8031
Low for the period	$0.6937	$0.7207	$0.7217
End of the period	$0.6950	$0.7561	$0.7383
Average for the period(1)	$0.7302	$0.7410	$0.7692

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 4, 2025, based on the published rate of the Bank of Canada, was $1.00 = US$0.6902.

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", "seek", "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 the Company's plans for the development of its upstream assets;
- the importance of traditional fuels such as natural gas during the energy transition;
- 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 and generate improved profitability from such projects;
- the Company's ability to successfully develop its power business unit, including the future development of power projects and the production of reliable, dispatchable affordable energy with lower GHG emissions intensity relative to electricity generated in Alberta currently;
- the Company's ability to procure financing for the development of future projects within its power business unit;
- expectations relating to the outcome of the Alberta Energy and Minerals review of the Company's Evaluation Agreement with respect to its carbon hubs;
- future commodity prices and other market prices and costs;
- the nature, timing and development of the Company's capital projects;

- 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 portfolios, including its ability to raise capital;
- expectations regarding contractual obligations and commitments, benefits therefrom and their expected timing of funding;
- the Company's expected use of the Credit Facility for working capital purposes to fund go forward capital plans;
- expectations regarding the timing of any extension or renewal of the PSG from EDC;
- 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;
- future costs, including abandonment and reclamation cost expectations and Asset Retirement Obligations;
- access to third-party infrastructure and the expected limitations, costs and benefits thereof;
- expectations relating to existing and proposed transportation and processing infrastructure and the contracts relating thereto and the expected benefits thereof, including expectations that the expanded Trans Mountain Pipeline and Costal GasLink Pipeline will reduce the discount in commodity pricing by providing Canadian producers better access to international markets; ;
- the use of risk-management techniques, including hedging;
- the Company's estimates of future interest and foreign exchange rates;
- expectations regarding the implementation of tariffs in North America and globally, which may include tariffs on Canadian goods such as oil and gas, and other imports and exports which impact the energy markets;
- 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;
- industry conditions pertaining to the industries in which the Company operates;
- 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 outcome of certain key lawsuits pertaining to the issue of industrial development within First Nations territories or pertaining to their treaty rights, including claims filed by the Beaver Lake Cree Nation, Duncan's First Nation, Athabasca Chipewyan First Nation and Siksika Nation;
- the Company's management team as it evolves, including the continuity of employment of any person;
- 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 obtain financing necessary for the advancement of the Company's business plan on acceptable terms;
- 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, 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, and other financial instruments as they emerge and evolve from time to time related to the production of electricity successfully to customers;
- the Company's future production levels;
- the applicability of technologies for recovery and production of the Company's reserves;
- the recoverability of the Company's reserves;
- the performance of wells;
- 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, 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;
- near and long-term impacts of tariffs or other changes in trade policies in North America, as well as globally;
- inflation rates, commodity and labour prices;
- interest rates and foreign exchange rates;
- the ability to maintain government leases; and
- the ability to obtain or maintain insurance coverage.

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:

- variability of natural gas, oil and other hydrocarbon prices;
- the ability of the Company to achieve its investment and development objectives;
- risks associated with exploration, development and production of crude oil and natural gas, and drilling for unconventional oil, NGL and natural gas;
- currency, exchange and interest rates;
- the risks and limitations of forecasting reserves data;
- global economic, financial and political conditions, including the results of ongoing trade negotiations in North America, as well as globally;
- 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;
- risks associated with advancement of development plans for the power generation portfolio
- greenhouse gas emissions regulations, carbon taxes and environmental compliance costs;
- regulatory and voluntary emissions offset regulations and markets;

- pandemics and epidemics;
- market constraints and access to services and equipment;
- talent, recruitment and retention of key personnel;
- technology risks, including cybersecurity incidents;
- risks associated with seasonality, and seasonal weather patterns;
- 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. Actual results may differ significantly from the estimates presented herein. 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 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.

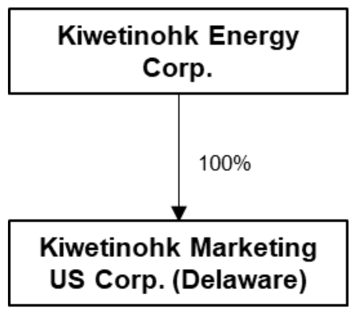
CORPORATE STRUCTURE

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.

Kiwetinohk and Distinction entered into a Business Combination Agreement on or about September 22, 2021 (the "Business Combination"). 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 – 2nd Street SW, Calgary, Alberta, T2P 0C1 and the registered office of the Company is located at 3700 Devon Tower, 400 - 3rd Avenue S.W., Calgary, Alberta, T2P 4H2.

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



The Company currently holds 100% of various limited partnerships intended to segregate and facilitate the development of certain projects within its power development portfolio. The limited partnerships are not material to the overall business of Kiwetinohk in aggregate or individually.

GENERAL HISTORICAL DEVELOPMENT OF THE BUSINESS

Three Year History

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 for the issuance of up to $500 million in aggregate for a period of 25 months.
- 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, 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 resource for cash consideration of $59.2 million.
- October 4 - the Alberta government awarded Kiwetinohk the right to advance planning on two CCS hubs.

2023

- Feb 23 - Kiwetinohk brought on stream three Duvernay wells at its 4-34 pad.
- March 22 - Kiwetinohk announced the departure of John Maniawski, former president of the Power Division.
- May 1 - Kiwetinohk brought on stream two Montney wells in Placid West.

- May 3 - Nancy Lever retired from the board of directors of Kiwetinohk and Colin Bergman was appointed as a new director.
- June 1 - Kiwetinohk brought on stream two Montney wells in Placid West.
- June 5 - Kiwetinohk amended and increased the unsecured demand revolving letter of credit facility with Export Development Canada from $15.0 million to $75.0 million.
- August 3 - Kiwetinohk disposed of non-core assets in the West Simonette area for $2.5 million.
- August 24 - Kiwetinohk appointed Fareen Sunderji as President of the Power Division.
- September 13 - Kiwetinohk brought on stream two Duvernay wells in Tony Creek.
- October 1 – Kiwetinohk completed construction of an expansion to the Company's 10-29 processing plant in Simonette which increased inlet capacity by ~30 MMcf/d through addition of two new compressors.
- November 1 - Kiwetinohk disposed of non-core assets in the Rimbey area for estimated proceeds of $17.6 million subsequent to closing adjustments.
- Nov 19 - Kiwetinohk brought on stream four Duvernay wells at the 14-29 pad which combined to produce approximately 11,900 boe/d on average in December 2023.
- December 13 - Kiwetinohk announced that its Board of Directors had approved a 2024 budget that included upstream capital expenditures of $270 - $295 million with a three year target to achieve annual targeted upstream production of 40,000 boe/d by 2026.

2024

- Feb 21 - Kiwetinohk brought on stream three Duvernay wells at the 8-23 pad in Simonette.
- May 24 - Kiwetinohk filed a renewal short-form base shelf prospectus to provide financing flexibility and additional options for quicker access to public equity and/or debt markets for the issuance of securities up to $500 million in aggregate over a period of 25 months, if and when desirable.
- May 27 - Kiwetinohk published a Letter to Shareholders from the CEO outlining core elements of Kiwetinohk's strategy.
- May 27 - Kiwetinohk's bank lenders agreed to renew and increase Kiwetinohk's Credit Facility from $375 million to $400 million, comprised of an operating facility of $65.0 million and a syndicated facility of $335.0 million. Concurrently with the increase in Credit Facility, Kiwetinohk amended and increased the unsecured demand revolving letter of credit facility with Export Development Canada from $75.0 million to $125.0 million.
- July 11 - Kiwetinohk brought on stream three Duvernay wells at the 11-24 pad in Tony Creek
- July 31 - Kiwetinohk recognized a $29.2 million accounting impairment representing the book value for the Opal and Little Flipi gas-fired peaking projects, the Granum and Phoenix solar projects and the Black Bear and Flipi natural gas combined-cycle projects.
- August 2 - Kiwetinohk brought on stream three Duvernay wells at the 10-29 pad in Tony Creek
- September 1 - Kiwetinohk brought on stream one Duvernay well and one Montney well at the 1-28 pad in Simonette. This represents the first Simonette Montney well drilled by the Company in the underdeveloped Montney acreage.
- November 1 - Kiwetinohk extended its commitment on the Alliance Pipeline to October 31, 2032 with options for extensions thereafter. Tolls on the US segment of the pipeline were fixed for a minimum of seven years; while the Company elected to renew tolls on the Canadian segment on an evergreen annual basis, starting on November 1, 2025, pending an anticipated toll methodology review of the Canadian segment by the Canadian Energy Regulator.
- November 18 - Kiwetinohk brought on stream two Duvernay and one Montney well at the 8-23 pad in Simonette.
- December 16 - Kiwetinohk announced that its Board of Directors had approved a 2025 budget that included upstream capital expenditures of $290 - $315 million and expected annual production of 31.0 - 34.0 Mboe/d in 2025.
- December 27 - Kiwetinohk brought on stream two Duvernay wells at the 9-11 pad in Simonette. The third well drilled on this pad was brought on stream in January 2025.

Recent Developments

- January 22 - Alicia Kilmer was appointed as a new director.
- February 4 - Kiwetinohk disposed of its proposed 101-MW Opal natural gas fired power project, including all Opal assets, material contracts, leases and permits, for proceeds of $21 million.
- February 20 - Kiwetinohk brought on stream two Duvernay and one Montney well at the 14-29 pad in Simonette.
- February 28 - Kiwetinohk's Homestead solar project receives full permits and licences from the Alberta regulator and advances into Stage 5 of the AESO review process.

Significant Acquisitions

No significant acquisitions were completed in 2024.

DESCRIPTION OF KIWETINOHK'S BUSINESS

Kiwetinohk produces natural gas, natural gas liquids, oil and condensate and is advancing pre-construction development plans for an Alberta-based power generation project portfolio that currently includes solar, natural gas-fired power and carbon capture and storage (CCS) facilities. The successful development of Kiwetinohk's power portfolio would support the future production of reliable, dispatchable, and affordable energy with lower emissions intensity relative to energy generated through Alberta's grid today.

The Company's capital investment program is solely focused on the maintenance and growth of its upstream assets and it seeking project sales or third-party funding for its power projects.

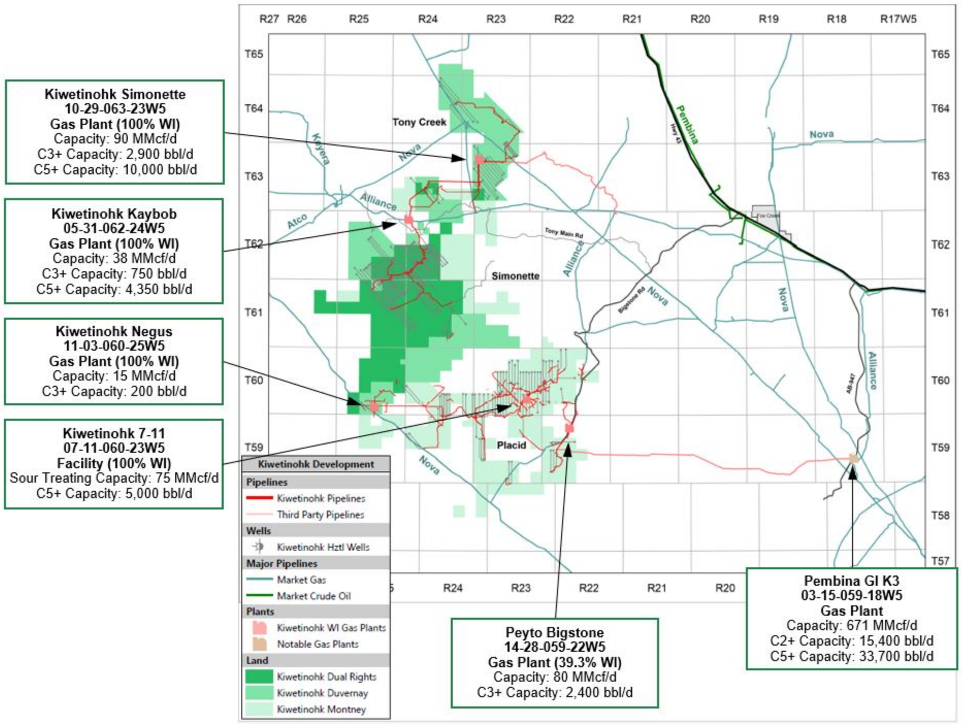
Upstream Business

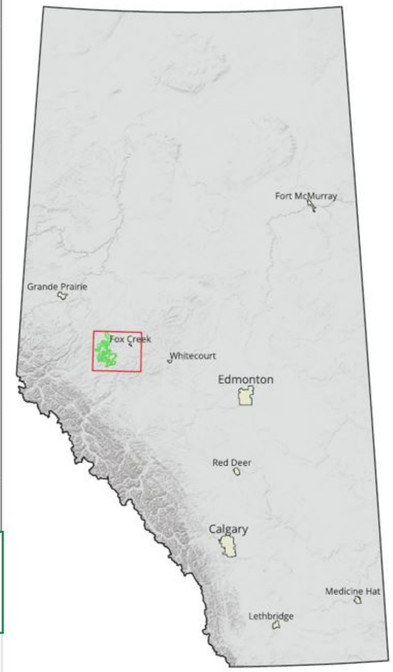
The upstream business unit is involved in the development and production of petroleum and natural gas reserves in western Canada, with a focus on profitable early to mid-life liquids-rich natural gas properties that are expected to offer competitive economic resource potential and compelling returns. Upstream assets consist of high operating netback, liquids-rich natural gas production in the Duvernay and Montney resources, primarily within the Fox Creek region, with owned infrastructure for processing the majority of the Company's production and egress pipeline capacity contracted for transportation of natural gas production to points in Alberta and Chicago, Illinois, United States.

