2024-05-27

Dear Shareholders;

Message from the CEO

It has been more than two years since, Kiwetinohk Energy Corp. ("Kiwetinohk", "KEC" or the "Company") listed on the Toronto Stock Exchange with a ten-year energy transition strategy articulated in some detail. The strategy was a response to a business opportunity that Kiwetinohk predicted would result from changes to government policy and consumer attitude in response to climate change. Our purpose has since been stated in words like these:

Our purpose is to build a company that profitably provides customers with clean, reliable, dispatchable, and affordable energy.

Before listing, the Company operated as a private company for approximately four years with a similar purpose.

I want to take this opportunity to describe some core elements of our strategy designed to differentiate by and within our scope of business. These are presented in considerable detail, each in a separate appendix (A through D) hereto, so the subject and theme of each are summarized below:

A. Components of Kiwetinohk's full energy transition business,

- In Appendix A, I describe the components of Kiwetinohk's energy transition business. Kiwetinohk set out to build an enterprise that could capture and convert Alberta's abundant hydrocarbon and renewable primary energy resources to clean energy in the forms of electricity and hydrogen. To date, electricity generation has been prioritized because infrastructure with available capacity was available as Alberta decommissioned its coal-fired power generation fleet. My observation, provided to you without verification, is that society has been presented with many, un-proven, high-risk technology solutions for the required energy transition. Energy is too important to our lives and our economy to set out on a policy-driven course that makes society reliant on the successful development and commercialization of technologies that do not yet exist. What is really needed is a transition that is reliant on proven technology. Investment in innovation also has a place but the commercial need, right now, is for deployment of the cleanest, most economical, **proven** means of meeting society's energy needs. We, at Kiwetinohk, believe that, now and in the short term, we are proposing a balanced portfolio of generation components that Alberta's power grid needs. These projects allow the Alberta power market to take a meaningful, technically proven, step in the direction of clean, reliable, dispatchable, and affordable energy. This first step remains compatible with our 10-year goals as disclosed when we listed.

B. Capturing and financing the energy transition investment opportunity,

- In Appendix B, I describe financing options Kiwetinohk plans to explore as it searches for financing for its power and carbon capture and storage ("CCS") plants. Kiwetinohk's seven grid-scale power projects and its two associated carbon capture projects are likely to be strongly affected by policies presently in development by the governments of Canada and Alberta. KEC believes that the projects have both low technology risk and low emissions intensity, characteristics that the Alberta power market needs. Since the projects are what Alberta needs, evolving government policy should favor their construction and bolster their ability to attract project financing. Right now, however, KEC is spending cautiously to keep each project ready to re-assess, finance and advance as soon as alignment of KEC's strategy with new government policies is confirmed.

Appendix B also addresses KEC's financing strategy for the power and carbon capture divisions. Capital markets may be telling KEC that financing the upstream business separate from the power and CCS businesses may enhance the Company's access to equity capital.

C. Securing and maintaining social license to operate, and
- In Appendix C, I describe the main activities KEC has undertaken to engage Indigenous people in our business and how that fits into our overall strategy to earn and maintain a social license to operate.

D. Gaining incremental value through well design modification.
- In Appendix D, I describe some of the tests KEC is doing to reduce risks and add value while adding new wells to our upstream operation. KEC experiments with well design and operating procedures with the goal of reducing environmental impacts and improving operating safety and resource recovery economics. The Company is very pleased with drilling, completion, and production results of its new well program. These results encourage KEC to continue testing ways to increase the profitability of its upstream operations. Further, our success with longer wells suggests we can reduce surface disturbance. With initial results looking encouraging, we plan to continue pursuing incremental improvements.

I am passionate about Kiwetinohk's business and what our team of employees and contractors are achieving. Thank you for letting me describe these elements to you.

Wishing you health, safety, and happiness,

Sincerely,

(signed) "Pat Carlson"
CEO, Kiwetinohk Energy Corp.

Appendix A: Components of Kiwetinohk's full energy transition business

Over the nearly six years of KEC's existence, climate change, specifically its widely accepted anthropogenic causes including methane and carbon dioxide emissions, has been foremost on the minds of many energy specialists in science, policy, and business. Despite the widely accepted need for investment in technologies that can reduce greenhouse gas emissions intensity, KEC knows of, no other company in Canada that has attempted to build a business that spans the full spectrum of the clean energy[1] transition challenge. That spectrum includes capturing raw energy and processing it to make, with materially reduced greenhouse gas emissions, clean forms that consumers can use. Electricity is the only form of clean energy available to most consumers. Hydrogen, another form of clean energy, has advantages over electricity in some situations. Examples of hydrogen's advantage include: 1) it often is preferred to battery-stored electricity as a long-haul transportation energy source and 2) the marketing and distribution of hydrogen favors the private sector competing to build new systems suited to the energy transition. By comparison, electricity grids are often government-controlled monopolies built over a century to meet the needs of the past. Advantages such as these, open the door for hydrogen to gain a larger share of the clean energy market in the long term.

Kiwetinohk is planning to build six component businesses that, together, can contribute to Alberta meeting the energy transition challenge of providing clean, reliable, dispatchable, and affordable energy to markets. These component businesses are listed in Table 1.

KEC attaches some important competitive strategies to its plan to contribute profitably to Alberta's energy transition:

1. ***Assure nimbleness by advancing three types of power generation to Final Investment Decision ("FID"):***
    1) ***solar,***
    2) ***natural gas-fired peaker, and***
    3) ***natural gas combined cycle (co-located with CCS plants.)***

   Proceed with FID and construction of the plants that the market most rewards. At this stage of its evaluation, KEC believes that these businesses are all needed for continued robust growth of the Alberta economy while reducing greenhouse gas emissions. By intent, KEC's plan can be adjusted toward optimally balancing the reliability and dispatchability of natural gas-fired plants with the cleanliness and low operating cost of solar and wind power. For Alberta, aside from reducing greenhouse gas emissions, deploying renewable power extends low-cost gas reserves and delays filling of sequestration space. On the other hand, the instability of renewable power can be somewhat mitigated by gas-fired power, especially peaker plants. If current technology continues to prevail, KEC expects that renewable energy will achieve its maximum proportionate contribution to the power grid only with stability-enhancing peakers. The net annual average expected delivery to the grid of KECs seven advancing power plants totals

[1] In this letter, the term, "clean energy", means energy with the lowest greenhouse gas emissions intensity (from resource to end use) that Kiwetinohk believes is, or can be made commercially available to consumers. This includes attracting debt and equity investment capital for deployment of commercially proven technology in the current economic environment.

approximately 1.1 GW representing about 10% of the Alberta grid's current internal peak load.

2. ***Select from proven technologies to reduce risk and apply specific technology to improve operating netbacks.*** On one hand, KEC expects each of its core businesses to be profitable with proven technologies. On the other hand, technology is part KEC's culture. Specifically, for the power generation plants, KEC seeks to beat its competition in the hourly bidding for capacity in the Alberta power market. KEC expects to be able to underbid competitors by selecting technologies that will enable each KEC plant to operate at a lower cost than most of the plants of the same class currently in the Alberta fleet. KEC plans to achieve low costs by selecting technologies with high efficiency. Higher efficiency generally leads to lower natural gas consumption which, in turn, leads to lower carbon dioxide production. Both natural gas fuel purchase and carbon dioxide emission abatement contribute to the marginal operating cost of power generation. Having high efficiency plants is expected to enable KEC to achieve higher netbacks than most plants in the current Alberta, grid-connected fleet. This applies to each of two classes of plants: first, gas-fired baseload including NGCC plants and second, simple cycle including peaker plants. Note that this element of KEC's strategy is generally compatible with and somewhat dependant on government policies that encourage the minimization of carbon dioxide emissions intensity. Please note that this application of technology to improve competitiveness is also deployed in our upstream natural gas production operations. KEC seeks to reduce costs which increases netbacks by continually adjusting well design to suit the Company's regionally varying resource better.

