Management’s discussion and analysis

The following is Management’s Discussion and Analysis (“MD&A”) of the financial performance and results of operations for Kiwetinohk Energy Corp. (“Kiwetinohk” or the “Company”) as at and for the twelve months ended December 31, 2021. The Company was formed as part of the amalgamation of Kiwetinohk Resources Corp. (“KRC”) and Distinction Energy Corporation (“Distinction”). Kiwetinohk’s common shares are traded on the Toronto Stock Exchange under the symbol KEC.

This MD&A should be read in conjunction with the Company’s audited consolidated financial statements as at and for the year ended December 31, 2021 (the “Financial Statements”). Additional information including Kiwetinohk’s Annual Information Form (“AIF”), is available on Kiwetinohk’s website at www.kiwetinohk.com and SEDAR at www.sedar.com. The Financial Statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”). This MD&A should also be read in conjunction with the Company’s disclosure under “Non-GAAP Measurements”, “Forward-Looking Statements” and “Abbreviations” below.

The reporting currency is the Canadian dollar, and all dollar amounts in this MD&A are stated in Canadian dollars unless otherwise indicated. This MD&A is dated March 23, 2022.

Overview of business

Kiwetinohk’s mission is to build a profitable energy transition business which provides clean, reliable, dispatchable, low-cost energy. The Company develops and produces liquids rich natural gas and related products and is in the process of developing renewable and natural gas-fired power generation projects with a vision of also incorporating carbon capture technology and hydrogen production, all as part of a broader, integrated portfolio of clean energy assets that will support energy transition in the markets that it serves.

Upstream

The Upstream business unit is involved in the acquisition, exploration 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 highly competitive economic resource potential. In 2021, the Company completed acquisitions of attractive upstream assets and associated infrastructure. These assets consist of high-netback, liquids rich natural gas production with development upside and substantial spare processing capacity from owned infrastructure. These upstream assets provide a foundational base for the Company to pursue and develop energy transition opportunities.

Green energy

The Green Energy business unit is pursuing greenfield and/or brownfield development of a diversified Alberta-based power generation project portfolio that includes clean, efficient, and reliable natural gas-fired power with carbon capture and sequestration and renewable power sources, including solar and wind. Development work has included preparation of preliminary designs, environmental studies, permitting, consultation, Alberta Electric System Operator (“AESO”) stage reviews and studies, pre-FEED and FEED reviews, performance estimates and preliminary cost projections. The Company’s process of advancing projects involves progressing through stages of review and increasing design refinement and estimate quality with an intent to proceed to final design, full regulatory approval and securing of internal and external funding for projects that prove to meet the Company’s investment criteria. Successful execution of Green Energy projects will enable the production of clean, reliable, dispatchable low-cost energy and provide downstream markets for integration of the Company’s future gas production, allowing it to capture a larger portion of the hydrocarbons value chain.