Fox Creek

The Company's most important upstream assets lie within the Simonette and Placid areas of the Fox Creek region (approximately 140 km southeast of Grand Prairie, Alberta) shown on the map below.

The Fox Creek assets are primarily focused on the development of the liquids-rich Duvernay and Montney 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 for the following reasons:

- Proven development opportunities in the liquids-rich Montney and Duvernay formations
- Significant existing owned and operated 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 contributes to higher and more stable operating netbacks from production
- Access to multiple egress options with secured pipeline transportation contracts
- Potential consolidation opportunities in the region

Development in the Simonette area is primarily focused on the liquids-rich Duvernay formation with some production from the overlying Montney formation on the same land base which the Company continues to delineate through its development program. Production from the Simonette asset averaged 20,966 boe/d in 2024 (47% liquids) comprised of 3,137 boe/d NGL, 6,750 boe/d in oil and condensate, and 66.5 mmcf/d shale gas.

In the Placid area, just south of Simonette, the liquids-rich Montney formation is the primary focus of development. Production from the asset averaged 5,892 boe/d in 2024 (41% liquids) comprised of 797 boe/d NGL, 1,643 boe/d oil and condensate and 20.7 mmcf/d shale gas.

The Company believes its Duvernay and Montney properties in Fox Creek are suited to its upstream expertise in multi-stage fractured horizontal wells. Several members of the Kiwetinohk upstream team possess relevant expertise acquired from past experience at other companies operating in similar formations and through experience gained in developing the Company's assets since Kiwetinohk went public in early 2022. 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 lateral length, well spacing, fracture spacing and fracture size, 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. In their evaluation in 2024, McDaniel assigns proved plus probable reserves within the Reserves Report to 115 Duvernay and 31 Montney horizontal drilling locations at Simonette, and 28 Montney horizontal locations at Placid.

The Company continues to optimize value 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 gas plants, frac spreads and drilling rig components
- Artificial lift system selection and adaptation and operation optimization

In Simonette, the Company has a 100% working interest in extensive, well-designed and well-maintained surface facilities. There is an extensive gas gathering system converging on the Company's two gas plants with a combined inlet gas capacity of 128.0 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 Company-owned water source wells and to a competitor-owned intake on the Little Smoky River. The gas plants current connections to transportation and market hubs are described in the Midstream, Marketing and Transportation Arrangements section.

In addition, the Company has a 100% working interest in two Placid facilities with a combined processing capacity of 90.0 mmcf/d and condensate capacity of 5,000 bbl/d. It also has a 39.3% working interest in the Bigstone Gas Plant, operated by Peyto Exploration & Development Corp., which has a total processing capacity of 80.0 mmcf/d and natural gas liquids capacity of 2,400 bbl/d.

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 principal attributes of the Company's major oil and gas properties are summarized in the table below. 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 total proved plus probable reserves, all as assigned in the 2024 Reserves Report.

	Gross Production (Fourth quarter 2024 daily average)				Gross Reserves - Proved Develop 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	12,493.2	262.2	89.3	27,641.2	18.7	0.7	147.9	783.9
Other Misc.	2.3	2.1	0.1	16.0	0.0	0.0	0.0	0.0
Total [2]	**12,495.5**	**264.3**	**89.4**	**27,657.2**	**18.7**	**0.7**	**147.9**	**783.9**

Property	Gross Reserves - Total Proved [3] NGL [4] mmbbl	Tight Oil mmbbl	Shale Gas bcf	NPV10 [5] $mm	Gross Reserves - Total Proved plus Probable [3] NGL [4] mmbbl	Tight Oil mmbbl	Shale Gas bcf	NPV10 [5] $mm
Fox Creek Region	0.0	0.7	416.3	1,667.5	113.1	0.8	794.6	2,860.7
Other Misc.	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
Total [2]	**60.7**	**0.7**	**416.3**	**1,667.5**	**113.1**	**0.8**	**794.6**	**2,860.7**

Notes:
(1) Includes tight oil and heavy crude oil in accordance with the standards contained in COGEH and the reserves definitions contained in NI 51-101 and CSA 51-324.
(2) Numbers may not add due to rounding.
(3) All reserves estimates are from the 2024 Reserves Report.
(4) For NI 51-101 purposes, condensate production is included with NGL production.
(5) NPV10 figures have been calculated on a before taxes basis. NPV10 is a supplementary financial measure which does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See "Non-GAAP and Other Financial Measures" section of this AIF.

Property	Landholdings [1] Undeveloped Net Acres	Developed Net Acres
Fox Creek Region		
Duvernay	63,442	57,192
Montney	95,490	48,464
Other formations	24,480	23,338
Other Areas	4,557	8,255
Total [4]	**187,969**	**137,249**

Notes:
(1) Landholdings shown above are acres in the Montney and Duvernay formations, among others, net of the ownership interest of third parties. Acreage position is expressed as at December 31, 2024. 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 (e.g. Duvernay and Montney lands do overlap in the Simonette block), the acreage has been counted twice.
(2) Numbers may not add due to rounding.

Property	Asset Retirement Obligations [1][2][3] Inactive Undiscounted $mm	Active Undiscounted $mm	Future Undiscounted $mm	Total Undiscounted $mm
Fox Creek Region	$34.4	$79.3	$30.5	$144.2
Other Misc.	$0.0	$0.3	$0.0	$0.3
Total [4]	**$34.4**	**$79.6**	**$30.5**	**$144.5**

(1) "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. Balances presented were attributed to the Company within McDaniel 2024 Reserve report see "Disclosure of Reserves Data".
(2) 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 uninflated, undiscounted, 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 70% of Kiwetinohk's decommissioning liabilities on its financial statements are associated with active properties that have production and attributable reserves. There is approximately $34.4 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.
(3) The Company's current inactive and active asset retirement obligations have been inflated at 1.82% and discounted using a risk-free interest rate of 3.33% to arrive at the present value estimate of $84.2 million presented within the Company's consolidated financial statements as at December 31, 2024.
(4) Numbers may not add due to rounding.

The Company continues to look for additional resources both proximal to its Fox Creek assets and elsewhere within the WCSB. Key factors that the Company seeks in pursuing asset acquisitions include:

- strategic alignment with existing asset base;
- high-quality reserves with a low all-in cost per boe of recoverable resource (capital, operating, royalty, transportation and marketing costs) when compared with other opportunities;

- low-risk / high-reward upside potential from technology and operational effectiveness;
- adequate transportation of natural gas to existing markets or other locations which secondarily may also be suitable for construction of a potential power 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.

Midstream, Marketing and Transportation Arrangements

The Company's 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 anticipated growth of production and are described below.

Alliance Pipeline

The Alliance Pipeline is a 3,848-kilometer (2,391-mile) 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. The Company has extended its commitment on the US segment of the Alliance Pipeline until October 31, 2032, with anticipated toll renewals on the Canadian segment of the Alliance Pipeline for evergreen one-year terms starting November 1, 2025, with a longer term expectation of renewing for the full-term committed to on the US segment pending a review of tolls on the Canadian segment by the Canadian Energy Regulator. Kiwetinohk meets its contract obligation through the delivery of gas that it produces and gas acquired 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.

TC Energy

The Nova Gas Transmission Ltd. ("**NGTL**") system receives, transports and delivers natural gas within Alberta and connects to the 14,114 km (8,770 mile) mainline 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 (also owned by TC Energy Corporation) and other third-party pipelines. The Company acquired 1.1 mmcf/d of NGTL service effective May 1, 2021, which expired 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 negotiated an incremental 9.2 mmcf/d of firm service which commenced on August 1, 2023 in association with an interconnection to its Simonette 10-29 gas plant, expiring on July 31, 2031. As at December 31, 2024, the Company also had a firm service transportation agreement to deliver gas from the NGTL pipeline to its planned Opal power project with 8,000 GJ per day commencing September 1, 2024 for a period of seven years. This firm delivery agreement was acquired by the purchaser in connection with the February 4, 2025 sale of the Opal power project and the Company has no remaining liability as of March 4, 2025.

Pembina

This Pembina Peace Pipeline is owned and operated by Pembina and delivers crude oil, condensate, and natural gas liquids from northeastern British Columbia and northwestern Alberta to local processing hubs in Alberta. The Company’s two Simonette gas plants connect directly 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 condensate and NGL production 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 the Pembina Peace Pipeline. No take-or-pay commitments are associated with the pipeline but the agreement requires that the Company dedicate its condensate production in the region to this pipeline through a defined 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, 2032 (5)
Alliance	Transportation from Placid to Chicago	29.687 mmcf/d	Oct 31, 2032 (5)
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
NGTL	Transportation from Simonette to AECO	9.2 mmcf/d	Jul 31, 2031
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.
(2) The Company has extended its commitment on the US segment of the Alliance pipeline until October 2032, with evergreen renewals on the Canadian segment of the Alliance pipeline for one-year terms starting November 2025

Power Development Projects

The power business unit is advancing pre-construction development plans for an Alberta-based power generation project portfolio that currently includes solar, natural gas-fired power and CCS facilities. Successful development of Kiwetinohk's power projects is expected to enable the future production of reliable, dispatchable, affordable energy with lower GHG emissions intensity relative to electricity generated in Alberta currently (as measured against the 2023 Alberta Emissions Grid Displacement Factor). Given the evolving environment for development and operation of power generation facilities in Alberta, the Company is incurring only those development and general and administrative costs necessary to maintain its power projects position in the regulatory queue and position them for sale and or procurement of third party financing are being incurred.

As at December 31, 2024, the Company's seven project power development portfolio included gas-fired and solar projects with an expected total estimated nameplate capacity of approximately 2 GW as outlined below:

(1) Utility scale solar power,
  (a) 400 MW Homestead
  (b) 350 MW Granum
  (c) 170 MW Phoenix

(2) Natural gas-fired reciprocating engine plants, also known as gas-fired peakers, with the ability to quickly stabilize the portion of the power grid in response to rapid changes in demand or changes in supply from intermittent solar and wind generation equipment, and
  (a) 101 MW Opal (subsequently sold for $21.0 million on February 4, 2025)
  (b) 124 MW Little Flipi

(3) Utility scale natural gas combined cycle ("NGCC") power plants designed to be more efficient than existing coal power plant retrofits to gas-fired power and simple cycle gas-fired assets, and with opportunity to incorporate CCS.
   (a) 500 MW Black Bear
   (b) 500 MW Flipi

The Company's focus for its power development business during 2024 was on the sale and financing of the most advanced projects within its development portfolio.

On February 4, 2025, the Company closed the sale of 100% of its 101 MW Opal natural-gas fired power project for $21.0 million. The sale proceeds were used to reduce outstanding debt at the time of the transaction. The sale included all assets, material contracts, leases and permits relating to the Opal project, including the 8,000 GJ per day firm service transportation agreement with NGTL.

On February 28, 2025, Kiwetinohk's Homestead Solar project advanced to Stage 5 of the AESO regulatory process as a fully permitted and licensed project upon receiving approval for its proposed transmission line. As a result, Kiwetinohk is now required to place a $8.4 million deposit to satisfy its Generating Unit Owner’s Contribution (GUOC) requirement which was previously secured by a letter of credit. The GUOC must be paid before commencement of construction of the facilities required to connect a generating unit or aggregated generation facility, and is refundable subject to the satisfactory operation of the Homestead Solar project.Kiwetinohk expects to recover this deposit through ongoing efforts to sell and/or finance the Homestead project and has not allocated further capital towards developing its power portfolio at this time.

All projects within the power division development portfolio (excluding Homestead) were impaired during the second quarter of 2024 as a result of policy and regulatory uncertainty. Capital required to advance the Company's power projects to FID has not been allocated as part of the Company's 2025 budget and these projects remain immaterial to Kiwetinohk's overall business. The Company is not funding the capital required to construct projects and will seek external project equity, debt capital and/or proceeds of sales from remaining projects to fund the development of other projects in its portfolio.

Carbon Hubs - Carbon Capture and Storage

The Government of Alberta awarded Kiwetinohk licenses to advance planning on two carbon sequestration hubs for storing carbon dioxide. Kiwetinohk is reviewing carbon sequestration hubs and the feasibility of such hubs within Alberta. Kiwetinohk submitted the second annual Evaluation Agreement reports for its two carbon hubs on December 1, 2024. The Company believes all reporting requirements have been met, however a confirmation from Alberta Energy and Minerals had not been received as of the date of this AIF.

Employees

As of December 31, 2024, Kiwetinohk had 90 full time employees and 25 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, 2024
Calgary Office	69
Drayton Valley Field Office [1]	1
Grande Prairie Field Office	3
Simonette Assets	17
Total	90

Consultants Engaged in Full-Time Service	
Calgary Office	9
Placid assets	16
Total	25

1 - The Company has provided notice to terminate the Drayton Valley Field Office lease and expects the office to be closed on March 31, 2025 with no employees as of March 4, 2025.

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.

Health, Safety and Environment

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 Indigenous nations and 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. Indigenous and stakeholder awareness and responsiveness to expectations is a key component of the duties of all personnel in the service of Kiwetinohk. Kiwetinohk has staff health and safety expertise and contracts external consultants and services to provide it with expertise on health, safety, environmental and regulatory compliance issues, and to help it ensure appropriate safety precautions are implemented. Kiwetinohk's health, safety and environment program includes:

Emergency Response Planning

Kiwetinohk maintains an emergency response plan. In order to best prepare for emergencies, Kiwetinohk conducts an annual full-scale exercise, with additional field and tabletop emergency response exercises conducted throughout the year. Following the annual exercise, a debrief is conducted with participants to identify key learnings that can be adopted to increase Kiwetinohk's level of readiness. Kiwetinohk provides annual training for key responder roles throughout the year.