3. ***Vertically integrate the business to provide any part of the energy transition that the market needs but locate separate components to maximize value.*** In a perfect world, KEC could build its vertically integrated business as integrated plants on top of gas fields. That could minimize capital expenditures for interconnecting utilities such as captured carbon dioxide and natural gas pipelines, power lines, and water lines. Also, natural gas and power could be distributed in behind-the-fence mode avoiding some fees that generally apply to a utility-connected enterprise. Figure 1 shows how the components of KEC's business could, with maximized synergy, co-locate and share utilities to minimize cost and maximize value in that perfect world. The world is not perfect. The full package of synergistically located resources needed for large-scale plant integration as illustrated in Figure 1 is generally not available. Most often, the component plants of the overall transition strategy must be somewhat dispersed. The unusual concept here is:
    - the market needs all the components of a vertically integrated energy transition business,
    - the best place to locate any component depends on the location of the interconnections that component needs,
    - sometimes the best interconnection location for a component is remote from other KEC-planned components, and
    - the best way to provide the integration that the Alberta energy business needs to transition is to look at the whole industry, not just Kiwetinohk's business, as needing the components that KEC proposes to build.

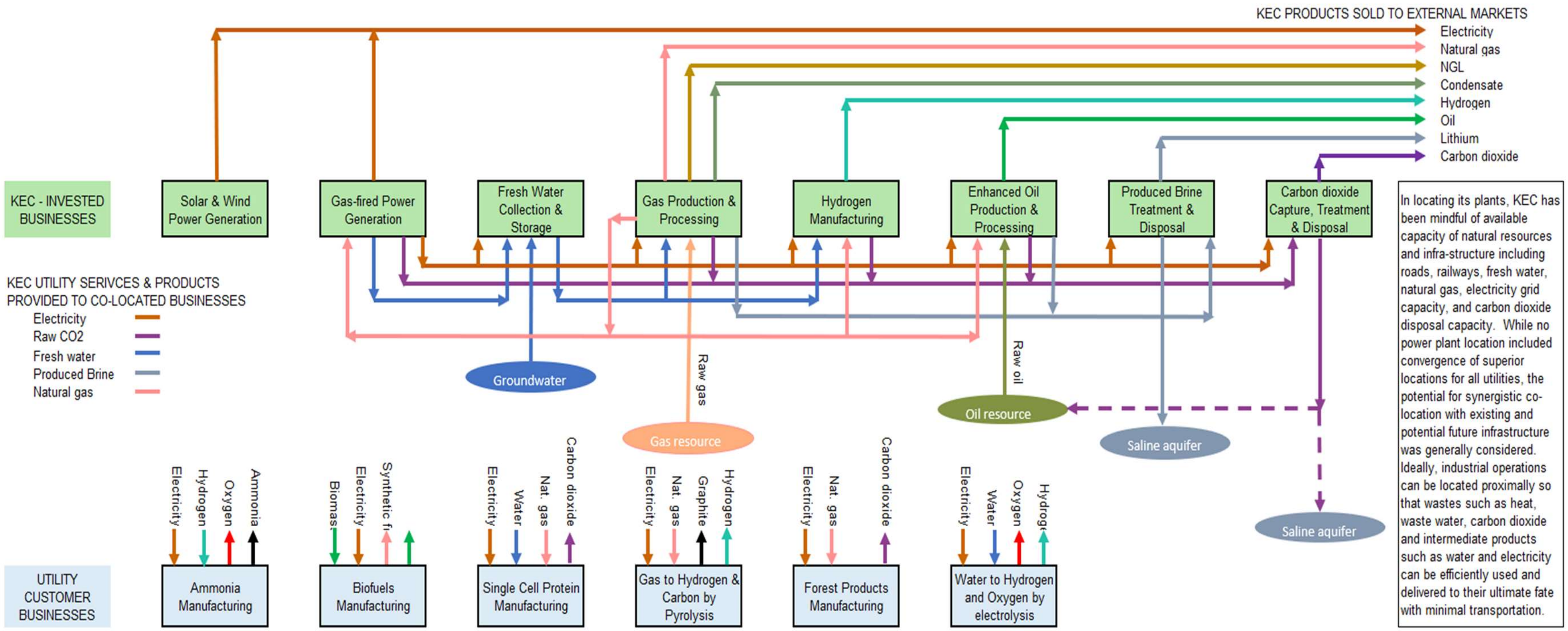

FIGURE 1 LOCATING FACILITIES TO CAPTURE PRESENT AND POTENTIAL FUTURE CIRCULAR ECONOMY SYNERGIES WITH OTHER INDUSTRIAL OPERATIONS

4. ***Build a project development company that profitably provides customers with clean, reliable, dispatchable, and affordable energy and finance that company by selling all or part of its projects to raise the required capital investment funds for the portion of the business that is retained.*** The need to build components of a vertically integrated plan in dispersed locations where they can earn the best return is compatible with project financing. In this financing structure, each plant can be owned by a separate partnership consisting of Kiwetinohk and financial and/or utility partners. KEC expects to fund and do the so-called, "development" phase of projects. The following achievements are included in the development phase:
   - secure the front-end engineering and design (FEED),
   - environmental impact evaluations,
   - construction and operations plans,
   - Indigenous community and stakeholder (including regulator) approvals,
   - site acquisition,
   - arrangement of utility connection and supply contracts including (as required) power, water, natural gas, carbon dioxide collection,
   - grid connection plans and their stakeholder and regulator approvals, and
   - arrangement of financing.

   The development work includes a significant risk of dead ends. In the conceptual business model that KEC has used to plan its energy transition business, partners with a lower cost of capital and lower risk tolerances are expected to fully fund the next phase, which is the construction of each plant. KEC expects to retain economic interests that reflect the risk it assumes through financing and performing the development phase. To finance its activities, KEC is open to other construction funding proposals or even to sell some of the approved construction plans. Regardless of who ultimately owns them, the plants are part of an energy transition plan that KEC feels suits Alberta's energy and sequestration resources.

5. ***KEC has a financial model that fits its role as a development phase specialist. Still, the Company is flexible and nimble, willing, and able to adjust to a partner's needs and to adapt to evolving market conditions.*** If a business is successful in exploiting a gas field or building clean energy plants, it will overcome the inherently higher risks that apply to the early stages of the projects. This riskier early-stage situation is most compatible with high-cost capital. Some utility investors are satisfied with lower returns if front-end risks have been removed. Others, focussed on investing in the early development phase, will plan and organize later phases. These early-stage developers take on higher, early-stage risk in exchange for a higher investment return. KEC, with its team of project development experts, is presently focussed on managing the risk encountered early in a project's life, with the associated expectation of higher returns. As any of KEC's projects mature through the development, construction and then commercial operations processes, the best ownership might be lower cost, more risk averse capital. KEC is well-suited to overcome early-stage risk. After a positive FID, for the construction phase, KEC's power plants and carbon dioxide storage facilities will cost more than KEC aims to invest directly. One way of achieving its purpose with its relatively high cost of capital could be for KEC to shepherd projects through the development phase and then sell an interest in its projects when they have matured to the point that they are attractive to lower-cost capital. In its financial model, KEC funds the development phase and vends the project into a partnership. Financial and/or utility partners then compete to contribute cash for stakes in the partnership. The partnership then manages the construction phase

of the operation and subsequent commercial operations. Each plant can have a different partnership. With this financing mechanism financial interests in projects reflect risks managed by and capital contributed by each partner. KEC's power team members have experience with this financial structure. It has always been considered by KEC to be the most likely financial model for financing construction of its first power investments. While this model remains Kiwetinohk's basis for project evaluation, the Company recognizes that it needs to be nimble. KEC believes that value is being created by its efforts. KEC will test capital markets to assess alternatives for capturing incremental shareholder value. The objective is maximizing shareholder value – the nature of the deal that accomplishes the objective is flexible.