Financial and operating results

	Q4 2021	Q4 2020	2021	2020
Production				
Condensate (bbl/d)	**3,092**	13	**2,644**	35
Light oil (bbl/d)	**844**	374	**457**	429
Heavy oil (bbl/d)	**13**	43	**29**	15
NGLs (bbl/d)	**1,572**	41	**1,180**	64
Natural gas (Mcf/d)	**41,410**	1,045	**32,942**	1,367
Total (boe/d)	**12,442**	645	**9,801**	771
Oil and condensate % of production	**32%**	67%	**32%**	62%
NGL % of production	**13%**	6%	**12%**	8%
Natural gas % of production	**55%**	27%	**56%**	30%
Realized prices				
Condensate ($/bbl)	**99.21**	55.56	**84.94**	55.47
Light oil ($/bbl))	**92.29**	48.57	**82.46**	48.13
Heavy oil ($/bbl)	**81.60**	35.58	**59.22**	34.40
NGLs ($/bbl)	**65.61**	14.04	**52.60**	7.09
Natural gas ($/Mcf)	**6.64**	2.66	**5.29**	2.28
Total ($/boe)	**61.48**	36.83	**51.06**	34.60
Royalty recovery (expense) ($/boe)	**(6.80)**	1.57	**(5.46)**	(2.14)
Operating expenses ($/boe)	**(8.28)**	(9.94)	**(8.18)**	(9.66)
Transportation expenses ($/boe)	**(5.20)**	(1.06)	**(5.09)**	(0.80)
Operating netback [1] ($/boe)	**41.20**	27.40	**32.33**	22.00
Marketing income ($/boe)	**2.50**	-	**1.91**	-
Realized loss on risk management contracts ($/boe) [5]	**(11.86)**	-	**(10.15)**	-
Adjusted operating netback [1]	**31.84**	27.40	**24.09**	22.00
Financial results ($000s, except per share amounts)				
Commodity sales from production	**70,267**	2,186	**182,668**	9,758
Net marketing income (loss) [1]	**2,854**	-	**6,831**	-
Cash flow from (used in) operating activities	**25,518**	(777)	**35,820**	(1,661)
Adjusted funds flow from (used in) operations [1]	**30,763**	(290)	**69,829**	(1,279)
Per share basic [2,3]	**0.71**	(0.02)	**2.20**	(0.09)
Per share diluted [2,3]	**0.71**	(0.02)	**2.20**	(0.09)
Net debt to adjusted funds flow from operations [1]			**0.74**	N/A
Free funds flow (deficiency) from operations [1]	**(1,195)**	(1,125)	**18,929**	(7,571)
Net income (loss)	**44,306**	9,732	**(22,315)**	(4,869)
Per share basic [2,3]	**1.02**	0.64	**(0.70)**	(0.36)
Per share diluted [2,3]	**1.02**	0.64	**(0.70)**	(0.36)
Capital expenditures prior to acquisitions	**31,958**	835	**50,900**	6,292
Acquisitions	**-**	-	**282,414**	-
Total capital expenditures	**31,958**	835	**333,314**	6,292
Balance sheet ($000s, except share amounts)				
Total assets	**614,337**	172,993	**614,337**	172,993
Long-term liabilities	**124,587**	3,448	**124,587**	3,448
Net debt (surplus) [1]	**51,512**	(54,401)	**51,512**	(54,401)
Adjusted working capital deficit (surplus) [1]	**18,644**	(54,401)	**18,644**	(54,401)
Weighted average shares outstanding [2,3]				
Basic and diluted	**43,622,942**	15,202,845	**31,689,093**	13,540,477
Shares outstanding end of period [2,3]	**43,674,583**	18,723,718	**43,674,583**	18,723,718
Return on average capital employed ("ROACE") [1]			**25%**	(1%)
Reserves				
Proved reserves (MMboe) [4]			**106.1**	30.5
Proved reserves per share (boe) [4]			**2.4**	1.6
Proved plus probable reserves (MMboe) [4]			**180.2**	48.1
Proved plus probable reserves per share (boe) [4]			**4.2**	2.6

1 – 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. See "Non-GAAP Measures" section of this MDA.
2 – As part of the Arrangement, Kiwetinohk consolidated the outstanding Kiwetinohk common shares, stock options and performance warrants on a 10 to 1 basis. This MD&A and all information related to common shares, stock options, performance warrants and per share amounts, have been restated to reflect the share consolidation for all periods presented.
3 – Per share amounts are based on weighted average basic and diluted shares, respectively.
4 – Oil and natural gas reserves are as determined by the Company's independent qualified reserve evaluator with an effective date of December 31 for the years shown in accordance with the Canadian Oil and Gas Evaluation Handbook and are shown as net working interest reserves before royalties.
5 – Realized loss on risk management contracts includes settlement of hedges of physical production and on marketing activity.