Alberta Certificate of Recognition (COR) Safety Program

Kiwetinohk participates in Alberta's COR Safety Program and received a COR certification in 2024. This certification demonstrates that Kiwetinohk's health and safety management system has been evaluated by a certified auditor and meets provincial standards, as established by Alberta Occupational Health and Safety.

Environmental Assessments and Audits

Environmental assessments are typically undertaken for new projects or when acquiring new properties or facilities to identify, assess and minimize environmental risks and operational exposures. Documentation is maintained to support internal accountability and measure operational performance against recognized industry indicators to assist in achieving the objectives of the Company's policies and programs.

The crude oil, natural gas and power development industries are currently subject to environmental regulations pursuant to municipal, provincial and federal legislation. 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 to evolve. Increased regulatory compliance costs or operational restrictions could result. Regulatory violations 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.

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

Kiwetinohk seeks to manage its environmental and operational impact through application of leading practices and a long-term strategy of co-location of natural gas, pipeline, power generation, and carbon management assets. The Company aims to reduce additional land and wildlife disturbance and manage the need for new infrastructure by prioritizing facilities in locations with existing infrastructure and access to markets. This includes finding opportunities to build partnerships and synergies with existing industries, companies, Indigenous nations and communities in the area to prevent waste and maximize value.

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, each well can be enabled to drain a larger area. By optimizing recovery and improving well design and longer subsurface laterals, well pads can be spaced more widely which reduces the land needed for roads, pipelines, power lines and the pads themselves.

Kiwetinohk believes it is in material compliance with applicable environmental laws as well as with local, provincial and federal environmental regulations, which serve as a baseline for its corporate performance. Kiwetinohk recognizes that all industrial activity has environmental impact and remains committed to meeting its responsibilities related to environmental risk management in all jurisdictions in which it operates.

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

Asset Retirement Obligations

As of December 31, 2024, Kiwetinohk had $114.0 million of uninflated, undiscounted asset retirement obligations including $34.4 million inactive and $79.6 million of active asset retirement obligations. The Company estimates it will incur an additional $30.5 million of asset retirement obligations associated with future development activities contemplated by the 2024 Reserves Report. The Company's current inactive and active asset retirement obligations have been inflated at 1.82% and discounted using a risk-free interest rate of 3.33% to arrive at the present value estimate of $84.2 million presented within the Company's consolidated financial statements as at December 31, 2024.

Methane Emissions

Kiwetinohk joined the OGMP 2.0, the flagship oil and gas reporting and mitigation program of the United Nations Environment Programme ("UNEP") in 2024. Kiwetinohk is the first Canadian member to join OGMP 2.0, the only comprehensive, measurement-based reporting framework for the oil and gas industry.

Kiwetinohk is advancing reductions in greenhouse gas emissions intensity from upstream natural gas production through a targeted focus on vented methane reductions. According to the Government of Canada, methane is a potent GHG with at least 28 times the warming potential of CO_2 over a 100-year period[1].

Kiwetinohk's upstream methane emissions are related to venting and flaring, which is strictly regulated in Alberta, and fuel combustion 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 methane strategy[2].

Fresh Water Use

Fresh water use, and disposal of process-affected water, is strictly regulated in Alberta. Kiwetinohk uses fresh water primarily in its drilling and completions activities associated with hydraulic fracturing of reservoirs and obtains water licenses for all its water use, by working with regulators and third-parties to manage water use within scientifically determined regional watershed thresholds, balancing operational needs with long-term resource availability.

Competitive Conditions

The facets of the North American energy business Kiwetinohk participates in, particularly upstream oil and gas and power development, 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 development, 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 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.

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 throughout the year. These seasonal variations provide an overarching influence on larger, longer-term economic trends which can effect the general level of oil and gas prices. For example, large North American supply increases resulted from the application and commercialization of horizontal well, multi-stage hydraulic fracture technology to very low permeability resources such as gas shales. 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.

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.

[1] Government of Canada. (n.d.). Reducing methane emissions. Environment and Climate Change Canada. Retrieved February 12, 2025, from https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/reducing-methane-emissions.html

[2] Government of Canada. (n.d) Faster and Further: Canada’s Methane Strategy. Retrieved February 13, 2025, from https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/reducing-methane-emissions/faster-further-strategy.html

INDUSTRY CONDITIONS

Companies operating in the oil and gas industries and in the development of renewable and natural-gas fired power projects are subject to extensive regulation and control of operations (including with respect to project approvals, land tenure, air emissions, water use, exploration, development, production, refining and upgrading, transportation, and marketing) as a result of legislation enacted by various levels of government. Kiwetinohk is further subject to the pricing and taxation of petroleum and natural gas through legislation enacted by, and agreements among, the federal and provincial governments of Canada, all of which should be carefully considered. All current legislation is a matter of public record and the Company is unable to predict what additional legislation or amendments may be enacted or repealed, particularly given possible changes in government with a federal election legislatively required in 2025.

The Company's assets and operations are regulated by administrative agencies deriving their authority from legislation enacted by the applicable level of government.

Outlined below are some of the principal aspects of the legislation, regulations, agreements, orders, directives and a summary of other pertinent conditions that impact the oil and gas and power generation industries in Western Canada, specifically in Alberta, where the Company's assets are primarily located. While these matters do not affect the Company's operations in any manner that is materially different than the manner in which they affect other similarly-sized industry participants with similar assets and operations, investors should consider such matters carefully. See "*Legal Proceedings and Regulatory Actions*".

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, 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 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.

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.

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.

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.

On December 14, 2024, the CER published the proposed Export Applications (Licences and Permits) Regulations, Export and Import (Orders, Licences and Permits) Regulations, and Export and Import Reporting Regulations. regarding import and export requirements, which are not currently in force. As such, the above requirements continue to apply. The deadline to submit written comments on the proposed regulations closed on January 28, 2025.

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.

The United States is implementing tariffs on all imports of Canadian goods which may include oil and natural gas imports as part of broader trade measures impacting energy markets. On February 1, 2025, U.S. President Donald Trump signed an executive order imposing tariffs of 25% on almost all goods imported from Canada, with a lower tariff of 10% imposed on Canadian energy and resources products including crude oil, natural gas, lease condensates, natural gas liquids and refined petroleum. These tariffs would affect the pricing structure for natural gas, crude oil and related products exported from Canada to the United States and alter the competitiveness of and market for Canadian oil and natural gas imports into the United States. In response, the Department of Finance Canada announced countermeasures with the imposition of 25% tariffs on certain goods imported from the U.S. On February 3, 2025, it was announced that the implementation of such announced tariffs would be suspended for 30 days.On March 4, 2025, the date of the AIF, the tariffs came into effect as initially promulgated. There remains substantial ambiguity regarding whether the tariffs will remain in place. Additionally, the precise effect of the tariffs on the Canadian economy and Canadian energy producers is yet to to be determined, but it is expected to have an adverse effect if the tariffs are maintained. See "*Risk Factors - Tariffs and Trade barriers including United States Tariffs*" for further information.

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, legal challenges, commercial and economic factors. Due in part to growing production and a lack of new and expanded egress infrastructure capacity, producers in Western Canada have experienced discounted commodity pricing relative to international markets in the last several years. Completion and start-up of both the expanded Trans Mountain Pipeline and Coastal Gas Link Pipeline should reduce the discount in commodity pricing by providing better access to international markets.

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.

Natural Gas

Natural gas prices in Alberta are constrained 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.

International Trade Agreements

Canada is party to a number of international trade agreements with other countries around the world that generally provide for, among other things, preferential access to various international markets for certain Canadian export products. Examples of such trade agreements include the CETA, the Comprehensive and Progressive Agreement for Trans-Pacific Partnership and, most prominently, the USMCA, which replaced the former NAFTA on July 1, 2020. Because the United States remains Canada's primary trading partner and the largest international market for the export of oil, natural gas and NGLs from Canada, the USMCA and any amendments, waivers or exceptions to it could impact Western Canada's oil and gas industry as a whole, including the Company's business.

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

Canada is also party to the CETA, which provides for duty-free, quota-free market access for Canadian crude oil and natural gas products to the European Union. Following the United Kingdom's departure from the European Union on January 31, 2020, the United Kingdom and Canada entered into the CUKTCA, which replicates CETA on a bilateral basis to maintain the status quo of the Canada-United Kingdom trade relationship.

While it is uncertain what effect CETA, CUKTCA or any other trade agreements will have on the petroleum and natural gas industry in Canada, the lack of available infrastructure for the offshore export of crude oil and natural gas may limit the ability of Canadian crude oil and natural gas producers to benefit from such trade agreements.

On March 4, 2025, United States imposed tariffs on nearly all goods imported from Canada. There remains substantial ambiguity regarding whether the tariffs will remain in place. Additionally, the precise effect of the tariffs on the Canadian economy and the Canadian energy producers is yet to to be determined, but it is expected to have an adverse effect if the tariffs are maintained. For more information on tariffs, see "*Exports of Crude Oil, Natural Gas and NGL from Canada*" and "*Risk Factors - Tariffs and Trade barriers including United States Tariffs*".

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 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 resulted in a deregulated and competitive wholesale electricity generation market with opportunities for investment in generation facilities by independent power producers.

The development of new generating capacity in Alberta is currently 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 and is dispatched in accordance with an economic merit order administered by the AESO. However, the electricity market in Alberta is presently undergoing extensive restructuring, resulting in significant market uncertainty. See "*Legal and Regulatory Regime – Power Industry – Alberta*".

Alberta Electricity Market Changes

The Alberta Interconnected Electric System is comprised primarily of natural gas and renewable energy with remaining power demand allocated to import/export capacity. In May 2024, the AESO published a long-term outlook[3] for the province with an expectation that Alberta's energy consumption will to continue to grow, with natural gas expected to emerge as the leading dispatchable and transitional fuel source. This expected growth outlines a need for continued development of new power projects in the province. Alberta is positioned to continue to electrify industrial sectors and attract the development of new data center investments due to, among other things, its power market structure and access to natural gas supply. If the province is successful in attracting data centers to Alberta, there is the potential for further accelerated demand for natural gas production and power.

Kiwetinohk is uniquely situated to take advantage of this forecasted growth in demand with 87.0 mmcf/d of natural gas production during 2024, and approximately 2 GW of power currently under development within the AESO regulatory queue.

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 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

[3] Alberta Electric System Operator. (2024). 2024 Long-Term Outlook. Retrieved from https://www.aeso.ca/assets/Uploads/grid/lto/2024/2024-LTO-Report-Final.pdf

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.

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).

In *Yahey v British Columbi*a, released June 29, 2021, the British Columbia Supreme Court held that British Columbia breached the Blueberry River First Nations' 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 Nations' traditional territory. The Blueberry River First Nations' traditional territory overlaps with some areas of the Montney formation. The court ruled that British Columbia could no longer authorize industrial development on the Blueberry River First Nations' traditional territory if such development would breach the First Nations' treaty rights. The *Yahey* decision was suspended for six months to allow British Columbia and the Blueberry River First Nations to negotiate changes to the regulatory regime that would align with the findings of the court.

On January 23, 2023, British Columbia and the Blueberry River First Nations entered into the Blueberry River First Nations Implementation Agreement, through which the parties agreed to a number of transitional measures while they negotiated more permanent means to balance treaty rights with economic development. However, on July 8, 2024, the Blueberry River First Nations filed a claim against the Province of British Columbia, alleging the first implementation plan made under that Agreement was in breach of the Agreement itself. In its response filed August 2, 2024, the Province denies the Blueberry River First Nations’ allegations.

Both before and since Yahey was released, First Nations across Canada have filed similar claims against the provinces in which they reside, including in Alberta, Saskatchewan, and Ontario.

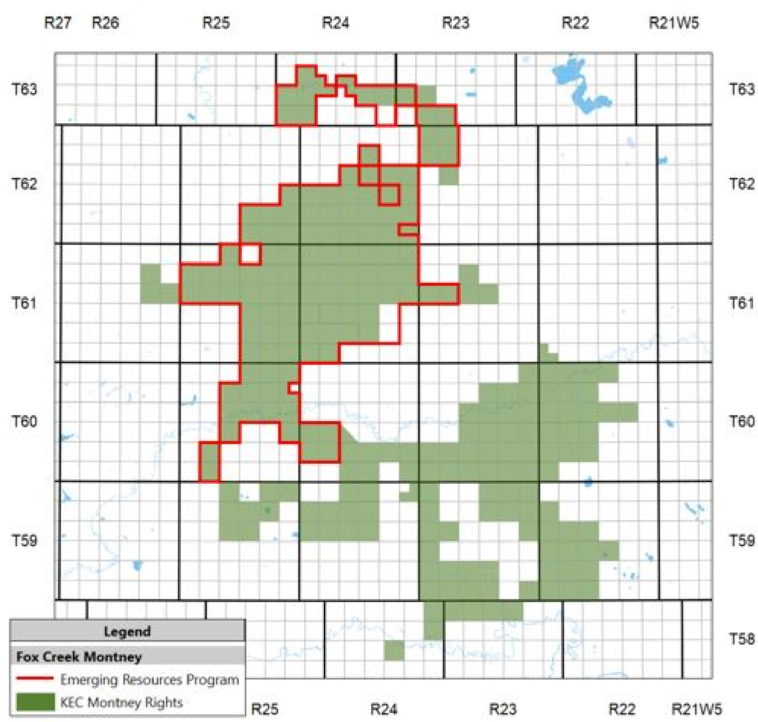
Specific to Alberta, four First Nations have filed claims against the Province of Alberta around the cumulative impacts of industrial development within their territories on their treaty rights: Beaver Lake Cree Nation, Duncan’s First Nation, Athabasca Chipewyan First Nation and Siksika First Nation. The impact of these lawsuits will not be known until they are adjudicated or otherwise resolved, the timeline for which is uncertain.