Table 1 Component businesses of Kiwetinohk's full energy transition business

	KEC Component Business	**Status** (as of Q1, 2024)
1	Natural gas development, production and processing business including water sourcing for hydraulic fracture purposes and produced water disposal.	1 gas field secured, producing 27,566 boe/d during Q1, 2024 including approximately 40,000 boe/d capacity and with estimated up to hundreds (unrisked) of future drilling locations.
2	Natural gas-fired peaking power plant business that can rapidly and efficiently respond with a broad range of power output to meet the fluctuating needs of Alberta's power grid ("Peaker"). Able to add grid stability as total generation becomes increasingly volatile due to anticipated increases in intermittent renewable generation.	2 plants: 1 plant at AESO Stage 5 and 1 plant at AESO Stage 3 One plant may include a carbon capture system that extracts much of the carbon dioxide from the power generation equipment's exhaust stream.
3	Natural gas-fired combined cycle power ("NGCC") plant business that can very efficiently and reliably provide, steady, low-cost, base-load electricity including carbon capture.	2 plants: 2 plants at AESO Stage 3
4	Carbon dioxide gathering and long-term storage ("CCS") business that collects carbon dioxide from KEC's NGCC plants and from various other CO2 producers (if each can be included profitably) and disposes the carbon dioxide into deep aquifers.	2 plants ("Carbon Hubs") in pre-FID planning and regulatory application – KEC's 10-year goal is sequestration of a volume of carbon dioxide equivalent to 90 percent of the production from its own gas-fired power and natural gas-to-hydrogen plants.
5	Hydrogen business that produces hydrogen gas, a clean fuel able to replace fossil fuels in some uses and an input chemical for some oil refining and petrochemical manufacturing processes.	No active projects. 1 natural gas-to-hydrogen plant in conceptual evaluation with an existing customer/partner.
6	Solar energy business, possibly co-locating with 3rd party-owned and operated agrivoltaics (the simultaneous use of land for agriculture and solar energy capture), intermittently generating green electricity.	3 projects: 1 plant at AESO Stage 4 and 2 plants at AESO Stage 3

6. ***Accommodate co-location of complementary businesses to form circular economy hubs.*** To an optimal degree, physical integration of complementary businesses may be incorporated into KEC's energy transition business hubs. This could include co-locating with businesses that need what KEC has or is, in the future, expected to have. Depending on the plant, the opportunities for this vertical integration may include a subset of these commodities: natural gas, natural gas liquids, carbon dioxide, hydrogen, electricity, heat, water, as well as these services: carbon capture and sequestration and industrial water sourcing, treating and disposal. KEC has disclosed its desire to accommodate such synergistic co-location. Businesses with whom KEC has discussed co-location include forest products, hydrogen, ammonia, biofuels, methane pyrolysis, single-cell protein animal feed, Lithium-ion concentration to make a marketable brine, and carbon

dioxide enhanced oil recovery. Related to this point, KEC periodically reviews opportunities to expand the scope of its own business both conceptually and in response to specific business development initiatives. So far, the Company has evaluated to some degree but elected not (yet) to expand the business by incorporating such additions.

7. ***On one hand, the electricity generation industry will likely deploy energy transition capital with caution until governments reach a consensus on policy. On the other hand, because of the magnitude of potential impacts of climate change, policy re-consideration is likely a new normal.*** Electrification is a key strategy in reduction of carbon dioxide emissions. New, low-emissions power plants are needed. Kiwetinohk's underlying electricity generation strategy reflects a response to the Company's view of future government policy for energy in Alberta, Canada. It is entirely appropriate that governments periodically re-visit relevant policy considering changes brought on by climate change. Climate change-related policy has been in discussion at both the Federal and Provincial levels since a time before Kiwetinohk was conceived. In the final analysis, Canada's economy is heavily dependent on trade with the USA and so policies of Canadian governments need to consider the need for Canadian export products to be competitive in the US market. KEC's strategy reflects KEC's views of logical government policy deliberation outcomes. The Company expects to have the nimbleness to adapt as policy is defined and then re-defined.

   KEC moved ahead of policy clarity to capture and manage seven no-to-low emissions power plants through the development phase. New electricity generation opportunities normally arise infrequently. These opportunities arose because of Alberta's recent coal-fired power phase out and, KEC believes, the impending electrification of energy distribution and use systems. The Company believes that the energy transition will require these plants. Kiwetinohk predicts that, ultimately, the energy transition will mandate the future replacement of most, if not all, direct, consumer use of hydrocarbon fuels. KEC predicts that clean energy, in the form of electricity and hydrogen, will substitute for fossil fuels across the economy in the coming decades. Policy remains in dispute among political parties and levels of government. Jurisdiction also remains unresolved. This lack of direction creates uncertainty which the Company believes opens opportunities for developers, like KEC, to advance new projects. Unfortunately, uncertainty and political turmoil may also depress market interest in Kiwetinohk shares.

   Kiwetinohk believes that competition among businesses to provide clean, reliable, dispatchable, and affordable energy will benefit consumers. KEC is preparing for a future in which competition among generators, if encouraged by policy, is likely to result in energy at lower cost and with lower greenhouse gas emissions through innovation and efficiency. Alberta's electricity system is largely held by private companies whereas Canada's other provinces have mostly opted for government-owned utilities. KEC hopes that the two levels of government (federal and provincial) expeditiously agree on a set of rules that unleash the Alberta energy industry to meet society's greenhouse gas emission objectives. Although the Company comfortably contends that all six components of its business plan are necessary for the energy transition in Alberta, at this time, disagreement among policy makers appears so intense that it is hard to invest more than the minimum capital required to keep the projects alive while the governments consider the future of energy and how to achieve it.

Appendix B: Capturing and financing the energy transition investment opportunity.

Kiwetinohk does not need to own its proposed plants to fulfill its purpose of building a company that profitably provides customers with clean, reliable, dispatchable, and affordable energy. At least in the early years of the 10-year strategy, as disclosed at the time of our TSX listing, KEC expects to need a combination of project equity and project debt to finance each of its power and CCS projects. It is conceivable that the best choice for Kiwetinohk may be selling a whole project or even a share of KEC's power and CCS divisions. A transaction will be consistent with KEC's purpose if it contributes to maximum KEC shareholder value realization and ultimately contributes to the cleanliness, reliability, dispatchability and affordability of Alberta's grid power.

KEC has engaged a financial advisor to aid in finding capital for its most advanced projects including Project Homestead (solar array) and Project Opal (gas-fired peaker). Together with the advisor, the Company is considering financing of the projects individually, (e.g. Homestead, alone), in groups (e.g. Homestead and the similarly advanced Opal project) or as a whole power and CCS division. The best outcome may require dividing the Company into two or more separate and independent companies. Appropriate capital market investigation will determine what can be done. The desired outcomes are:

1. Financed energy transition projects,
2. Financed power and CCS divisions of Kiwetinohk
   (the upstream business is capable of self-financing at this time),
3. Revised ownership and financing structure that meets investor needs and facilitates financing, as needed, in the future,
4. Maximized three-year shareholder value outlook, broadly within the ten-year strategy, and
5. Revised 10-year strategies and goals.

Sources and uses of capital: As described in Appendix A, KEC has identified and advanced the development phase of seven large power generation and two carbon capture and storage projects toward the unique FID for each one. The Company is preparing to deploy substantial capital consistent with both the seven projects that are advancing toward FID in the short term and the yet-to-be-sourced projects that are needed to achieve the Company's ten-year strategic objectives. Financing the projects alone, is insufficient. The power and CCS divisions need funding for general and administrative expenses (G&A) and for the development of additional projects.

Possible sources of capital to fund power and CCS projects include:

- Free cash flow as it becomes available when the first power projects reach their Commercial Operation Date (COD),
- Debt (incurred at the project level or the corporate level if the power and CCS division is spun out as a separate company),

- Equity (invested for a share of the project, group of projects, the division, or the power and CCS corporation), and
- Proceeds from the sale of assets or interests in assets (power and CCS).

In the case of funds raised at the corporate level, debt or equity, the corporate entity is unlikely to be Kiwetinohk as it is constituted today. It may be that the best course of action will be to split the Company into two or more corporate entities that could each then go on to secure financing in a way that best fits each one. So far, KEC has devised its power and CCS plans and forecasts using the partnership financing model wherein partners join KEC in the ownership of each project as it reaches FID by buying sufficient partnership units to cover the equity portion of the FID to COD (mainly project construction) capital requirements.