Q4 2021 and 2021 Year-End Highlights

- Successfully completed the Simonette Acquisition and amalgamation of Distinction during the year resulting in significantly increased production compared to the prior year.
  - Production volumes averaged 12,422 boe/d and 9,801 boe/d during the quarter and year ended December 31, 2021, respectively.
- During the year, the Company acquired 34.4 million boe of Proved Developed Producing[1] ("PDP") reserves based on updated independent year end reserves estimates, representing a significant increase over 2020 year-end PDP reserves of 0.9 million boe.
  - The additional PDP reserves were acquired for approximately $11.72/boe delivering a strong recycle ratio[2] of 3.5x based on fourth quarter 2021 operating netbacks.
  - The company also increased Proved and Proved plus Probable reserve volumes by 248% and 274% to 106.2 MMboe and 180.2 MMboe, respectively, or reserve volumes per share by 50% and 62% to 2.4 and 4.2 boe per share, respectively.
- Kiwetinohk generated record adjusted funds flow from operations[3] for the quarter and year ended December 31, 2021 of $30.8 million and $69.8 million, respectively, due to successful acquisitions and improved commodity prices.
  - Capital investment activity provided an attractive return on average capital employed[3] for the year of 25% demonstrating the value of the transactions.
- Kiwetinohk filled 100% of its Alliance pipeline capacity of 103.0 MMcf/d (after temporary assignments) during the fourth quarter of 2021 with production and purchased gas volumes.
  - Natural gas marketing activities resulted in realized net marketing income of $2.9 million during the fourth quarter of 2021 and $6.8 million for the year ended December 31, 2021 before settlements of risk management contracts.
- The Company invested $32.0 million and $50.9 million in capital expenditures (excluding acquisitions) for the quarter and year ended December 31, 2021 as it initiated its drilling program in its Fox Creek core area.
  - The expenditures included the drilling and completion expenditures related to two Duvernay wells in the Simonette area and two Montney wells in the Placid area and a vertical test to evaluate the Middle Montney during the fourth quarter of 2021.
- During the year the Company made significant development progress across its 1,800 MW power development portfolio.
  - Kiwetinohk advanced work in the AESO staging process to secure grid access with 4 of 5 projects progressing in Stage 2.
- With stakeholder consultation near completion and a favorable Alberta Environment and Parks ("AEP") referral letter received on March 21, 2022 the Company is targeting an Alberta Utilities Commission ("AUC") submission for the 400 MW Solar 1 project in the second quarter 2022.
- The Company is also targeting to submit AUC and AEP industrial applications for the 101 MW Firm Renewable 1 project in the second quarter 2022.
- On December 13, 2021, the Company's $225.0 million Senior Secured Extendible Revolving Facility ("Credit Facility") was increased to $315.0 million.
  - Available borrowing capacity on the Credit Facility at December 31, 2021 was $228.0 million.

1 Oil and natural gas reserves are as determined by the Company's independent qualified reserve evaluator with an effective date of December 31 for the years shown in accordance with the Canadian Oil and Gas Evaluation Handbook and are shown as net working interest reserves before royalties.

2 Recycle ratio is calculated as operating netback on a per boe basis divided by the costs of acquisitions over estimated PDP reserves. Recycle ratio is used by the Company as a key measure of profitability and the Company's ability to generate cash flows over produced barrels.

3 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. See "Non-GAAP Measures" section of this MDA.

Subsequent events highlights

- On January 14, 2021, Kiwetinohk's common shares commenced trading on the Toronto Stock Exchange under the trading symbol KEC.
- Effective February 3, 2022 the Company appointed two new independent directors Judith Athaide and John Whelen.
- Mr. Timothy Schneider has given notice of his retirement from the Board of Directors effective March 24, 2022 and will not stand for election at the Company's 2022 Annual General Meeting.

Guidance

Kiwetinohk's priority is to deliver attractive returns on capital employed during the year through profitable investment in high quality assets to position the Company to deliver strong free cash flow generation and growth in future years. The Company's annual capital expenditures and production guidance for 2022 remains unchanged and is provided below.

		2022 Guidance	
Operational & financial guidance		**Low**	**High**
Production (2022 average) [1]	**(Mboe/d)**	**13.0**	**15.0**
Oil & liquids	(Mbbl/d)	6.5	7.5
Natural gas	(MMcf/d)	39.0	45.0
Production by market	**(%)**	**100**	**100**
Chicago	**(%)**	87	97
AECO	**(%)**	3	13
Royalty rate (Crown)	**(%)**	12	15
Operating costs[1]	**($/boe)**	7.50	8.50
Transportation (excluding marketing activities)	**($/boe)**	5.00	6.00
G&A expense before share-based compensation [2]	**($MM)**	15.0	18.0
Cash taxes	**($MM)**	-	-
Capital guidance		**Low**	**High**
Capital	**($MM)**	**210**	**240**
Green Energy	**($MM)**	10	20
Upstream	**($MM)**	200	220
New Fox Creek wells (gross)	**(wells)**	**11**	
Duvernay	**(wells)**	10	
Montney	**(wells)**	1	
Sensitivities		**Low**	**High**
Adjusted funds flow from operations[3]			
US$60/bbl WTI & US$3.25/MMBtu HH	**($MM)**	**$120**	**$130**
US$70/bbl WTI & US$3.75/MMBtu HH	**($MM)**	**$145**	**$155**
US$80/bbl WTI & US$4.25/MMBtu HH	**($MM)**	**$165**	**$175**
Net debt to adjusted funds flow from operations[3]			
US$60/bbl WTI & US$3.25/MMBtu HH	**(x)**	**1.3x**	
US$70/bbl WTI & US$3.75/MMBtu HH	**(x)**	**1.0x**	
US$80/bbl WTI & US$4.25/MMBtu HH	**(x)**	**0.7x**	