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 ("ERP"). Applications to that program closed after December 31, 2024. Kiwetinohk did not apply for a new ERP ahead of the deadline. Kiwetinohk does however have an existing, approved ERP scheme in place encompassing approximately 119 sections of the Fox Creek Montney rights within the Simonette Assets. The Fox Creek Montney rights held by the Company are shown on the map below, with the approved project area outlined in red. The approved project has a seven year term from the date of the initial application. Kiwetinohk is entering the sixth year of its term on March 31, 2025 and enrolled eligible wells will have until 2032 to deplete the remaining benefits under the 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, 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 IAA replaced the CEAA 2012. As part of the regulatory transition, the IAAC replaced the Canadian Environmental Assessment Agency.

The enactment of 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 CER has assumed the jurisdiction of the 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.

In 2022 the Alberta Court of Appeal released a reference opinion with the majority finding the IAA to be unconstitutional. This decision was subsequently referred to the Supreme Court of Canada, and on October 13, 2023, the Supreme Court of Canada released its opinion with the majority finding that the IAA was unconstitutional in part.

The Supreme Court unanimously held the portion of the IAA addressing projects carried out or financed by federal authorities on federal lands or outside Canada is constitutional, however, the majority determined the “designated projects” component of the IAA to be unconstitutional as it exceeded federal legislative authority by regulating projects in entirety rather than limiting the assessment to areas within federal authority, and due to the IAA defining effects within federal jurisdiction too broadly.

As a result the Government of Canada made amendments to the IAA through the Budget Implementation Act ("BIA"). On June 20, 2024, the BIA received Royal Assent and the amended IAA was issued with amendments and clarity on decision-making in impact assessments on areas of federal jurisdiction and increased flexibility to cooperate with other jurisdictions.

On November 20, 2024, the Government of Alberta sought a reference on the amended IAA, asking the Alberta Court of Appeal to opine on whether the IAA and its regulations are beyond federal legislative authority and whether, in the alternative, the amended legislation would be inapplicable to the extent that its application would impair provincial legislative power.

With a federal election legislatively required in 2025, it is unclear whether any change in federal government would result in further amendments to the IAA.

On June 21, 2021, the 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 UNDRIP; align federal laws with UNDRIP; and prepare annual reports on progress. Canada’s 2023-2028 Action Plan was released in June 2023 and included 131 measures intended to provide a roadmap of actions Canada needs to take in partnership with Indigenous peoples to implement the principles and rights set out in the UNDRIP and to further advance reconciliation in a tangible way. The practical consequences of this Action Plan remain unclear.

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 *Oil and Gas Conservation Act* (Alberta), 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 AUC and the Alberta Land and Property Rights Tribunal (formerly the Surface Rights Board), as well as the Alberta Ministry of Energy and Minerals' responsibility for mineral tenure.

The Government of Alberta relies on regional planning to accomplish its resource development goals. Its approach to natural resource management provides for engagement and consultation with stakeholders and the public and examines the cumulative impacts of development on the environment and communities. While the AER is the primary regulator for energy development, several other governmental departments and agencies may be involved in land use issues, including the Alberta Ministry of Environment and Protected Areas, the Alberta Ministry of Energy and Minerals, the Aboriginal Consultation Office and the Land Use Secretariat.

The Alberta 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, among other industrial activities including fluid disposal operations. 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 where it occurs.

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 or in relation to certain disposal wells deemed to be seismogenic (see AER Directive 065: Resources Applications for Oil and Gas Reservoirs, updated November 12, 2024). The AER has implemented specific requirements via Subsurface Order Nos. 2A, 6, and 7 in regions with seismic protocols in place, being 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.

Licensee Life-Cycle Management in Alberta

The AER administers Licensee Life-Cycle Management through Directive 88 ("Directive 88") which governs most conventional upstream crude oil and natural gas wells, facilities and pipelines.

Directive 88 applies at all phases and throughout the life cycle of energy development and includes: (a) a holistic assessment of the licensee's capabilities and performance (b) the LCA; (c) the LMP, (d)the IRP; and (e) the application requirements related to the licence transfer process.

Importantly, companies operating in Alberta's crude oil and natural gas industry are required to make mandatory annual minimum payments towards outstanding reclamation obligations. The reclamation annual spend targets came into effect on January 1, 2022 through the Inventory Reduction Program and are set annually. Among other things, Directive 88 states that all AER license transfer applications will trigger a holistic assessment of the transferor and transferee.

Security requirements previously contained in a former version of Directive 88 have been moved to Directive 068: Security Deposits, which provides direction regarding the calculation, collection, and use of security deposits under the *Oil and Gas Conservation Rules*, *Geothermal Resource Development Rules*, and *Brine-hosted Mineral Resource Development Rules*, as well as the cash and letters of credit required to be provided to the AER to satisfy security deposit requirements under the energy resource enactments, including their form, use, and refund.

Accountability and Transparency

In 2015, the Government of Canada's 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.

In May 2023, the Government of Canada's *Fighting Against Forced Labour and Child Labour in Supply Chains Act* was passed and came into effect January 1, 2024. The legislation imposes obligations to report steps taken during the previous financial year to prevent and reduce the risk of child labour or forced labour being used by the Company or in the Company's supply chains. Reports will be submitted to the government and made available to shareholders and filed on SEDAR+ along with the Company's annual financial statements prior to March 31 of each year.

Power Industry in Alberta

The development, construction and operation of power projects are subject to federal, provincial and/or local laws, rules, regulations and guidelines generally in place to 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.

The AUC, among other things, reviews applications for proposed power generation facility developments and electrical interconnections for power projects to determine if they are in the public interest and should be approved. The AUC is responsible for approving the AESO - the trade name for Alberta's Independent System Operator ("**ISO**") - rules. AEPA evaluates wildlife and habitat risks of renewable projects, and reviews and approves industrial applications for gas-fired power projects.

In March 2024, the Alberta Minister of Affordability and Utilities indicated that future market reforms would be introduced to promote grid reliability and affordability. At the same time, the Minister announced the release of reports by the AESO and MSA recommending a restructured energy market ("**REM"**) to achieve "stronger incentives for dispatchable generation, lessen the impacts of market power, and provide long-term signals for investment to promote grid reliability within the province." Following from the recommendations from the AESO and the MSA, the Province announced the *Market Power Mitigation Regulation*, which implemented a secondary offer cap on thermal offers of market participants with a five per cent or greater market share once a certain net revenue threshold has been reached in a month. The *Market Power Mitigation Regulation* is intended to be replaced once the REM is implemented by the end of 2025, following REM consultations.

On July 3, 2024, the Minister directed the AESO in respect of key details regarding the REM design elements and forthcoming changes to transmission policy which include: a mandatory day-ahead market; market-based pricing with market power mitigation measures; a province-wide uniform price; shorter settlement intervals; a review of the price floor and ceiling; and Security Constrained Economic Dispatch with co-optimization of energy and ancillary services.

On December 10, 2024, the Minister further directed the AESO to continue the REM technical design, subject to additional government decisions with respect to congestion management, stakeholder engagement, the development of an energy pricing framework, and collaboration on an AUC-led initiative to implement five-minute settlement intervals by 2032 for transmission-connected loads, generators and interties, and by 2040 for all loads. At the same time, the Minister directed the AESO to introduce key reforms to the ISO Tariff under the Transmission Regulation. Stakeholder consultation in respect of the REM and transmission policy reforms is ongoing. The REM design is to be finalized and implemented at the end of 2025, leading to significant uncertainty in the sector.

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, natural gas, and power industries 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 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 and the Paris Agreement entered into force on November 4, 2016.

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 a backstop federal carbon pricing framework establishing minimum national standards for stringency in respect of greenhouse gas emissions pricing, with coverage of those provinces and territories that do not maintain an equivalent carbon pricing regime.

On June 21, 2018, the Government of Canada enacted the GGPPA, which introduced the backstop federal carbon pricing framework. This system applies in those provinces and territories that request its coverage, and in those that do not have comparable emissions pricing regimes meeting the federal standards in effect. The general 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 greenhouse gas emissions across the country. The GGPPA pricing framework operates through two complementary systems: a charge for various prescribed fuel sale and usage events (the "consumer" carbon levy) and an output-based pricing system which sets emissions intensity standards for large industry and emissions-intensive trade-exposed industries.

As of the date of this AIF, the GGPPA maintains a carbon levy at a rate of $80 per tonne of CO2e of emissions, increasing by $15 on April 1 of each year (the next scheduled increase being April 1, 2025) to a maximum levy rate of $170 per tonne of CO2e of emissions in 2030. The proposed increases in the rate of carbon levy in 2030 relate 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 legislation enforces 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 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 2023 the federal government published draft regulations to bring total methane emission reductions to 75% by 2030 compared with 2012 levels.

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.

In June 2022, the Government of Canada enacted Clean Fuel Regulations under the *Canadian Environmental Protection Act, 1999* (Canada). Pursuant to the Clean Fuel Regulations, fuel producers, importers and distributors are required to reduce the emissions intensity of gaseous, liquid and solid fuels by approximately 15% (below 2016 levels) by 2030.

Clean Electricity Regulations

The Clean Electricity Regulations ("CER") under the Canadian Environmental Protection Act, 1999, came into force on January 1, 2025.

Beginning in 2035, the CER will set limits on carbon dioxide pollution from all electricity generating units that combust fossil fuels, have a generating capacity equal to or greater than 25 MW, and are connected to a regulated electricity grid (with limited exemptions).

The CER limit emissions using an annual emissions limit in tonnes of carbon dioxide per year based on each unit's electricity generation capacity. Under the CER, an operator can exceed a unit's annual emissions limit up to a certain amount if the operator remits an equivalent amount of eligible greenhouse gas offset credits.

The date from which electricity generating units will be subject to the CER depends on their commissioning date and other criteria, and generally fall into three categories. Units commissioned prior to 2025 have 25 years from when they were commissioned before they are subject to an annual emissions limit. Units are "planned" if they meet specific criteria by December 31, 2025, are under construction by December 31, 2027, and are commissioned by December 31, 2034. Planned units can operate without an annual emissions limit until the end of 2049. Any unit commissioned on or after January 1, 2025, that is not a "planned unit" will be subject to an annual emissions limit beginning in 2035 or on the date they are commissioned, if commissioned after 2035.

The CER also include provisions for pooling units or transferring compliance credits among facilities, banking of compliance credits, and set out rules and criteria for various end of prescribed life categories.

The Alberta Government opposes the CER and has indicated it intends to challenge them on constitutional grounds upon their enactment.

Oil and Gas Emissions Cap

In November 2024, the Government of Canada published Canada Gazette, Part I, Volume 158, Number 45, *Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations* to support reducing emissions from the oil and gas sector to 35% below 2019 emissions levels by 2030. The cap is based on data reported by operators in 2026, with the cap phased in starting in 2026. If compliance flexibilities, including decarbonization credits and offsets in the proposed cap and trade system, were maximized, the sector could emit up to a legal upper bound estimated to be 19% below 2019 levels. if enacted following the 2025 federal election, the proposed regulations could come into force on January 1, 2026, with final regulations expected in late 2025.

The Alberta Government opposes the proposed *Oil and Gas Sector Greenhouse Gas Emissions Cap Regulations* on the basis they are unconstitutional.

Methane Emissions Reductions

On December 16, 2023, Canada proposed *Regulations Amending the Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* ("**Proposed Amendments**") that would build on the existing *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* to reduce upstream oil and gas methane emissions through the introduction of emission standards and work practices to inspect sites and make repairs. The Proposed Amendments are designed to help reduce the sector's methane emissions by at least 75% by 2030, relative to 2012 emissions.

The Proposed Amendments would also introduce a new performance-based compliance option designed to focus on emissions outcomes, and would apply to upstream, midstream, and transmission facilities in Canada's onshore oil and gas sector. The Proposed Amendments set out different requirements based on the size and type of equipment at sites, allow options for site monitoring requirements, and phase in the application of requirements for certain facilities. The public consultation period for the Proposed Amendments closed on February 14, 2024.

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 federal *Regulations Respecting Reduction in the Release of Methane and Certain Volatile Organic Compounds (Upstream Oil and Gas Sector)* will not apply in Alberta.

Competition Act Update

In June 2024, new provisions were added to Canada's *Competition Act* that explicitly target greenwashing by requiring businesses to support their claims about the environmental benefits of products or business activities with adequate and proper testing or substantiation. The Competition Act is administered and enforced by the Competition Bureau, an independent agency. Starting on June 20, 2025, changes will allow private parties to take enforcement action under the Competition Act.

On December 23, 2024, the Competition Bureau published a draft of its proposed guidelines regarding environmental claims that inform its interpretation and enforcement approach. Public consultations on the proposed guidelines are open until February 28, 2025. The final guidelines will not have the force and effect of law, including on private parties that may choose to start legal proceedings against businesses.

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 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.

Global Economic and Financial Conditions and Commodity Prices

The Company’s revenue, profitability, cash flow and future rate of growth are highly dependent on commodity prices, which are volatile and may fluctuate widely in response to relatively minor changes in the supply of, and demand for, petroleum and natural gas. The factors that may influence commodity prices are outside of the Company’s control, and include market expectations with respect to the supply of and demand for commodities; production and inventory levels of such commodities; volatility and trading patterns in the commodity futures market; the proximity, capacity and cost of pipelines and other transportation infrastructure; weather conditions affecting supply and demand; political conditions, instability and hostilities, including conflicts in the Middle East, Eastern Europe and elsewhere; sanctions imposed on certain oil producing nations; the actions of OPEC and other state-controlled oil companies; currency fluctuations; social attitudes and policies affecting energy consumption and energy supply; shareholder activism; the price, availability and acceptance of alternative energies, including renewable energy; and overall domestic and global social, economic and political conditions. A material decline in commodity prices could result in a reduction in the Company's cash flows, its operations and the volume and value of its reserves.