Something seems unreasonable about KEC's share price. KEC's upstream assets, are independently appraised at a higher value than the stock market ascribes to the whole Company. In the recent range of $10.65 to $13.00, Kiwetinohk's shares trade well below the beginning of the year, debt-adjusted reserve values of $33.12 per share for Total Proved Plus Probable Reserves NPV 15% after tax and $25.56 per share for Total Proved Reserves NPV 10% after tax as derived from McDaniel and Associates Consultants Ltd. year-end 2023 estimate[2]. These Independently assessed reserve values attribute zero value to the power generation business. Zero value seems too low. Further, the Company believes that, aside from any value loss due to political uncertainty as previously described, the progressed approval status and advanced plans on the seven most advanced power projects should have some positive market value. The previous appendix describes how uncertainty about government policy direction highlights risks which the Company believes may depress market interest in Kiwetinohk shares. Other factors such as those tabulated on the next page likely influence share demand also.

[2] Based on McDaniel & Associates Consultants Ltd. reserve evaluation report dated March 5, 2024, and effective December 31, 2023 ("McDaniel Report"). The price forecast used in the McDaniel Report is the three-consultant average forecast prices of McDaniel & Associates Consults Ltd., GLJ Ltd. and Sproule Associates Limited as of January 1, 2024. The dollar per share is calculated by the McDaniel Report NPV value less net debt on December 31, 2023. Net debt is a non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities.

Factors that could be expected to apply upward pressure to the share price relative to upstream peers	Factors that could be expected to suppress KEC's share price relative to upstream peers
• Quality Duvernay and Montney resource assets	• High capital cost wells (but strong economics)
• 151 booked and 343 unbooked drilling locations	• Lack of liquidity due to small public trading float in stock market
• Unbooked/undiscovered resource addition potential	• 63.1% shares owned by one private equity shareholder
• Well design value optimization potential (Appendix D)	• Previously mixed drilling and completion results
• Owned processing infrastructure with unused capacity	• Delays and cost escalation in power division
• Access to Chicago and Alberta markets for gas	• Regulatory/government uncertainty due to climate change
• Quality assets in focus region for merger acquisition activity	• KEC has not paid a dividend to shareholders due to its pursuit of a capital intensive growth model
• 39 of top 100 Duvernay wells as measured by average productivity during the first 180 days	• KEC carries a net debt to annualized adjusted funds flow from operations ratio of 79% of at Q1/2024
• Nearly all land is 100% KEC ownership	• The project financing model used for power and CCS project planning has been stressed due to increases in both financing costs and interest rates
• Power & CCS projects	
• Approximately 45% liquids in upstream products	
• Grew production 143% 2024 est./ 2021Q2	
• Earned 26% on average capital employed in the last 2 years	

These observations led KEC to conclude that the aggregate debt-adjusted market value of its upstream, power generation and carbon capture and storage assets, on a per share basis, may significantly exceed its current share trading price. This observation has been a factor discouraging the Company from issuance of shares to advance the upstream business plan more rapidly. The Company is exploring means of getting increased value recognition.

KEC remains committed to the objective of maximizing shareholder returns. Market testing some of our assets might shed light on where, within Kiwetinohk's portfolio of assets, the Company can generate the most future incremental shareholder value per dollar spent and for which assets, Kiwetinohk's best choice is to sell.

Appendix C: Social License to Operate

Kiwetinohk defines “stakeholders” as people or groups who, along with Indigenous communities, can significantly impair or enhance the Company’s pursuit of its goals. Kiwetinohk also holds that allies can often be made of potential opponents through inclusion of stakeholders and Indigenous communities in the planning function. To Kiwetinohk, ESG is about ethically engaging stakeholders and Indigenous communities in ways that maximize benefits to the Company. Through proactive engagement of stakeholders and Indigenous communities, each driven by different motives, strategies that benefit multiple parties are often revealed.

Kiwetinohk’s *Prime Directive*, the backbone of its Code of Conduct, compels its staff to consider Indigenous communities and these eight stakeholders when making decisions about the business:

1. People, everywhere, who seek to protect the environment,
2. Governments and regulators,
3. Communities most impacted by the Company’s activities, including Indigenous communities,
4. Industry partners,
5. Customers,
6. Suppliers and service providers,
7. Employees, and
8. Capital providers.

Kiwetinohk’s activities relative to this policy are described in its ESG reports.

Kiwetinohk has an Indigenous advisory group. It consists of several Indigenous people from the regions where Kiwetinohk operates gas-producing assets and is planning to build power and CCS projects. The group also has a member from southern Ontario who the group welcomes to bring a broader perspective. The group asked the Company to disclose some of its Indigenous engagement activities to the public. Aside from routine meeting with Indigenous communities about our existing and proposed activity in their traditional territory, including the engagement of Indigenous owned and staffed businesses, here are Kiwetinohk’s main Indigenous engagement activities:

- Three Indigenous people participated in a gas field operator training program. All three finished the first phase of the program. One accepted a job offer from another company (which KEC considers a successful outcome). Two remain with KEC. The Company recently extended the program by hiring two more Indigenous people.
- KEC sponsored and served the Saturday evening meal at the Sturgeon Lake Cree Nation Pow Wow in both 2022 and 2023.
- KEC sponsored $100,000 in a microloan agency supporting Indigenous entrepreneurs.

- KEC sponsored a $50,000 share and coordinated a regional industry golf tournament which raised approximately $600,000 for 2023 wildfire damage relief for the Sturgeon Lake Cree Nation.
- The Indigenous advisory group mentioned above.
- KEC has engaged numerous indigenous people from Treaties 7 and 8 to train Kiwetinohk staff in Indigenous history and culture by telling their own life stories.

Appendix D Gaining incremental value through well design modification.

Results of tests done to date, in pursuit of better performance of Duvernay wells, are generally encouraging. (There have not been enough new Montney wells to draw any conclusions yet.) KEC believes that it can add productivity in proportion to increases in lateral length. KEC frequently observes hydraulic fracture ("frac") responses in the production in offsetting wells, possibly suggesting lateral spacing can be increased. Frac response between wells in a very short time interval between commencement of frac pumping and parent well response may suggest that the stimulated volume is small and often directed in the expected SW-NE direction. This observation tends to validate an industry trend to smaller, more closely spaced fracs. This well design may bring benefits of increased vertical access to more of the Duvernay interval, as fracs divert away from the stress shadows of earlier fracs. Elaboration follows.

At this stage in the development of the Company's upstream natural gas asset in Fox Creek, KEC's plan is to test aspects of well design including well lateral spacing and drilling, completion, and production operating practices (collectively, hereinafter referred to as "well design"). Kiwetinohk's well design strategy is to perform incremental tests of well designs, improving the Company's understanding and collecting marginal gains, in the long-term pursuit of maximum value realization. In the upstream petroleum business, Kiwetinohk generates value by developing land. KEC can grow value by adding land and/or developing land it already owns more profitably. The Company's well design improvement efforts are aimed at adding value to the land that it owns. Like many analysts, KEC's evaluators sometimes use, not value realization, but other measures such as capital cost per well or capital cost per boe per day of production as proxies for value realization. These shortcuts sometimes mislead as to the true value gain. An easy example is to consider the benefits of doubling lateral length, all else remaining the same. KEC would expect the total well production and recovery to about double from the shorter to the longer well. KEC would expect doubling lateral length from 2000m to 4000m to cost considerably less than double. Analysts, comparing our cost to less adventurous developers who chose to stay with 2000m laterals, might highlight that KEC's costs per well are much higher than its peers' cost per well. The Company tracks profitability and makes well design test decisions in pursuit of profit potential of its land base.