1 – Production and cash operating costs include a provision for scheduled plant turnarounds at Fox Creek.
2 – Includes all divisions of the Company – Corporate, Upstream, Green Energy (power & hydrogen) and Business Development
3 – 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. See "Non-GAAP Measures" section of this MDA.

The Company continues to make significant progress in advancing its Alberta-based diversified solar and gas-fired development power portfolio and currently expects to spend between $10 and $20 million in 2022 on project planning, approvals, engineering and design and securing of financing required to advance projects to a final investment decision ("FID"). This capital budget is expected to enable the Company to maintain its current schedule of development activities for its existing portfolio of power development projects and also evaluate other early-stage development projects for potential acquisition. The Company expects its first solar and Firm Renewable projects to reach FID by the end of the year and it has provided an updated timeline for its green energy project portfolio as further described in section *Green Energy Development Projects*.

The 2022 upstream capital budget is currently established in a range between $200 to $220 million and is focused the Fox Creek area where the Company plans to drill 11 gross wells. Kiwetinohk expects to bring four wells drilled in late 2021 onto production in the first half of 2022. Six of 11 new wells planned for 2022 are expected to come onto production in the second half of the year, with the remaining five expected to come onto production in the first half of 2023. The capital program is expected to be fully funded from cash flow from operating activities and available debt capacity and is anticipated to deliver strong baseline cash flow in 2022 and thereafter. The wells drilled and completed in 2022 are expected to more than arrest declines, growing production to further fill the Company's facilities at Fox Creek, which are currently operating at less than half of available capacity. The Company has updated its previously communicated first quarter production estimates of 11,000 to 12,000 boe/d to be in line with fourth quarter levels of 12,000 to 13,000 boe/d. The Company still expects production to increase from first quarter of 2022 projected levels to 20,000 to 21,000 boe/d during the first quarter of 2023.

Operating costs are anticipated to be higher in the first half of 2022 impacted by inflationary cost pressure in the field, production declines, cold weather impacts and scheduled plant turnarounds in Fox Creek. With additional production coming onstream through 2022 the Company expects operating costs per boe to improve as increased production volumes fill more of the Company's facilities at Fox Creek and fixed operating costs are spread over a larger production volume.

Acquisitions

The following is a summary of the Company's 2021 Corporate acquisitions:

$000s	Simonette Acquisition	Distinction [1]
Fair value of net identifiable assets acquired		
Property, plant and equipment	345,066	107,042
Working capital [2]	1,726	90,963
Risk management contracts	-	(215)
Asset retirement obligations	(7,105)	(9,488)
Lease liabilities	(605)	(709)
Deferred tax liability	(9,811)	-
	329,271	187,593
Bargain purchase gain	(32,843)	-
	296,428	187,593
Consideration:		
Cash	282,414	-
Distinction deposit on Simonette Acquisition	7,500	-
Investment [3]	-	96,822
Non-controlling interest [4]	-	90,771
Contingent payment consideration	6,514	-
Total purchase price	296,428	187,593

1 – Includes value of Distinction net identifiable assets as at April 28, 2021 immediately prior to the Simonette Acquisition.
2 – Distinction working capital includes $95.8 million of cash acquired.
3 – The investment is comprised of $62.9 million in cash (average cost of $12.91 per share), transaction costs of approximately $2.8 million and an equity gain on investment of $32.6 million and subsequent to the joint Simonette Acquisition Distinction had $63.3 million of debt and working capital of $0.5 million.
4 – Additional shares were issued pursuant to the Arrangement for equity consideration of $101.7 million.