Substantial Capital Requirements

The Corporation's access to capital may be limited or restricted as a result of factors related and unrelated to it, impacting its ability to conduct future operations and acquire and develop reserves or fund investment in its power business. The Corporation anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. As future capital expenditures will be financed out of cash generated from operations, borrowings and possible future equity sales, the Corporation's ability to do so is dependent on, among other factors:

(1) the overall state of the capital markets;
(2) the Corporation's credit rating;
(3) commodity prices;
(4) interest rates;
(5) royalty rates;
(6) tax burden due to current and future tax laws; and
(7) investor appetite for investments in the energy industry and the Corporation's securities in particular.

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

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. 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.

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:

(1) 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;
(2) relatively long pilot production test times to determine commerciality or optimal practices, as compared to conventional crude oil and natural gas fields;
(3) 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;
(4) 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;
(5) difficulties associated with extreme weather conditions including potential freezing;
(6) more wells per section in some instances than is possible to optimally and cost-effectively develop reserves;
(7) reduced wellhead pressures needed for production, leading to larger flow lines or additional compression;
(8) complexity of development of multiple productive zones; and
(9) failure to realize anticipated benefits from the application of unconventional drilling techniques.

Hydraulic Fracturing and Seismic Activity

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 seismicity 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 goals for its undeveloped land holdings in a region could be lost in whole or in part.

Political Uncertainty

The Company's results can be adversely impacted by political, legal or regulatory developments in Canada and globally that affect local operations, local markets or international markets. Changes in government, government policy or regulations, changes in law or to the interpretation of settled law, third-party opposition to industrial activity and the duration of regulatory reviews could impact the Company's operations and projects. A change in federal, provincial, state or municipal governments in Canada or the United States may have an impact on the directions taken by such governments on matters that may impact the energy industry, including the balance between economic development and environmental policy.

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 and regulations 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. These regulations are subject to change based on current and future economic or political conditions.

Kiwetinohk's business plans for its power business unit are built on the premise that markets are seeking energy in a form that can be used with reduced associated emissions of GHGs relative to the current situation. In many cases, the extent of these reductions will depend on government policies and 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's power business unit to attain profitable opportunities.

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.

Tariffs and Trade Barriers including United States Tariffs

Ongoing geopolitical tensions, particularly between major economies like the United States and China have led to trade restrictions or tariffs on oil and gas. On March 4, 2025, the United States imposed tariffs on Canadian products imported to the US, including oil and gas imports. The precise effect of the tariffs on the Canadian economy and the Canadian energy producers is yet to to be determined, but it is expected to have an adverse effect if the tariffs are maintained. Tariffs may disrupt trade, increase energy costs, and strain United States and Canadian relations. Canada may retaliate with tariffs on U.S. exports, or add additional tariffs to Canadian exports, which could further exacerbate trade tensions and potentially escalate into a broader trade war, further impacting the economy and destabilizing the oil and natural gas market. Tariffs may increase investor uncertainty, deterring further investment and capital expenditures on the Company's upstream development projects.

Trade restrictions and tariffs may materially adversely affect the commodity prices received by Kiwetinohk and its production levels as well as decreasing the available markets for its products, disrupting its supply chains and increasing the cost of the goods purchased by it. Trade restrictions and tariffs may also increase volatility in, or have an adverse impact on, exchange rates and interest rates. Such potential circumstances or impacts may have a material adverse effect on Kiwetinohk's business, financial condition, results of 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 power development 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.

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.

Restrictions on Development 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 development 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.

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.

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 and 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.

Risks Associated with Developing the Power Generation Business

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

The Company's strategy for developing a power business unit is to develop high-quality natural gas and renewable power generating facilities that have the potential to generate sustainable cash flows and provide an attractive risk-adjusted return on invested capital. The Company will seek to dispose of such projects prior to commercial operations or otherwise seek third party financing. 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, nor is there any assurance that the Company will be able to identify purchasers or financiers of its projects. 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 or plans to operate such business upon which an investor can evaluate such business and performance and base its investment decision.

The successful execution of the Company's power business unit strategy requires careful timing and business judgment and access to the capital providers and/or potential purchasers of the Company's projects, 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 power business unit 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:

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

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

(3) 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);

(4) 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;

(5) unforeseen engineering and environmental problems;

(6) 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

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

Ability to Achieve Power Business Unit 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 for its power business unit. 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:

(1) cost-effectiveness of renewable energy technologies as compared with conventional and competitive technologies;
(2) performance and reliability of renewable energy products as compared with conventional and non-renewable products;
(3) fluctuations in economic and market conditions that impact the viability of conventional and competitive alternative energy sources;
(4) increases or decreases in the prices of oil, natural gas and electricity; and
(5) availability or effectiveness of government subsidies and incentives.

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 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.

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.

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.

Inflation and Cost Management

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.

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

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

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 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 the COVID-19 pandemic), 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 pipelines, 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 development 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 Company's ability to develop its projects and the profitability of those 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.

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 CCS 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:

(1) shortages of skilled workers, including executive, technical and operating personnel;
(2) shortages of equipment and materials required by the oil and gas sector, as manufacturers and suppliers withdraw from the industry; and
(3) 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.

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 to 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.

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.

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.

Drought and low water levels 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.

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.

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:

(1) natural control data such as petrophysical and geomechanical data derived from well logs and cores and pressure surveys; and
(2) 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.

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 the Company's ability to develop its 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 the Company's requests for permits or successful challenges or appeals to permits issued to the Company 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 power development projects 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.

The social acceptance by local stakeholders, including, in some cases, First Nations and other Indigenous peoples, and local communities is critical to the Company's 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.

Reputational Risk Associated with Kiwetinohk’s Operations

Kiwetinohk's business, operations or financial condition may be negatively impacted as a result of any negative public opinion towards the Company or as a result of any negative sentiment toward, or in respect of, its reputation with stakeholders, special interest groups, political leadership, the media or other entities. Public opinion may be influenced by certain media and special interest groups' negative portrayal of the industry in which the Company operates as well as their opposition to certain oil and natural gas projects. Potential impacts of negative public opinion or reputational issues may include delays or interruptions in operations, legal or regulatory actions or challenges, blockades, increased regulatory oversight, reduced support for, delays in, challenges to, or the revocation of regulatory approvals, permits and/or licenses and increased costs and/or cost overruns. The Company's reputation and public opinion could also be impacted by the actions and activities of other companies operating in the oil and natural gas industry, particularly other producers, over which Kiwetinohk has no control. Similarly, 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. Developing a reputation of having an unsafe work site could impact Kiwetinohk's ability to attract and retain the necessary skilled employees and consultants to operate its business. Opposition from special interest groups opposed to oil and natural gas development and the possibility of climate related litigation against governments and hydrocarbon companies may impact Kiwetinohk's reputation. There may also be allegations 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.

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 CO2 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 CCS 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 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 of its power generating projects. There are numerous development projects to be advanced in the coming years that will result in competition for capital. Additionally, the Company’s business deals in commodities: oil, natural gas liquids, condensate, natural gas and potentially electricity, and carbon dioxide. 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.

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.

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

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 that affect the Company's activities. 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 renewable 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.

Changing Investor Sentiment

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

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.

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.

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 CCS. 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 $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 Canadian income taxes during the year ended December 31, 2024. 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 2025 and the Company will begin to be taxable late in 2026. 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 future cash tax horizon to occur sooner than its current projection on owned assets. In particular, the Company's anticipated future cash tax horizon is subject to risks pertaining to changes in its capital expenditures, operations, growth, capital expenditures, asset base, acquisitions, corporate structure or changes to tax legislation, regulations or interpretations, and its growth. In the event that the Company becomes cash taxable sooner than projected or it is unable to lengthen the cash tax horizon through the acquisition and development of additional growth projects and related tax pools. The Company's cash available for distribution and its dividend (should it determine the future to make distributions or pay dividends) could decrease, which would in turn have a material adverse effect on the value of its common shares. See "*The Company has no plans to pay dividends"*.

Uncertainty of Development Projects

The Company's portfolio includes development 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.

Project Construction and Execution

The Company expects to manage a variety of small and large projects. 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 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 of power generation 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.

Additionally, the Company may have difficulty accessing power grid capacity for its planned power generation projects. 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 is seeking approval to build deep brine aquifer carbon dioxide storage in association with its CCS 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.

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.

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.

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 2024 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.

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.

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.

International Conflict: Russia - Ukraine, Israel - Gaza, Yemen's Houthi Rebels

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.

On October 7, 2023, a Palestinian militant group, Hamas, launched an assault on Israel with gunmen infiltrating communities near the Gaza Strip. Israel responded with air and artillery strikes. Although this does not directly impact oil supply, the conflict is near to the Persian Gulf and major international shipping corridors.

Since November 2023, Yemen's Houthi rebels, acting as part of "the Axis of Resistance," an Iran-backed military coalition, have repeatedly attacked ships transiting the Red Sea, including oil tankers. A United States-led mission is increasing security presence in the region to support international vessel traffic. This conflict has resulted in increased shipping costs to various business entities. Continued attacks may result in further increases in shipping costs, longer transit times and delays in delivering products and procuring supplies.

The implications of these and other potential future conflicts are difficult to predict with any certainty, and there remains uncertainty as to the direct or indirect impacts that such conflicts may have for the Company. Each such conflict could have a material and adverse effect on the business, financial condition and operations of the Company. Depending on the severity of such events, a number of other risks to the Company may be heightened.

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 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 renewable energy projects largely depends upon the increased use and widespread adoption and demand for renewable 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 renewable energy technologies as compared with conventional and competitive technologies; performance and reliability of renewable 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 power development project portfolio.

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.

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.

While the effects of the COVID-19 pandemic have lessened, the extent to which future pandemics may impact Kiwetinohk is uncertain. It remains possible that subsequent waves or additional variants of CSA51-324 or future pandemics may have a material adverse effect on general economic conditions as well as Kiwetinohk's business, results of operations and financial condition. 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.

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 62.9% and 11.9%, respectively, of the Company's issued and outstanding Common Shares. As a result, ARC will have the ability to control (or veto) certain matters submitted to the Company's shareholders for ordinary approval, including without limitation, the election and removal of directors. In addition, ARC will more than likely effectively have the ability to approve (or veto) a corporate sale or business combination transaction (if it is not a “related party transaction” with ARC) as the approval threshold for such transactions is typically the approval by the holders of 2/3 of the Common Shares voted on the matter and ARC’s 62.9% shareholdings could represent more than 2/3 of the Common Shares voted in respect of such a transaction. 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.

Expiration of Leases

The Company, or its working interest partners, may fail to meet the requirements of a lease, causing its termination or expiry. The Company's properties are held in the form of leases and working interests in leases. If the Company, or the holder of the lease, fails to meet the specific requirement of the lease, the lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each lease will be met. The termination or expiration of the Company's leases or the working interests relating to a lease and the associated abandonment and reclamation obligations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

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.

Intellectual Property Litigation

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

Insufficiency of Internal Controls

The Company has had a significant amount of growth and change in recent years 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 diversity, sophistication and volume of attacks, including as a result of emerging technologies such as artificial intelligence, 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

Security requirements previously contained in a former version of Directive 88 have been moved to Directive 068: Security Deposits (“**Directive 68**”), released on February 7, 2025, which provides direction regarding the calculation, collection, and use of security deposits under the *Oil and Gas Conservation Rules*, *Geothermal Resource Development Rules*, and *Brine-hosted Mineral Resource Development Rules*, as well as the cash and letters of credit required to be provided to the AER to satisfy security deposit requirements under the energy resource enactments, including their form, use, and refund.

Directive 68 does not apply to security programs administered under the specified enactments, such as the Mine Financial Security Program, which is a liability management program under the *Environmental Protection and Enhancement Act*.

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 67: Eligibility Requirements for Acquiring and Holding Energy Licences and Approvals ("**Directive 67**") may impact acquisitions and dispositions by oil and gas companies, including the Company. Given the recent release of liability management framework policy components, there is uncertainty about how the new regime will be 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 and exploration and development in the Montney and Duvernay plays. The Company expects that its future operations will include, 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 through the payment of dividends.

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 term "boe" 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) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from 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 tight oil, NGL 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 tight oil, NGLs 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 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, peak 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.

Unless otherwise specified, references to production are on a gross basis.

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 tight oil, shale gas and NGL reserves of the Company as evaluated in the 2024 Reserves Report.

The 2024 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 2024 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 2024 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 2024 Reserves Report from which the data below is derived has a preparation date of March 4, 2025 and evaluated the reserves attributable to Kiwetinohk as at December 31, 2024.

The reserves data summarizes the shale gas, NGL and tight 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 2024 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 2024 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.

2024 Reserves Report

The tables below summarize the data contained in the 2024 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, 2025), as set forth below.