Kiwetinohk's purpose is to build a company that profitably provides customers with clean, reliable, dispatchable, and affordable energy. Maximizing achievement relative to that purpose is at the base of Kiwetinohk's strategic decision- making. The key specific goal, constituent to the above overall statement of purpose, is to, with environmental and safety excellence, gain either or both of two benefits:

1. Reduced impact of surface land disturbance on wildlife species at risk, especially a herd of caribou, in Kiwetinohk's Fox Creek development area, that is protected under *species at risk* legislation, and
2. Increased profit from the development of the Company's land base.

Fortunately, the above objectives are generally aligned. KEC hopes to be able to use less surface land by draining more resource from each well pad. Specifically, the Company is targeting:

- Increased lateral reach from the surface wellhead to the point at the heel of any well where the last hydraulic fracture (frac) occurs (this distance is called "displacement" in the industry),
- Longer horizontal lateral length between the frac closest to the toe and the frac closest to the heel,
- Increased effective reach of the fracs from the wellbore into the resource, enabling more profit from reduced well capital cost, with an anticipated profitability compromise in drainage from more widely spaced well laterals, and
- Increased intensity of the hydraulic fracture network and better flow connection of that network to the liner.

Each of these changes is expected to improve deliverability and recovery per well.

Kiwetinohk's well design economic goal is to increase its net present value per unit of developed land area. Pursuit of that objective is likely to include attempts to optimally drain more petroleum per well by making the drainage area of each well longer and wider – both costing more per well. Individual wells are likely to be more expensive but fewer wells could ultimately be required to maximize the value of the Company's leased petroleum rights. KEC's success may also enable fewer, more widely separated well pads, which will also reduce the area needed for roads, pipelines, power lines, and pad surface facilities. Kiwetinohk pursues benefits for shareholders by means aligned with the interests of some of its other stakeholders who are more concerned with minimizing surface land disturbance.

The Company holds the view that incremental tests of displacement, lateral length, and frac length place relatively small increments of land and capital at risk. If a test fails to produce the desired result, the penalty is likely to be reduced profitability of the test well investment via some combination of reduced productivity, reduced recovery, or increased well cost. (Also, possibly, some reduction in fracture effectiveness may result if the Company reduces fracture size and pump rate and skips some intended fracture stages in response to a higher-than-expected amount of seismic activity.) Complete loss of a well investment is likely to be a rare event. Conversely, if a test works the newly discovered incremental improvement can likely be applied to many future well designs. This opportunity for repetitive application of profit-enhancing results tilts the benefits heavily in favor of testing over the alternative of changing only to mimic the most successful designs of other operators in the region. Having stated the foregoing, KEC expects to learn by observing the well designs and results of other operators.

Resource properties vary over the drilled area of the Duvernay and Montney formations. The result is that optimized well design and operating practices on one pad may not be optimal for others. These uncontrollable rock properties include depth, pore pressure, saturating fluids (gas or oil and their respective components), porosity, stratification, geo-mechanical properties, mineralogy, initial *in situ* stresses, etc. While the Company is likely to learn overall and regional trends, learning to accurately forecast future production of any given well design at any given location is unlikely. Understanding how to improve wells that immediately offset test wells is likely. KEC expects to gain understanding that enables well design improvements that apply more broadly. In both cases, nearby and regional applicability, learnings are likely to remain probabilistic as to magnitude, not definitive in nature. This phenomenon of multiple further applications of any successful test contributes greatly to the prudence of the Kaizen strategy (Kiwetinohk's pursuit of continuous improvement). This strategy and the reasoning supporting its adoption seem to be common among shale resource developers. Well designs have evolved greatly over the last decade since the early days of the shale gas development boom. Investor presentations and analyst reports continue to feature descriptions of improved results, achieved from testing incremental changes in well design. The industry continues to find improved well designs. In fact, the evolution of well designs has improved development economics for successful companies whose achievements are celebrated in investment literature. Other companies have seemed to stand still, offering an unimproved value proposition to a less receptive investment world.

Why is there a concern about this issue?

Much of Kiwetinohk's Fox Creek resources underlie sensitive habitat for protected species. In fact, in much of the Company's operating area, access to construct roads, pads and facilities or to drill, complete and tie in wells is limited by regulation to seven months of the year. The regulator intends that limiting access will protect a herd of caribou that is designated a species at risk. (There is a provision in the regulation whereby an operator may be granted specific relief to complete operations underway at the end of the seven-month open-for-activity period.) So, KEC's resources can be developed as the regulations are currently written and administered but an erosion of economics results from interrupting and prolonging operations. There is also a risk of much stricter access restrictions being imposed.

The Company's vision for the Fox Creek property includes the development of both Montney and Duvernay assets. KEC owns a large amount of property where it appears that both formations have potential. In the region, there are multiple owners of rights to develop each of the Montney and/or Duvernay (and some other formations too). Both formations have areas within KEC lands where the condensate (or oil) to gas ratio is very high. When thinking about future development, KEC considers a significant probability that it will be able to enhance recovery of some portion of the resource with the cyclic injection of natural gas, ngl or carbon dioxide (with responsible re-capture of the produced carbon dioxide) and, possibly, re-injection of produced water. The area's resource potential leads to the possibility of a lot of development with well pads for both Montney and Duvernay wells connected to surface facilities. These facilities could include hydrogen sulfide gas extraction, liquids separators and compressors to provide sweetened gas for gas lift and cyclic injection. It is likely that additional storage ponds for water needed for drilling and completions as well as water source wells will be required. Central facilities to gather, separate and dispose the produced water and condition the hydrocarbons to sales specifications are already there and additional facilities may be required. Future additional well pads and facility sites will need to connect with roads, pipelines, and power lines. Picture this kind of development with multiple companies each needing, to some degree, their own operations.

The petroleum industry needs to conserve habitat for species at risk while, at any given location, multiple developers seek to advance the development of their own lands. Without some coordination and planning, the habitat fragmentation resulting from development could add to regulatory concern and enforcement regarding species at risk. The industry may not need as much surface land if it can drill longer wells and it can reach out farther with the vertical portion of the hole to reach more distant heels of horizontal wells.

How big is this issue?
Federal and Provincial governments have overlapping jurisdiction on this issue. In addition, elsewhere, a Montney development was recently severely constrained when courts determined that cumulative effects leading to increased habitat fragmentation in that area infringed on an Indigenous community's right to traditional land use.

What are the most significant surface land disturbance reductions to be achieved in well design?
The responsible approach for Kiwetinohk is to plan development with the goal to minimize habitat fragmentation as a foremost consideration. Among other measures, this means specifically looking to reasonably minimize surface disturbance by exploiting more subsurface resource area from each pad. To achieve that, we could benefit from increasing the drainage area of each well by increasing both the length and width of the drainage area. That probably means that wells with longer laterals and farther-reaching fracs are desirable.

What well design parameters are KEC testing and what are the goals?
The well design parameters that KEC is testing and the related goals KEC is seeking are tabulated along with key associated risk considerations in Table 2. As the listing in Table 2 shows, the Company's land disturbance goals are generally aligned with its profitability goals. Of course, many of the factors that influence the performance of a well (e.g. fluid and rock properties) are not controllable. Varying the controllable parameters may influence the economics within constraints imposed by the uncontrollable factors.

Why do we think the reward may outweigh the cost of the associated testing and development risks?
The desire to prioritize testing well design parameters arises from looking at statistical data from the history of well designs in KEC's zones and operating regions as well as observations from similar reservoirs and from KEC's conceptual models of how hydraulic fractures work.

A key motivator for the Company to conduct experiments in search of better well designs is the probability that learnings on any one well might profitably be applied to many future wells. It is often difficult to attribute the performance of any well to a design change. Natural variation in resource properties and well to well changes in controllable parameters, together, eliminate the ability to isolate and measure the performance due to any one parameter. Some evidence suggests that the industry has been able to isolate some cause-and-effect relationships with controllable well design parameters in the

Montney formation in the region. So far, pursuit of quantification of the impact of well design alternatives in the Duvernay has been more difficult.

Table 2 Key well design parameters being tested in pursuit of better performance

Well design parameter	**Environmental goal**	**Profitability goal**	**Key risk considerations**
Wider well/lateral spacing	Fewer wells and further pad spacing, less surface disturbance	Fewer wells and associated capital per area of development, per boe of recovery, more boe recovered and more land developed per well.	Risk of reduced overall recovery necessitates effort to install longer (higher slurry volume, higher pump rate) fracs with inherent risks.
Further lateral reach from wellhead to heel of lateral (known as "displacement" in industry terms)	More area drained from one pad, less surface disturbance	Fewer pads and less associated costs for roads, pipelines, and power lines.	Increased drag may reduce the economically achievable lateral length.
Longer laterals	More area drained from one pad, less surface disturbance	Fewer pads and less associated costs, road, pipelines, and powerlines. Fewer wellheads and expensive vertical portions of wells. Increased recovery factor at time when well productivity declines to its economic limit.	Lateral cost is likely to escalate rapidly at some length, likely unique for each well. May be able to reach farther with drilling than with completion equipment. Complexity related risk.
Economically optimal frac spacing along the lateral	Reduced well life from faster resource extraction enables lower time interval between disturbance and reclamation.	Maximized profitability by optimizing the compromise between capital cost and productivity / recovery.	Probably need large test sample size over long period to find optimum.
Larger frac slurry volume along with higher frac slurry pump rate	Longer frac, wider well spacing, fewer wells and pads, less surface disturbance.	Longer frac, wider well spacing, more area drained per well and per pad, less capital.	Risk of reduced rate and recovery due to increased leak off near liner. Risk of larger volume of unstimulated reservoir.
Higher proppant intensity (kg/m)	Wider lateral spacing / less wells to drain a given area.	Longer frac length held open and effective for longer life, more profitable rate, and recovery profile.	Increased risk of screen out (plugging while pumping frac) leading to loss of frac injectivity leading to costs and lost frac effectiveness.
Fluid additives	Use less fresh water. Produce less brine with environmental damage potential if spilled during handling.	Source, handle and pump less fresh water while fraccing and produce less brine that must be disposed, saving capital and operating costs. Possibly more profitable rate and recovery profile.	Minor increased risks if additives spilled. Additives might plug the flow pathways within the resource rock and impair production.
Optimal flow back rate	More recovery per well, potentially less wells required to drain a given area.	Higher recovery from optimizing cracking due to pressure gradient during production and effective mobile solids lifting. Increased recovery at time when well productivity declines to its economic limit.	Unpropped fracture collapse with risk of damaging flowrate of well. Under achieving flowrate relative to potential. Insufficient pressure gradient to cause optimal breakage of rock.
Vertical position of the lateral within the formation (a.k.a. landing depth).	Maximize recovery of hydrocarbon per amount of surface disturbance.	Maximize recovery of hydrocarbon per amount of capital expended.	While producing the well, fracs may close and cease effectively connecting some strata to liner, leaving those strata ineffectively drained.

Cause and effect relationships are hard to derive from statistical data because consistent test and control populations probably do not exist and because the Duvernay resource varies considerably from well to well. Ideally, the Company would have a control group of several wells completed identically in identical reservoir offset by wells with identical history thus enabling a test group in which the only difference was a single variable. There are no data with those characteristics. There are two analytical processes that can be used to employ the available data:

- Advanced statistical processing methods might be used to isolate and identify well designs that correlate best to control parameters or
- Basic science could be used to formulate a conceptual model and from that model, the Company's well design team could anticipate cause and effect relationships and then look for evidence of them in the data.

So far, KEC has been pursuing both analytical processes, with emphasis on the use of a conceptual model. The following are some key concepts within that model:

- ***Montney fracs likely line up perpendicular to the Rocky Mountains. The Duvernay fracs likely have the same tendency but with less consistency.*** The Montney and Duvernay exist in stress states due to the geologic history of the region and the depth of burial. Imagining three dimensions of stress, vertical stress due to the weight of the overlying geologic strata and then two principal horizontal stresses due, mainly, to the ability of the rock fabric to translate the vertical stress in the horizontal direction. (To illustrate, imagine standing on two tiles, one made of porcelain and the other of plasticine. The strong and brittle porcelain tile would not perceptibly bulge sideways under your weight while the plasticine might extrude until your shoe contacts the underlying surface directly.) Ductile formation rocks such as clay-rich shales, like plasticine, translate vertical force horizontally more effectively than strong, brittle rocks such as dolomitic siltstones. Additionally, the compressive forces pushing Alberta into British Columbia that resulted in faulting and uplift of the Rocky Mountains still exist at some elevated level today. The result is that most often the highest horizontal stress is perpendicular to the Rocky Mountains and the lowest horizontal stress is parallel to the Rocky Mountains. From our observation, this stress situation is generally true for both the Duvernay and the Montney at Fox Creek. Our response to this tendency in the natural stress field is to prefer to drill the laterals of our wells along a northwest - southeast direction, parallel to the Rocky Mountain chain. In our conceptual model, the fracs will most often have a bias to propagate perpendicular to the Rocky Mountains, generally northeast - southwest. Fragmented land ownership and existing well orientation considerations sometimes make drilling wells in the preferred direction impractical. For this reason, some of our newer wells in Placid, like their predecessors, have laterals parallel to the Alberta land survey grid. The dominance of the horizontal stress in the direction perpendicular to the Rockies is less obvious and less predictable in the Duvernay, where faulting has redistributed stress leaving the relative magnitude and direction of the maximum and minimum horizontal stresses within the Duvernay less obvious and less consistent. As a result of the varying direction and relative magnitude of the Duvernay horizontal stresses the direction of the fracs and even the consistency from frac to frac within a well is less predictable. The Duvernay, in KEC's Simonette region may fracture in a multi-directional array of cracks.

- ***Fracs are likely to be open cracks in a vertical plane bounded at the top and the bottom by weak mechanical boundaries.***
  Petroleum shales are sedimentary rocks that were generally deposited in layers. Post-depositional events caused changes to the lithology and mechanical properties of the layers. The resulting layers of lithology and mechanical properties exist within the formations today. Some layers resist breakage along bedding planes while others break more readily. Some layers have natural fractures while others have altered permeability due to interaction with migrating fluids. Fracs tend to grow vertically until they encounter layers of rock with contrasting stress and relatively weak resistance to failure ("weak mechanical boundaries"). Since the maximum stress is most often the vertical stress, the weight of the overlying rock, it is difficult for fracs to grow with much of a horizontal component to the fracture plane. The vertical growth of fracs is impaired by layers of rock with high ductility that more effectively translate the higher vertical stress sideways. The simplest conceptual model is a vertical planar geometry in brittle rock, confined at the top and bottom by weak mechanical boundaries e.g., clay-rich shales, stiff carbonate units, etc.
- ***The plane of a frac is likely to extend both directions from the liner.***
  Injecting a fracture fluid to break the rock, establishes, in KEC's conceptual model, a vertical fracture that grows laterally both directions perpendicular to the least horizontal stress between confining mechanical boundaries such as clay-rich shales and stiff carbonate units. The natural stresses in the rock, not the orientation of the lined wellbore, dominate in controlling the orientation of the fracture plane.
- ***Frac volume grows when the rate of fluid pumped into the frac exceeds the rate of fluid dissipation from the frac into the surrounding porous rock media.***
  The fracture grows to accommodate the volume of the fracture fluid. The fluid volume that needs to be accommodated is the net injected volume after considering fluid that dissipates from the open frac into the rock media (through interconnected pores and natural and induced fractures, etc.). The dissipation rate of fluid from the frac into the rock media thus imposes a limitation to fracture growth. Once the fracture has grown to a volume that exposes enough rock media to dissipate fluid at the same rate it is being pumped into the frac volume, the growth of the frac stops. This is why KEC thinks that, with higher rates and higher frac slurry volumes, it can generate longer fracs. This is also why KEC thinks that, with longer fracs, it can effectively drain the petroleum from distances further from the lateral thus enabling extended lateral spacing. This thesis is not without risks, some of which are:
  - There is a risk of damaging offsetting wells (called "parent wells") or their equipment by collapse of the parent lateral or by filling the parent lateral with rock debris or frac proppant.
  - There is risk that the increased frac volume may not provide economic benefit due to the frac growing into and connecting rock media that is not hydrocarbon-bearing.