Summary of Reserves (Forecast Prices and Costs)

Summary of Reserves
As of December 31, 2024 — Forecast Prices and Costs

Reserves Category	Tight Oil		Shale Gas		Natural Gas Liquids [3]		Total	
	Gross [1] Mbbl	Net [2] Mbbl	Gross [1] MMcf	Net [2] MMcf	Gross [1] Mbbl	Net [2] Mbbl	Gross [1] Mboe	Net [2] Mboe
Proved								
Developed Producing	690.6	540.3	147,891.7	137,567.4	18,662.8	15,380.8	44,002.0	38,849.0
Developed Non-Producing	0.0	0.0	5,315.6	5,017.8	577.9	480.2	1,463.8	1,316.5
Undeveloped	0.0	0.0	263,099.0	244,043.1	41,351.2	35,348.0	85,201.0	76,021.8
Total Proved [4]	**690.6**	**540.3**	**416,306.2**	**386,628.2**	**60,591.8**	**51,209.0**	**130,666.8**	**116,187.4**
Total Probable	**147.8**	**107.5**	**378,269.7**	**339,943.3**	**52,512.0**	**40,213.7**	**115,704.7**	**96,978.4**
Total Proved + Probable [4]	**838.4**	**647.9**	**794,575.9**	**726,571.5**	**113,103.8**	**91,422.7**	**246,371.5**	**213,165.8**

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 33% and pentanes plus represents 3% on a volume basis for Total Proved reserves, and 32% 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, 2024 – 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	995,821.3	895,776.1	783,867.9	698,306.9	633,368.2	20.18
Developed Non-Producing	24,334.7	20,378.8	17,142.0	14,603.9	12,613.3	13.02
Undeveloped	1,852,467.3	1,242,568.6	866,521.9	621,466.5	454,147.7	11.40
Total Proved [3]	**2,872,623.3**	**2,158,723.5**	**1,667,531.8**	**1,334,377.3**	**1,100,129.2**	**14.35**
Total Probable	**3,404,591.2**	**1,905,105.7**	**1,193,179.4**	**812,222.7**	**588,388.1**	**12.30**
Total Proved + Probable [3]	**6,277,214.5**	**4,063,829.1**	**2,860,711.1**	**2,146,600.0**	**1,688,517.3**	**13.42**

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, 2024 – 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	951,942.4	865,899.3	762,661.2	682,730.1	621,597.8
Developed Non-Producing	18,381.9	15,661.8	13,317.2	11,444.1	9,962.3
Undeveloped	1,423,610.8	923,661.7	616,938.9	419,105.6	285,859.3
Total Proved [3]	**2,393,935.1**	**1,805,222.8**	**1,392,917.3**	**1,113,279.9**	**917,419.4**
Total Probable	**2,625,404.2**	**1,448,307.0**	**893,148.9**	**599,710.4**	**429,823.5**
Total Proved + Probable [3]	**5,019,339.3**	**3,253,529.8**	**2,286,066.2**	**1,712,990.3**	**1,347,242.9**

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, 2024 Forecast Prices and Costs

Reserves Category	Revenue [1] M$	Royalties [2] M$	Operating Costs [3] 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]	7,955,712	898,080	2,197,401	1,775,764	211,844	2,872,623	478,688	2,393,935
Total Proved + Probable [5]	15,787,525	2,205,683	4,108,656	2,948,399	247,572	6,277,215	1,257,875	5,019,339

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. The costs shown are the estimated future costs (current costs inflated at 2% per year)
(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, 2024 Forecast Prices and Costs

Reserves Category	Product Type	Future Net Revenue Before Income Taxes [1, 2] (discounted @ 10%) M$	Unit Value [3] $/bbl $/Mcf
Total Proved Reserves [4]	Tight Oil (Including Solution Gas and By-products	35,746	66.16
	Shale Gas (Including By-products)	1,631,786	4.30
	Total	**1,667,532**	
Total Proved + Probable [4]	Tight Oil (Including Solution Gas and By-products	40,983	63.26
	Shale Gas (Including By-products)	2,819,728	3.93
	Total	**2,860,711**	

(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, 2025 ("Jan 2025 3 Consultant Avg.") price forecast.

Summary of Pricing and Inflation Rate Assumptions
As of January 1, 2025 Forecast Prices and Costs

	Crude Oil Price Forecasts							Liquids Price Forecasts				Natural Gas Price Forecasts			
	WTI Crude Oil	Brent Crude Oil	Edmonton Light Crude Oil	Bow River Hardisty Crude Oil	Canadian Select Crude Oil	Alberta Heavy Crude Oil	Sask Cromer Medium Crude Oil	Edmonton Ethane	Edmonton Propane	Edmonton Butanes	Edmonton Cond. & Natural Gasolines	U.S. Henry Hub Gas Price	Alberta AECO Spot Price	Inflation	US/CAN Exchange Rate
Year	$US/bbl	$US/bbl	$C/bbl	$C/bbl	$C/bbl	$C/bbl	$C/bbl	$C/bbl	$C/bbl	$C/bbl	$C/bbl	$US/ MMBtu	$C/ MMBtu	%	$US/ $CAN
	(1)	(2)	(3)	(4)	(5)	(6)	(7)						(8)	(9)	(10)
2025	71.58	75.58	94.79	83.89	82.69	75.85	91.15	7.54	33.56	51.15	100.14	3.31	2.36	0.0	0.712
2026	74.48	78.51	97.04	86.45	84.27	77.56	93.35	10.76	32.78	49.99	100.72	3.73	3.33	2.0	0.728
2027	75.81	79.89	97.37	85.50	83.81	77.12	93.62	11.32	32.81	50.16	100.24	3.85	3.48	2.0	0.743
2028	77.66	81.82	99.80	87.21	85.70	78.81	95.96	12.02	33.63	51.41	102.73	3.93	3.69	2.0	0.743
2029	79.22	83.46	101.79	88.95	87.45	80.45	97.88	12.26	34.30	52.44	104.79	4.01	3.76	2.0	0.743
2030	80.80	85.13	103.83	90.73	89.25	82.12	99.83	12.51	34.99	53.49	106.86	4.09	3.83	2.0	0.743
2031	82.42	86.84	105.91	92.55	91.04	83.77	101.83	12.77	35.69	54.56	109.01	4.17	3.91	2.0	0.743
2032	84.06	88.57	108.03	94.40	92.85	85.45	103.87	13.03	36.40	55.65	111.19	4.26	3.99	2.0	0.743
2033	85.74	90.31	110.19	96.29	94.71	87.17	105.95	13.30	37.13	56.76	113.42	4.34	4.07	2.0	0.743
2034	87.46	92.09	112.39	98.21	96.61	88.92	108.06	13.57	37.87	57.90	115.69	4.43	4.15	2.0	0.743
2035	89.21	93.93	114.64	100.18	98.54	90.69	110.22	13.84	38.63	59.05	118.00	4.52	4.23	2.0	0.743
2036	90.99	95.81	116.93	102.18	100.51	92.51	112.43	14.12	39.40	60.24	120.36	4.61	4.32	2.0	0.743
2037	92.81	97.72	119.27	104.22	102.52	94.36	114.68	14.40	40.19	61.44	122.77	4.70	4.40	2.0	0.743
2038	94.67	99.68	121.65	106.31	104.57	96.25	116.97	14.69	41.00	62.67	125.23	4.79	4.49	2.0	0.743
2039	96.56	101.67	124.09	108.43	106.66	98.17	119.31	14.98	41.82	63.92	127.73	4.89	4.58	2.0	0.743
Thereafter	+2/yr	+2/yr	+2/yr	+2/yr	+2/yr	+2/yr	+2/yr	+2/yr	+2/yr	+2/yr	+2/yr	+2/yr	+2/yr	2.0	0.743

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, 2024 to December 31, 2024, were $96.00/bbl for condensate, $43.86/bbl for other NGL (excluding condensate and pentane extracted from the gas stream), $3.04/mcf for natural gas, and $89.71/bbl for tight oil with no sales of heavy oil during 2024.

Reserves Reconciliation

Reconciliation of Gross Reserves by Product Type
Forecast Prices and Costs

	Tight Oil			Shale Gas		
Factors	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved Plus Probable Mbbl	Gross Proved MMcf	Gross Probable MMcf	Gross Proved Plus Probable MMcf
December 31, 2023	826.9	161.1	988.0	383,122.7	314,808.5	697,931.2
Extensions & Improved Recovery [2]	—	—	—	54,255.6	66,649.7	120,905.3
Technical Revisions [3]	(34.2)	(13.7)	(47.9)	11,492.7	(3,167.7)	8,325.0
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors [4]	(0.5)	0.4	(0.1)	(627.8)	(20.8)	(648.6)
Production	(101.6)	—	(101.6)	(31,937.0)	—	(31,937.0)
December 31, 2024	690.6	147.8	838.4	416,306.2	378,269.7	794,575.9

	Natural Gas Liquids [1]			Total		
Factors	Gross Proved Mbbl	Gross Probable Mbbl	Gross Proved Plus Probable Mbbl	Gross Proved Mboe	Gross Probable Mboe	Gross Proved Plus Probable Mboe
December 31, 2023	58,503.1	48,641.7	107,144.8	123,183.8	101,270.9	224,454.7
Extensions & Improved Recovery [2]	7,134.6	10,415.3	17,549.9	16,177.2	21,523.6	37,700.8
Technical Revisions [3]	(584.2)	(6,533.5)	(7,117.7)	1,297.0	(7,075.2)	(5,778.1)
Discoveries	—	—	—	—	—	—
Acquisitions	—	—	—	—	—	—
Dispositions	—	—	—	—	—	—
Economic Factors [4]	(50.0)	(11.5)	(61.5)	(155.1)	(14.6)	(169.7)
Production	(4,411.7)	—	(4,411.7)	(9,836.1)	—	(9,836.1)
December 31, 2024	60,591.8	52,512.0	113,103.8	130,666.8	115,704.8	246,371.5

Notes
(1) Figures include NGL for both conventional and unconventional reservoirs, including condensate, pentanes plus, propane, butane and ethane. Condensate is expected to be extracted in the field and sold separately from other NGL or sold with other NGL delivered to fractionation facilities. Other NGL (propane, butane and ethane) are expected to be extracted in the field by Kiwetinohk. Condensate represents 33% and pentanes plus represents 3% on a volume basis for Total Proved reserves, and 32% condensate and 3% pentanes plus on a volume basis for Total Proved Plus Probable reserves, as at December 31, 2024.
(2) Extensions and improved recovery amount includes all new wells added as a result of step-out drilling and any reserves changes directly attributable to enhanced oil recovery activities.
(3) During 2024, the Company's negative technical revisions were primarily driven by a reduction to natural gas liquids relative to 2023. This revision resulted from a correction for an anticipated increase in NGL yields (bbl/MMcf) which failed to materialize. NGL liquids were the primary reason for downward revision of 2.5% to total MBOE.
(4) Economic factors reflect the change in forecasted commodity prices year-over-year.

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved undeveloped reserves are those reserves that can be estimated with a high degree of certainty to be recoverable where significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. Probable undeveloped reserves are those additional reserves that are less certain to be recovered than proved reserves where significant expenditure is required to render them capable of production. The 2024 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, 2024, undeveloped reserves represented approximately 65% 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 2024 Reserves Report, Kiwetinohk anticipates a well development schedule in which approximately 60% of the future drilling would occur between 2025 to 2029 to develop proven reserves while probable reserves would developed during the 2030-2033 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, 2024 to December 31, 2024, January 1, 2023 to December 31, 2023 and January 1, 2022 to December 31, 2022, based on forecast prices and costs.

Proved Undeveloped Reserves								
Year	Tight Oil (2) (Mbbls)		Shale Gas (MMcf)		Natural Gas Liquids 1 (Mbbls)		Total (Mboes)	
	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-22	—	—	66,092.1	283,176.1	7,633.5	37,535.3	18,648.9	84,731.3
31-Dec-23	—	—	49,893.8	250,335.7	11,397.8	40,185.2	19,713.4	81,907.8
31-Dec-24	—	—	38,032.2	263,099.0	5,373.1	41,351.2	11,711.8	85,201.0

Probable Undeveloped Reserves								
Year	Tight Oil (2) (Mbbls)		Shale Gas (MMcf)		Natural Gas Liquids (1) (Mbbls)		Total (Mboes)	
	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-22	—	—	54,906.1	285,449.6	6,750.9	32,425.2	15,901.9	80,000.1
31-Dec-23	—	—	70,715.8	286,795.7	17,182.7	44,664.8	28,968.7	92,464.1
31-Dec-24	—	—	62,299.9	342,276.9	9,946.2	47,950.9	20,329.5	104,997.1

Proved Plus Probable Undeveloped Reserves								
Year	Tight Oil (2) (Mbbls)		Shale Gas (MMcf)		Natural Gas Liquids (1) (Mbbls)		Total (Mboes)	
	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-22	—	—	120,998.2	568,625.7	14,384.4	69,960.5	34,550.8	164,731.5
31-Dec-23	—	—	120,609.6	537,131.4	28,580.5	84,850.0	48,682.1	174,371.9
31-Dec-24	—	—	100,332.1	605,375.9	15,319.3	89,302.1	32,041.3	190,198.1

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 33% and 3% of the reflected Gross Proved and approximately 32% and 3% Gross Proved plus Probable categories, respectively, as at December 31, 2024.
(2) Tight Oil reserves are held within developed categories, with no undeveloped Tight Oil reserves.

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, 2024. 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 ($mm)	Total Proved plus Probable ($mm)
2025	282.3	282.3
2026	326.5	326.5
2027	352.4	352.4
2028	381.5	381.5
2029	394.0	394.0
Thereafter	39.2	1,211.8
Total FDC, Undiscounted	1,775.9	2,948.5
Total FDC, Discounted at 10%	1,369.2	1,987.3

Kiwetinohk expects to fund the development costs of its reserves through current working capital, cash flow from operations, borrowings under its credit facilities and by accessing the global capital markets. There can be no guarantee that funds will be available or that the Board of Directors will allocate funding to develop all of the reserves attributed in the 2024 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, 2024.

Natural Gas Wells				Oil Wells			
Producing(1)		Non-Producing(1)		Producing(1)		Non-Producing(1)	
Gross	Net	Gross	Net	Gross	Net	Gross	Net
228	217.8	124	75.7	13	9.1	53	27.8

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

Properties with No Attributed Reserves

The following table sets forth the Company's properties with no reserves assigned as at December 31, 2024:

Unproved (Acres)	Gross	Net
Alberta		
Duvernay	27,357	27,357
Montney	76,320	68,450
Other Fox Creek formations	44,800	34,842
Misc. AB	26,112	9,574
British Columbia	8,751	3,237
Total	183,340	143,460

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 by counting overlapping acreage in certain key formations under applicable petroleum and natural gas agreements twice.