- There is also a risk that the frac height diminishes with distance from the liner, impairing the frac's ability to drain much of the hydrocarbon bearing formation that is relatively distant from the liner.
  Kiwetinohk is evaluating frac spacing.

- ***We may be able to find a low-cost, environmentally friendly additive for our frac fluid that will reduce frac fluid dissipation into the rock, diverting more of the injected fluid to frac growth.***
  As the frac grows the area of rock available for frac fluid to dissipate grows. If the Company can find a fluid with a lower tendency to dissipate into the rock, then more of the fluid pumped can serve the desired purpose of frac growth. That can yield some combination of lower water use and longer (and taller at distance) fracs. These characteristics are aimed at reducing both cost and freshwater use. To achieve the desired result, the fluid must have qualities that keep it from impairing the well's production. KEC is experimenting with frac chemicals.
- ***The horizontal stress field in the resource rock determines the frac orientation and the tendency toward a two-dimensional planar geometry or a three-dimensional, waffle-like network.***
  In our conceptual model, applying enough hydraulic force to break the rock creates a region of high stress from the frac face back perpendicularly into the rock for some distance. The distance depends on the properties of the rock and the pre-existing stress state. The facial stress concentration dissipates with distance from the fracture face into the body of the rock. The rock with a significantly altered stress field due to the nearby frac, is termed to be in a *stress shadow*. Fracs will likely not be influenced by previous fracs if they are far enough apart to be out of the stress shadow. KEC's specialists get a sense of whether fracs are in the stress shadow of previous fracs by the pressure profile required to initiate and pump the fracs. The stress shadow can create a situation in which the rock breaks more easily in a vertical plane that is perpendicular to the plane of the previous frac. In the Duvernay, where KEC believes that the minimum and maximum horizontal stresses are not always dissimilar, KEC sees evidence of fracs initiating and connecting with previous fracs. This horizontal stress isotropy may add a third dimension in fracs, essentially a web of interconnected vertical fracs. When a frac does not occupy the full vertical interval of the resource rock, stress shadows might be exploited to divert a later frac up or down out of the stress shadow of the previous frac. KEC is experimenting with frac spacing.
- ***Higher productivity wells should be able to achieve a higher recovery factor both when artificial lift is required and when production declines to the economic limit.***
  In our conceptual model of a well with multiple hydraulic fractures, for most of the life of the well, total well production rate is dominated by flow in the low permeability rock, not by flow in the fractures themselves. The physics of the flow within the rock may be conventional flow in porous media as used by the petroleum industry to predict resource depletion for a century or more. Alternatively, the physics may be something more complex including imposing a pressure gradient during production that is high

enough to crack the resource rock further, thereby altering the flow capacity of the rock. As shale gas depletes its resource rock becomes subject to a high pressure gradient, the result of very low permeability. That pressure gradient may lead to cracking that increases the effective permeability of the petroleum shale. Analogously, heavy oil also sometimes depletes its resource sand subject to a pressure gradient, the result of very high viscosity. In heavy oil, deliberate rapid depletion of the resource often results in production of some of the resource sand and an associated increase of effective permeability in an enhanced recovery process called, *cold production*.

KEC's conceptual model accepts that probably the physics of flow in the resource rock controls the well rates, not in the hydraulic fractures controls the well rates. Logical extensions of this view of the physics include:

- Higher pressure gradients (between the undisturbed rock and the frac) result in cracking of the resource rock, increasing the effective permeability, leading to higher flow rates,
- More total connected fracture face area (by increasing the size of the fracs and/or the number of them) will likely result in a higher well production rate,
- The average resource rock pore pressure will decline as the petroleum resource depletes,
- Generally, wells with more total frac area, will produce at higher rates for any state of resource depletion than wells with less total frac area.

A further extension from the above concepts is the expectation of higher economic recovery factor by making individual wells more productive. (Note that the *economic recovery factor* is the percentage of hydrocarbon in the rock that is produced while the well is producing at a rate high enough for the well operation to be profitable.) This extension is enabled by the economic limit flow rate. The *economic limit flow rate* is the well's rate when the well's marginal sales revenue equals the well's marginal operating cost. Below the economic limit flow rate income is insufficient to cover the total cost because wells have fixed costs that apply regardless of the rate or operating status. When a well with more connected fracture area declines to its economic limit flow rate, the fraction of the resource recovered by the well will be higher. Likewise, the well will have recovered more petroleum when the productivity declines to the point that artificial lift is warranted. Increasing total frac area by increasing the number of frac stages or deploying larger frac stages provides two benefits:

1) higher production rate and
2) higher total petroleum recovery.

Increasing total frac area also increases capital cost. The opposing direction of these profitability determinants (frac area and frac cost) makes finding the maximum net present value an optimization challenge. KEC is testing controllable factors likely to affect productivity and thereby profitability.

- ***Longer laterals have the same benefits as bigger fracs but the conceptual model for lateral length is easier to understand and predict.***

KEC's conceptual model includes the concept that frac spacing and frac size being equal, production and recovery should be roughly proportional to the length of a lateral. Two wells aligned toe to heel, each having a 2000m lateral, ought to perform the same as one well with a 4000m lateral. There are some reasons why the longer lateral might perform better. With long laterals we can get more connected frac area per well benefitting the recovery factor at the abandonment rate and aiding artificial lift just as we would by installing closer fracs in a shorter well. There may be some reduction to rate in longer wells due to frictional pressure loss, especially in the early stage of a very productive well's life, but the conceptual model favors the longer lateral from an overall rate and recovery point of view. From a cost point of view, longer laterals lead to cost savings because less roads, tie-in lines, pads, wellheads, and vertical portions of wells are required. There are some limiting factors to length. It gets hard to get tubulars to depth because of drag (this statement applies to both permanent well tubulars such as the production liner and to work strings such as the drilling string and the coiled tubing needed to drill out frac stage plugs and debris). There are also risks associated with lateral length. Each unit of lateral length has roughly the same probability of operational difficulty (probably a little bit higher at the toe than at the heel) leading to the loss of the toe portion of the well that is deeper than the point where a problem causing the loss of some of the lateral occurs. In longer wells the probable lost length per well is higher. KEC is testing variations in lateral length.

What has the Company tested, observed, and concluded so far?
KEC's testing, so far, has produced some interesting observations that may lead to a higher capital efficiency in future wells. Unless stated otherwise the following comments apply to the Duvernay.

- ***Fracs from new (child) wells frequently interact with old (parent) wells and the volume pumped before a response is observed is often surprisingly small.*** KEC has tested a variety of lateral spacings with the nearly universal result that parent wells respond to fraccing of child wells. (The industry term for a pressure response to a frac at an offsetting well is *frac hit*). Evidence to date suggests that the stimulated rock volume communicates with wells NE and SW of the new well (toward or away from the direction of the Rocky Mountains, as predicted) and there has been less frequent evidence of frac hits with wells to the NW or SE of the newly stimulated wells. The high frequency of the frac communication with the offsetting wells suggests that either or both wells have wide fracture stimulated shapes or narrow fracs are drawn to narrow pre-existing fracs. KEC has observed frac hits at liner separation distances of about 300 metres to about 600 metres. Frac hits have been experienced early in the pumping of a new frac suggesting the volume of the frac can be small. The observation of frequent frac hits over long distances supports KEC's proposition that well to well lateral spacing can be increased but the optimum spacing is still unknown. The Company has yet to determine the relationship between lateral spacing and recovery. KEC predicts that increasing lateral spacing will reduce the recovery factor, but the average amount of hydrocarbon recovered by each well will increase. KEC's target is increased capital efficiency for the development of the Company's resource land.

- ***One explanation for the small pumped volume that is sometimes required before a frac hit is observed suggests the fracs may occupy a very small volume.***
  Although the volume pumped before a frac hit is observed suggests a small volume pathway between the wells KEC has not been able to conclude much about the frac geometry (i.e. how wide and tall is it? does it penetrate a large or small portion of the vertical target frac interval?). The small volume leads KEC's technical team to ponder what percentage of the resource is effectively drained. Can viscosifying chemicals or faster frac pump rates increase the volume of the communication channel between wells? Is there a more optimal interval to place the lateral? Should KEC try to get fracs to choose unstimulated portions of the formation by deliberately spacing fracs in the stress shadow of the previous frac? There is more work to be done but, data gathered to date, encourages reduction of the interval between fracs with the economic compromise of making each frac smaller and less expensive.
- ***KEC has learned to drill and complete to a lateral length of more than 2 miles (3200 m)***
  Many of KEC's new wells are in the deepest part of the developed portion of the Duvernay where expected rock stresses and pore pressures are highest. Evidence suggests that KEC's liners have occasionally crimped to a degree that makes subsequent passage of concentrically smaller tools difficult to impossible. Additionally, KEC had trouble in getting liners to pass points in the open hole. KEC's wellbore designs and success ratio are improving. The last nine Duvernay wells have been successfully lined and completed to full depth with laterals in the range of 2900 to 3700 metres. The potential economic and environmental benefits of longer laterals warrant continuing to experiment with this challenge.

Go forward plan for continuous improvement

Because of the vertical depth of much of KEC's Duvernay (3600 to 4100 meters) the Company is fraccing under some of the most challenging conditions experienced by the Canadian shale gas industry. This means that while KEC can learn trends from watching others, the Company's uncommon conditions may require uncommon solutions. The search for maximized value solutions includes testing. Generally, the expected incremental costs of experiments are small compared to the benefits of the application of what is learned to the test well and to future well inventory.

KEC seeks to increase its profit and reduce its environmental disturbance. Draining a larger volume of rock from each well would probably contribute to achievement of those goals. Early into the program we can draw some significant conclusions:

- Some of the frac hits suggest that at least some of our fracs are small in width and height but long. This suggests small, more closely spaced fracs, pumped at high rates, possibly with a viscosifying agent. might provide effective drainage of an increased distance from the lateral. KEC has observed frequent frac hits over liner separation distances of 300 to 600 metres. This encourages increasing standard horizontal lateral separation distance by a small increment from 300 to the range of 325 to 400 metres (an increase of about 20%). KEC has wells at various spacing with fracs of various sizes. KEC monitors the wells to gather data that will help the Company estimate the effect of well spacing on well production rate and ultimate recovery performance. The decision to increase lateral spacing to improve primary recovery per well must be considered in the context of the possibility that the Company will be able to profitably enhance recovery of condensate and/or oil by cyclic solvent (some combination of gas, ngl and carbon dioxide) injection in the future. A cyclic solvent enhanced recovery scheme might provide maximum profitability with closer spacing.

- The Company is incrementing the horizontal lateral length. The current target is 4500 m (an increase of about 30 percent from recent wells). Modestly increased lateral length and modestly increased lateral separation combine to result in a drainage volume increase of more than 50%. Achievement of these targets has the potential to greatly reduce the number of wells and thereby the total development capital cost to drain the resource. Longer wells cost more than shorter wells. Longer fracs cost more than shorter fracs. To increase the drainage volume of a well, as described, the Company expects the cost of individual wells to increase but not in direct proportion to the increase in drainage volume. This assessment presents an optimization problem with both desirable and undesirable consequences that KEC will need to estimate. Estimating performance of more widely spaced or longer wells will take several test wells and a few years of production from each. This means that decisions will need to be made and refined as the resource is developed, often in the absence of sufficient data to provide a high degree of certainty to projected incremental responses to increments in lateral length and lateral separation.

Advisories

Certain statements contained in this document constitute "forward-looking statements" or "forward-looking information" within the meaning of applicable securities legislation (collectively, "forward-looking statements"). All statements other than statements of historical fact are forward-looking statements. The use of any of the words "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "would" and "potential" 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. Although Kiwetinohk believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements as the Company can give no assurance that such expectations will prove to be correct.

Specifically, this document contains forward-looking statements pertaining to:

- The Company's beliefs and expectations with respect to its business model, energy demands, energy transition, the future of energy and the best strategies for the Company to succeed in the Alberta power industry moving forward,
- Successful execution of the Company’s green energy projects and the impacts thereof,
- The Company's ability to capitalize on certain energy transition opportunities through the use of new, innovative technologies in the market and the resulting profitability of its core businesses,
- Industry conditions pertaining to the hydrocarbon, energy transition and renewable power industries,
- The Company's ability to achieve higher netbacks with high efficiency plants,
- The expected generation capacity and carbon emissions of the Company’s planned power plants,
- The Company’s future drilling locations,
- The Company’s ability to adapt as governmental policy is defined,
- The necessity for future utility scale power plants by virtue of the energy transition,
- Physical integration of complementary businesses in the Company’s energy transition business hubs,
- The Company’s 10-year goal as it relates to carbon dioxide sequestration,
- The anticipated role that clean energy will have across the economy in coming years,
- The Company’s consideration of project and corporate level financing of power and CCS projects,
- The Company's plans for developing a low emission power generation business, including development of solar, wind and high-efficiency, gas-fired power projects and expectations with respect to future opportunities for other renewable energy projects,

- The Company's plans to complete development work in order to advance its energy transition business, with funding for construction from third parties, and the economics relating thereto,
- The impact of competition in the energy industry,
- The impact of various external factors on KEC's share price relative to inherent per share value,
- Progress on the Company's business plan and expected uses of capital therefrom, including deploying capital towards its power and CCS projects,
- The Company's ability to produce and supply desired volumes of power, natural gas, and hydrogen,
- The anticipated results of KEC's policies and strategies,
- Future investment opportunities for the Company,
- The results and benefits of the Company's well design testing strategy,
- Potential returns of and on capital to shareholders,
- The Company's plan to use gas-fired power generation systems that can be converted to hydrogen as the fuel gas,
- The potential for improved economics by using new technology design in the Montney and Duvernay formations,
- The Company's plan for Montney fraccing, and
- The potential consequences of climate change.

Statements relating to "reserves" are also deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves described exist in the quantities predicted or estimated and that the reserves can be profitably produced in the future. Estimates of the Company’s reserves and the net present value of future net revenue attributable to the Company’s reserves contained in this document are based upon the report prepared McDaniel & Associates Consultants Ltd. dated March 7, 2023, evaluating the reserves attributable to certain of the assets of Kiwetinohk and its subsidiaries as at January 1, 2023. Actual reserve values may be greater than or less than the estimates provided herein.

The reserves information contained in this document has been prepared in accordance with National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities ("NI 51-101”).

Complete NI 51-101 reserves disclosure is included in the Company’s annual information form (“AIF”) published on the Company's profile on System for Electronic Document Analysis and Retrieval (“SEDAR”) at www.sedar.com.

The term barrel of oil equivalent (boe) may be misleading, particularly if used in isolation. A boe conversion ratio for gas of 6 Mcf:1 boe is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Developing forward-looking statements involves reliance on a number of assumptions. In addition, forward-looking statements involve a number of risks and uncertainties that could cause actual results to differ materially from those anticipated by the Company and described in the forward-looking statements. For details on these assumptions, risks and uncertainties, please refer to the Company's AIF published on the Company's profile on SEDAR at www.sedar.com, in particular under "Risk Factors".

The forward-looking statements and information contained in this document speak only as of the date of this document and the Company undertakes no obligation to publicly update or revise any forward-looking statements or information, except as expressly required by applicable securities laws.

This document uses Non-GAAP measures including net debt and adjusted funds flow from operations. These terms do not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Non-GAAP and other financial measures presented in this document 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 Kiwetinohk's financial statements. Readers are cautioned that these non-GAAP measures should not be used to make comparisons between Kiwetinohk and other companies without also taking into account any differences in the method by which the calculations are prepared. Additional information relating to non-GAAP measures utilized by the Company, including how the Company utilizes these measures can be found within the Management's Discussion and Analysis of the Company 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.