For the year ending December 31, 2025, approximately 3,280 net acres of the Company will come up for expiry. Kiwetinohk believes that, subject to Crown approval approximately 20% 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 $247.6 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.

Tax Horizon

Based on estimated taxable income outlined within the 2024 Reserves Report which estimates future cash flow from operating activities, capital expenditures and existing tax pools, the Company expects to be taxable starting in mid to late 2026. This estimate of future taxability is based on total proved and probable reserves and the three consultant average forecast prices outlined above.

Costs Incurred

The following table summarizes the costs incurred by Kiwetinohk for the 12 months ended December 31, 2024.

	12 months ended December 31, 2024 *($MM)*
Property acquisition costs:	
Proved properties	(0.3)
Unproved properties	—
Exploration costs	—
Development costs	327.9
Other [1]	3.3
Total:	330.9

1 Other balance is comprised of capitalized G&A related to upstream capital.

Exploration and Development Activities

The following table sets out the gross and net exploratory and development wells brought on production in which Kiwetinohk participated in the 12 months ended December 31, 2024.

	Development		**Exploratory**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Natural Gas	16	16	—	—	16	16
Oil	—	—	—	—	—	—
Service	—	—	—	—	—	—
Stratigraphic Test	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total:	16	16	—	—	16	16

In 2025, 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, 2025 in the estimates contained in the 2024 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[1] Estimate for the Twelve-Month Period Ending December 31, 2025.

Reserve Category	Shale Gas *(mmcf)*	NGL *(mbbl)*	Tight Oil *(mbbl)*	Total *(mboe)*
Proved	35,500	5,200	78	11,195
Probable	2,300	364	2	749
Total Proved plus Probable	37,800	5,564	80	11,944

Notes:

(1) Working interest before the deduction of royalties.

(2) NGL refers to condensate plus NGL volumes.

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, 2024	June 30, 2024	September 30, 2024	December 31, 2024
Average Gross Daily Production[1][5]				
Shale Gas (mmcf/d)	90.5	89.3	80.0	89.4
Natural Gas Liquids (bbl/d)	4,027.1	3,817.0	3,766.3	4,132.5
Condensate[2]	8,008.3	7,282.5	8,611.9	8,363.0
Tight Oil (bbl/d)[3]	443.9	315.1	285.4	264.3
Combined (boe/d) [6]	27,555.7	26,291.2	25,995.6	27,657.2
Average Production Prices Received				
Shale Gas ($/mcf)	$3.83	$2.39	$2.49	$3.40
Natural Gas Liquids ($/bbl)	$46.65	$42.21	$41.36	$44.97
Condensate ($/bbl) [2]	$93.28	$102.77	$93.33	$95.51
Tight Oil ($/bbl)[3]	$75.34	$101.21	$97.67	$91.40
Combined ($/boe)	$47.72	$43.91	$45.65	$47.44
Royalties Paid [8]				
Shale Gas ($/mcf)	$(0.04)	$—	$0.08	$0.02
Natural Gas Liquids ($/bbl)	$(3.91)	$(6.61)	$(4.80)	$(4.55)
Condensate ($/bbl) [2]	$(9.92)	$(10.29)	$(8.48)	$(7.72)
Tight Oil ($/bbl)[3]	$(2.10)	$(13.59)	$(15.68)	$(16.53)
Combined ($/boe)	$(3.62)	$(3.96)	$(3.44)	$(3.11)
Production Costs[3]				
Shale Gas ($/mcf)	$(1.17)	$(1.03)	$(1.20)	$(1.29)
Natural Gas Liquids ($/bbl)	$(7.03)	$(6.17)	$(7.19)	$(7.73)
Condensate ($/bbl) [2]	$(7.03)	$(6.17)	$(7.19)	$(7.73)
Tight Oil ($/bbl)[3]	$(7.03)	$(6.17)	$(7.19)	$(7.73)
Combined ($/boe)	$(7.03)	$(6.17)	$(7.19)	$(7.73)

	Quarter Ended			
	March 31, 2024	June 30, 2024	September 30, 2024	December 31, 2024
Transportation Costs				
Shale Gas ($/mcf)	$(1.20)	$(1.22)	$(1.27)	$(1.20)
Natural Gas Liquids ($/bbl) (7)	$(1.43)	$(4.19)	$(4.34)	$(2.90)
Condensate ($/bbl) (2) (7)	$(1.43)	$(4.19)	$(4.34)	$(2.90)
Tight Oil ($/bbl)(7)	$(1.43)	$(4.19)	$(4.34)	$(2.90)
Combined ($/boe)	$(4.60)	$(5.96)	$(6.03)	$(5.22)
Netback Received(4)(6)				
Shale Gas ($/mcf)	$1.42	$0.14	$0.10	$0.93
Natural Gas Liquids ($/bbl)	$34.28	$25.24	$25.03	$29.79
Condensate ($/bbl) (2)	$74.90	$82.12	$73.32	$77.16
Tight Oil ($/bbl)	$64.78	$77.26	$70.46	$64.24
Combined ($/boe)	$32.47	$27.82	$28.99	$31.38

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 disposition of west simonette and other Alberta properties. Production data includes consolidated data up until disposition date.
(6) Due to rounding, certain rows may not add exactly.
(7) Transportation costs for NGLs and tight oil have been allocated on a pro-rata basis.
(8) 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, 2024.

	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)	87	3,934	8,069	325	—	22,238
Placid	21	797	1,610	33	—	7,045
Simonette	66	3,137	6,459	292	—	15,193
Other Misc.	—	2	—	2	—	349
TOTAL(1)	87	3,936	8,069	327	—	22,587

Note:
(1) Numbers may not add due to rounding.

DIVIDENDS AND DIVIDEND POLICY

Kiwetinohk has not historically paid any dividends on the Common Shares and no dividends are currently contemplated in the immediate future. At the discretion of the Board, Kiwetinohk may pay dividends on the Common Shares at some time in the 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 30% 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 1.5 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); (c) at least 20% of forecasted daily production is hedged for a period of twelve months; and (d) 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, 2024, there were 43,781,748 Common Shares and no Preferred Shares issued and outstanding.

Share Buybacks

Kiwetinohk adopted a normal course issuer bid (NCIB) on December 22, 2022. During the year ended December 31, 2023, the Company purchased 598,776 Common Shares under the NCIB program at a total cost of $7.6 million (an average of $12.71 per share).

On December 22, 2023 the NCIB was renewed. During the year ended December 31, 2024, the Company did not purchase any Common Shares under the NCIB program.

On December 23, 2024 the NCIB was further renewed and Kiwetinohk is currently permitted to purchase up to 2,188,237 common shares under the NCIB, representing 5% of the 43,764,748 issued and outstanding common shares as of December 11, 2024.

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 $400.0 million which is comprised of an operating facility of $65.0 million and a syndicated facility of $335.0 million. The Credit Facility is a 364-day committed facility available on a revolving basis until May 31, 2025, 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, 2026. 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 ratio of net debt to adjusted funds flow from operations ratio of no more than 1.0 times. Net debt to adjusted funds flow from operations is a non-GAAP measure that may not be comparable to other entities. See "*Non-GAAP and other financial measures*" for further information.

Letter of Credit Facility

On May 27, 2024, Kiwetinohk amended and increased the unsecured demand revolving letter of credit facility (the "**LC Facility**") with Export Development Canada (**"EDC"**) from $75.0 million to $125.0 million. Kiwetinohk's obligations under the LC Facility are supported by a performance security guarantee ("**PSG**") granted by EDC to the Credit Facility lender to guarantee the payment of certain amounts in respect of LCs. The PSG is valid to May 31, 2025 and may be extended from time-to-time at the option of Kiwetinohk and with the agreement of EDC. The Company expects to renew the PSG in May 2025 concurrently with its annual borrowing base review of the consolidated Credit Facility.

Other securities

The Company has 2,826,802 options ($10.92 weighted average exercise price and 2.4 years average life remaining) and 6,583,395 Performance Warrants ($20.00 weighted average exercise price and 1.5 years average life remaining) outstanding at December 31, 2024.

The Company has cash-settled securities outstanding related to DSUs, RSUs, and 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, 2024 the Company had 145,378 DSUs outstanding, 342,578 PSUs outstanding and 461,864 RSUs outstanding.

Additional details are included in the December 31, 2024 annual consolidated financial statements and will also be included in the Compensation Discussion and Analysis section of the Company's Management Information Circular to be filed in [April] 2025, 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.sedarplus.ca.

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 total monthly trading volumes of its Common Shares as reported by the TSX for the periods indicated:

	Common Share Price			
	High	Low	Close	Volume
2024				
January	$11.52	$10.81	$11.30	114,316
February	$11.20	$10.85	$10.85	65,340
March	$11.85	$10.65	$11.85	434,701
April	$12.96	$12.21	$12.54	65,585
May	$13.17	$12.30	$13.17	141,853
June	$13.48	$12.51	$13.19	103,960
July	$13.70	$13.21	$13.60	81,130
August	$14.73	$12.76	$14.60	90,023
September	$14.33	$13.60	$13.98	141,129
October	$15.25	$14.10	$15.00	402,902
November	$15.51	$15.05	$15.51	81,555
December	$16.35	$15.54	$16.35	113,021

	Common Share Price			Volume
	High	Low	Close	
2025				
January	$17.48	$16.70	$17.20	105,830
February	$17.30	$16.35	$16.60	98,518
March 1-4	$16.00	$15.09	$15.09	4,998

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, 2024 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 5, 2024	2,500	RSU	$10.87
March 5, 2024	5,000	PSU	$10.87
March 31, 2024	14,717	DSU	$11.18
June 30, 2024	12,826	DSU	$12.83
August 2, 2024	202,189	Stock Options	$13.54
August 2, 2024	272,998	RSU	$12.92
August 2, 2024	204,038	PSU	$12.92
September 30, 2024	12,037	DSU	$13.67
November 8, 2024	1,698	Stock Options	$15.17
November 8, 2024	4,078	RSU	$15.10
December 31, 2024	10,269	DSU	$16.03

ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

As of December 31, 2024 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	62.9%
Luminus[(2)]	5,202,334	11.9%

Notes:
(1) Such Common Shares are owned both of record and beneficially by ARC.
(2) Such Common Shares are owned both of record and beneficially by Luminus.
(3) This information has been obtained by the Company from filings on the System for Electronic Disclosure by Insiders at www.sedi.ca and through information provided by ARC 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 a total of nine directors elected to the Board, ARC will have the right to designate: (a) one director nominee for so long as ARC exercises control or direction over 10% or more of the Common Shares; (b) two director nominees for so long as ARC exercises control or direction over 25% or more of the Common Shares; and (c) three director nominees 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. As long as ARC is entitled to have a nominee on the Board, Kiwetinohk shall ensure that the nominee of ARC is either appointed to or granted observer rights on each committee of directors formed by the Board. ARC is currently entitled to three director nominees for election to the Board; as of the date of this AIF, ARC has three director nominees on the Board.

While 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 (an "**ARC Demand Registration**"). Provided 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), 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.

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**"). Subject to certain conditions and limitations, Kiwetinohk must cause to be included in the ARC Piggyback Registration all Common Shares that ARC requests to be included.

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.

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 so long as Luminus exercises control or direction over 10% or more of the Common Shares. As long as Luminus is entitled to have a nominee on the Board, Kiwetinohk shall 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 observer 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 (a "**Luminus Demand Registration**"). Provided 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), 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.

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**"). Subject to certain conditions and limitations, Kiwetinohk must cause to be included in the Luminus Piggyback Registration all Common Shares that Luminus requests to be included.

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.

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

DIRECTORS AND OFFICERS

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

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since	Number and Percentage of Common Shares Held
Kevin Brown Calgary, AB Canada	Director (Chair) • *Audit Committee Member* • *Governance and Nominating Committee Member*	Kevin Brown is the Co-Chairman and Director of ARC Financial Corp. He has been with ARC Financial Corp. since 1989.	December 2018	--[1][2]
Beth Reimer-Heck Calgary, AB Canada	Director (Lead) • *Audit Committee Member* • *Health, Safety and Environment Committee Member (Chair)* • *Governance and Nominating Committee Member*	Beth Reimer-Heck is a corporate director and former senior counsel at the law firm of Borden Ladner Gervais LLP. She is also an advisory board member of Saskatchewan Mines and Minerals Inc., advisory board member of the Calgary Chapter of the Institute of Corporate Directors, and a director of the United Way of Calgary and Area.	September 2021	9,100 (0.02%)
Judith Athaide Calgary, AB Canada	Director • *Health, Safety and Environment Committee Member* • *Governance and Nominating Committee Member (Chair)*	Judith Athaide is a Corporate Director and has previously served on the Boards of Canada Pension Plan Investments Board, Computer Modelling Group Ltd, HSBC Bank Canada and Sustainable Development Technology Canada. She is also a Corporate Director and the President and CEO of The Cogent Group Inc., a private strategic advisory firm and serves on the Board of Canada Pension Plant Investments Board.	February 2022	9,020 (0.02%)
Colin Bergman Calgary, AB Canada	Director • *Reserves Committee Member* • *Health, Safety and Environment Committee Member*	Colin Bergman is a Senior Vice-President at ARC Financial Corp. and is a CFA Charterholder. Prior to joining ARC, Colin was an investment banking professional at BMO Capital Markets	May 2023	--[1][2]
Patrick Carlson Calgary, AB Canada	Chief Executive Officer and Director • *Reserves Committee Member* • *Health, Safety and Environment 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	1,021,335[3] (2.33%)
Leland Corbett Calgary, AB Canada	Director • *Compensation Committee Member (Chair)* • *Health, Safety and Environment Committee Member* • *Governance and Nominating Committee Member*	Leland Corbett is a partner at Stikeman Elliott LLP. He has been at Stikeman Elliott LLP since 1994.	August 2018	30,838 (0.07%)

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since	Number and Percentage of Common Shares Held
Alicia Kilmer Calgary, AB Canada	Director • *Reserves Committee Member*	Ms. Kilmer is Vice-President of Strategy & Business Development at Tundra Oil & Gas and founder of AMK Strategy Consulting. Previously, she managed Strategic Planning and New Ventures at ARC Resources Ltd., with a focus on reserves, strategy and capital allocation.	January 2025	--
Kaush Rakhit Calgary, AB Canada	Director • *Reserves Committee Member (Chair)* • *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 (0.23%)
Steve Sinclair Calgary, AB Canada	Director • *Audit Committee Member* • *Compensation Committee Member* • *Reserves 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	20,000 (0.05%)
John Whelen Calgary, AB Canada	Director • *Audit Committee Member (Chair)* • *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 (0.09%)
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	21,985 (0.05%)
Mike Backus Calgary, AB Canada	Chief Operating Officer, Upstream	Mike Backus was appointed as Chief Operating Officer of the Company effective October 25, 2021, and brings over 25 years of industry experience in engineering and operational finance to Kiwetinohk, both domestically and internationally. Prior to this role, Mr. Backus held executive roles at Painted Pony Energy, CNOOC International, and its predecessor, Nexen Inc.	N/A	29,292 (0.07%)
Jakub Brogowski Calgary, AB 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	23,415[4] (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	55,083[6] (0.13%)
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%)
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.	N/A	--

Name, Province and Country of Residence	Position Held	Principal Occupation for the Last Five Years	Director Since	Number and Percentage of Common Shares Held
Fareen Sunderji Calgary, AB Canada	President, Power Division	Fareen Sunderji was appointed President, Power Division in August, 2023. Prior to joining Kiwetinohk, she held progressive leadership roles in engineering, operations, supply chain, projects and commercial operations at TC Energy.	N/A	7,905 (0.02%)
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	105,424 (0.24%)

Notes:
(1) Mr. Brown and Mr. Bergman 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 and Mr. Bergman do not own any Common Shares. Shares previously registered in Mr. Brown's or Mr. Bergman'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 521,135,Common Shares.
(4) Jakub Brogowski's wife, Claudia Huynh, holds 13,906 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 24,500 Common Shares in her name. Mike Hantzsch holds the other 30,583 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, 2024, the current directors and officers of the Company, as a group, beneficially owned, controlled or directed, directly or indirectly, 1,569,610 Common Shares, representing approximately 3.6% 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:

(1) 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

(2) 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:

(1) 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

(2) 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:

(1) 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

(2) 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 on the Company's profile at the website maintained by the Canadian Securities Administrators at www.sedarplus.ca.

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 "B".

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.

	2024 *($)*	2023 *($)*
Audit Fees(1)	336,750	260,000
Audit-Related Fees(2)	25,000	60,000
All Other Fees(3)	94,500	120,500
Tax Fees(4)	—	—
Total	**456,250**	**440,500**

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 due diligence related to acquisitions, base shelf prospectus, aggregate fees billed for permissible services related to limited assurance procedures on scope 1 and scope 2 greenhouse gas emissions, stand alone audits of certain partnerships and other.
(4) Kiwetinohk did not incur any fees related to tax compliance, tax advice or tax planning services from Deloitte LLP, as external auditor, during 2024 or 2023.

LEGAL PROCEEDINGS AND REGULATORY ACTIONS

The Company is involved in litigation and disputes arising in the normal course of operations. Management is of the opinion that any potential litigation will not have a material adverse impact on the Company's financial position or results of operations and 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:

(1) the Credit Agreement;
(2) the Investment Rights Agreement (ARC); and
(3) 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.sedarplus.ca.

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.

The auditors, Deloitte LLP are independent of the Company within the meaning of the rules of professional conduct of the Chartered Professional Accountants of Alberta.

NON-GAAP AND OTHER FINANCIAL MEASURES

Throughout this AIF and in other materials disclosed by the Company, the Company uses various specified financial measures including “non-GAAP financial measures”, “non-GAAP financial ratios”, "supplementary financial measures" and “capital management measures”, as defined in National Instrument 52-112 Non-GAAP and Other Financial Measures Disclosure and explained further in the Company's MD&A. The disclosure under the section entitled "Other - Non-GAAP and Other Financial Measures" contained in Kiwetinohk's MD&A is incorporated by reference into this document.

Non-GAAP Financial Measures

Throughout this AIF, the Company uses various "non-GAAP financial measures" as defined in National Instrument 52-112 Non-GAAP and Other Financial Measures Disclosure, including "capital expenditures" and "operating netback". The most directly comparable GAAP measure to capital expenditures is "cash flow used in investing activities". The most directly comparable GAAP measure to operating netback is "commodity sales from production".

The Non-GAAP Measures presented in this AIF should not be considered in isolation or as a substitute for performance measures prepared in accordance with IFRS and should be read in conjunction with the Company's audited consolidated financial statements and MD&A. Readers are cautioned that these measures do not have standardized meanings and should not be used to make comparisons between Kiwetinohk and other companies. See the heading "Non-GAAP and other financial measures" in the Company’s MD&A, available on SEDAR+ at www.sedarplus.ca and incorporated by reference into this AIF, for a detailed analysis, calculation and reconciliation of these measures.

Supplementary Financial Measures

The presentation contains a number of supplementary financial measures, including net present value, or NPV, which does not have a standardized meaning or a standard method of calculation and therefore may not be comparable to similar measures used by other companies. This metric has been included to provide readers with an additional measure to evaluate the Company and future performance, however, this measure is not a reliable indicator of the future performance of the Company and future performance may not compare to performance in previous periods. Therefore, this metric should not be unduly relied upon. NPV10 is the difference between the present value of cash inflow and the present value of cash outflow over a period of time at a 10% discount rate. Management uses this financial metric for its own performance measurements, and to provide investors with a measure to compare the Company's economic returns and operations over time. Readers are cautioned that the information provided by this metric or that can be derived from this metric, as presented herein, should not be relied upon for investment or other purposes.

Additional information relating to non-GAAP measures utilized by the Company, including how the Company utilizes these measures can be found within the the Company's MD&A available under the Company's profile on the website maintained by the Canadian Securities Administrators on the Company's profile at www.sedarplus.ca or at www.kiwetinohk.com.

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, 2024 and 2023, are available under the Company's profile on the website maintained by the Canadian Securities Administrators on the Company's profile at www.sedarplus.ca.

APPENDICIES

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:

"**2024 Reserves Report**" means the independent reserves report prepared by McDaniel dated March 04, 2025 evaluating the reserves attributable to certain of the assets of Kiwetinohk and its subsidiaries as at December 31, 2024.

"**ABCA**" means the *Business Corporations Act* (Alberta), RSA 2000, c B-9, as amended, including the regulations thereunder.

"**AECO**" means the AECO C spot price, the Alberta natural gas trading price.

"**AEPA**" means the Alberta Environment and Protected Areas.

"**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 Emissions Grid Displacement Factor**" means the amount of greenhouse gas emissions per megawatt-hour (MWh) of electricity generated. The emissions grid displacement factor is used to calculate emission offsets for renewable energy projects.

"**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 Kiwetinohk's 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.

"**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.

"**CBCA**" means the Canada Business Corporations Act, R.S.C. 1985, c. C-44, as amended, including the regulations promulgated thereunder.

"**CCS**" means carbon capture and storage.

"**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.

"**CERegs**" means the Clean Electricity Regulations.

"**CETA**" means the Comprehensive Economic and Trade Agreement.

"**Chair**" and "**Chairperson**" means the chairperson of the Board of Directors.

"**CO_2**" means carbon dioxide.

"**CO_2E**" means **CO_2** equivalent.

"**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 May 27, 2024 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.

"**CUKTCA**" means the Canada-United Kingdom Trade Continuity Agreement.

"**Directive 67**" has the meaning ascribed thereto under the heading "*Risk Factors – Risks related to the Company – Security Deposits under Provincial Liability Management Programs*".

"**Directive 68**" has the meaning ascribed thereto under the heading "*Risk Factors – Risks related to the Company – Security Deposits under Provincial Liability Management Programs*".

"**Directive 88**" has the meaning ascribed thereto under the heading "*Licensee Life-Cycle Management in 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.

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

"**EDC**" has the meaning ascribed thereto under the heading "*Letter of Credit Facility*".

"**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.sedarplus.ca.

"**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.

"**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.

"**IAAC**" means the Impact Assessment Agency of Canada.

"**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.

"**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*".

"**IRP**" means the Inventory Reduction Program.

"**Kiwetinohk**", "KEC" or "**Company**" means Kiwetinohk Energy Corp., a corporation existing under the federal laws of Canada.

"**LCA**" means the Licensee Capability Assessment System.

"**LC Facility**" has the meaning ascribed thereto under the heading "*Letter of Credit Facility*".

"**Licensee Life-Cycle Management**" has the meaning ascribed thereto under the heading "*Legal and Regulatory Regime – Upstream Oil and Natural Gas Industry – Licensee Life-Cycle Management in Alberta*".

"**LLCM Directive**" means the AER's Directive 088: Licensee Life Cycle Management Directive, effective as of February 7, 2025.

"**LUF**" means the Alberta Land Use Framework.

"**Luminus**" means Luminus Energy IE Designated Activity Company.

"**Luminus Demand Registration**" has the meaning ascribed thereto under the heading "*Principal Holders of Voting Securities – Investment Rights Agreement (Luminus)*".

"**Luminus Piggyback Registration**" has the meaning ascribed thereto under the heading "*Principal Holders of Voting Securities – Investment Rights Agreement (Luminus)*".

"**Market Price**" means, in respect of Options only, the volume weighted average trading price of the Common Shares on the TSX, or such other exchange on which the Common Shares are listed and posted for trading and on which the majority of the trading volume and value of the Common Shares occurs, for the five trading days immediately preceding the day on which the Option is granted. In the event that the Common Shares are not traded on an exchange, then the Market Price shall be the fair market value of the Common Shares as determined by the Board in its sole discretion, acting reasonably and in good faith.

"**McDaniel**" means McDaniel & Associates Consultants Ltd, independent reserves evaluators.

"**MSA**" means Market Surveillance Administrator.

"**NAFTA**" means the North American Free Trade Agreement.

"**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.

"**NGCC**" means natural gas combined cycle.

"**NGTL**" has the meaning ascribed thereto under the heading "*Description of Kiwetinohk's Business – Overview of Oil and Natural Gas Properties – Midstream, Marketing and Transportation Arrangements – TC Energy*".

"**NGX**" means the Natural Gas Exchange.

"**NIT**" means the Nova Inventory Transfer.

"**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.

"**OGMP 2.0**" means Oil and Gas Methane Partnership 2.0.

"**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.

"**Order**" has the meaning ascribed thereto under the heading "*Directors and Officers – Cease Trade Orders, Bankruptcies, Penalties or Sanctions – Cease Trade Orders and Bankruptcies*".

"**Pembina**" means Pembina Pipeline Corporation.

"**Pembina Peace Pipeline**" has the meaning ascribed thereto under the heading "*Description of Kiwetinohk's 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.

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

"**PSG**" has the meaning ascribed thereto under the heading "*Letter of Credit Facility*".

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

"**Reserves Committee**" means the reserves committee of the Board.

"**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.**

"**Sustainability Committee**" means the sustainability committee of the Board.

"**TSX**" means the Toronto Stock Exchange.

"**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.

"UNEP" means United Nations Environment Programme.

"**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.

"**USMCA**" means the United States Mexico Canada Agreement.

"**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:

(1) 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;

(2) 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;

(3) 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

(4) 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:

(1) 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;

(2) 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;

(3) dry hole contributions and bottom hole contributions;

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

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

"**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:

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

(2) 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:

(1) 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;

(2) in relation to wells, the total number of wells in which a company has an interest; and

(3) 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:

(1) 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;

(2) 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

(3) 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
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
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British thermal units
mmcf	million cubic feet
mmcf/d	million cubic feet per day
C2+	ethane plus
C3+	propane plus
C5+	pentanes plus/condensate

Other	
API	American Petroleum Institute
GW	gigawatts
m	meters
MW	megawatts
MWh	megawatt hour
km	kilometers
$mm	million dollars
$/bbl	dollars per barrel
$/boe	dollars per barrel equivalent
$/mcf	dollars per thousand cubic feet

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) 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) 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) Principles and Rules

3.1 Composition and Meetings

1. 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.

2. 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.

3. 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:

(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.

(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:

1. 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*;
2. compliance with covenants under credit facility loan agreements;
3. any examinations or reports by regulatory agencies;
4. any external independent auditor observations; and
5. regular updates from management and legal counsel regarding compliance matters.

(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.

(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

(a) 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.

(b) 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 Independent Qualified Reserves Evaluator or Auditor

Please see attached.

FORM 51-101F2
REPORT ON RESERVES DATA
BY
INDEPENDENT QUALIFIED RESERVES EVALUATOR OR AUDITOR

To the board of directors of Kiwetinohk Energy Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at December 31, 2024. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2024, estimated using forecast prices and costs.

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

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

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

5. The following table shows the net present value of future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated for the year ended December 31, 2024 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	Dec. 31, 2024	Canada	—	2,860,711.1	—	2,860,711.1

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

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

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

Executed as to our report referred to above:

McDaniel & Associates Consultants Ltd., Calgary, Alberta, Canada, March 4, 2025

(Originally signed by) "Brian Hamm"

Brian Hamm, P.Eng.
President & CEO

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, 2024.

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) "Mike Backus"
Mike Backus
Chief Operating Officer

(signed) "Kaush Rakhit"
Kaush Rakhit
Director

(signed) "Steve Sinclair"
Steve Sinclair
Director

March 4, 2025