Simonette Acquisition

On April 28, 2021 KRC and Distinction closed an asset acquisition with a purchase price after adjustments of $296.4 million covering certain multi-zone, oil and natural gas properties in the Simonette region (the "Simonette Acquisition"). The purchase price includes the current fair value of up to $15 million of contingent payments if average crude oil prices exceed the reference price for WTI of USD $56.00 per barrel in 2021 and USD $62.00 per barrel in 2022. During January 2022, the Company settled the first contingent payment of $5.0 million.

The Simonette Acquisition is aligned with the Company's strategy of building an energy transition company focused initially on building a risk-diversified, liquids-rich upstream portfolio of Western Canadian oil and gas resource plays.

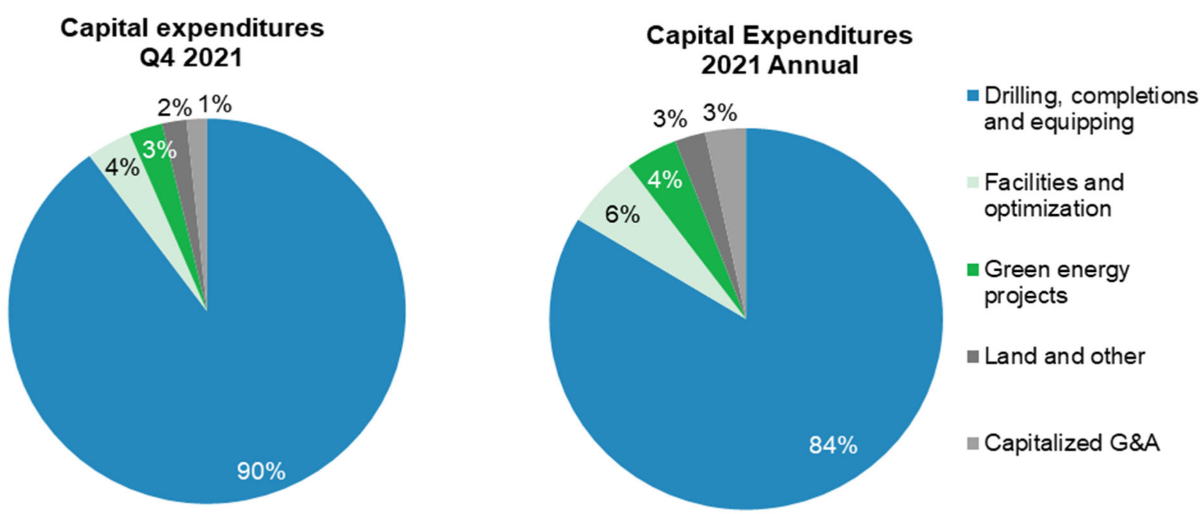
Settlement agreement
Concurrently, with the closing of the Simonette Acquisition, the Company and 1266580 B.C. Ltd., an affiliate of Luminus Energy IE Designated Activity Company ("Luminus Energy"), entered into a settlement agreement to terminate carried interest rights and obligations under a participation agreement made effective by the parties October 16, 2020. A total of $10.0 million of settlement costs were paid to 1266580 B.C. Ltd. as part of the closing procedures of the Simonette Acquisition.

Distinction Amalgamation
On January 15, 2021, the Company increased its previous 25 percent equity interest in Distinction to 51.6 percent through the exercise of warrants for $40.0 million which included working capital adjustments of $2.5 million. During April 2021, Distinction announced the appointment of new KRC executive officers to rebuild Distinction from its prior year CCAA process. The Company gained control of Distinction and began consolidating the results of Distinction on April 28, 2021.

On June 28, 2021, KRC and Distinction announced an agreement to combine under a plan of arrangement pursuant to section 192 of the *Canada Business Corporations Act* (the "Arrangement" or "business combination") with Distinction. Through the Arrangement, KRC acquired all of the shares of Distinction that it did not already own (approximately 48%) by way of an exchange of 20 KRC shares for each Distinction share. Under the Arrangement, Kiwetinohk inherited the reporting issuer status of Distinction. A special meeting of Distinction shareholders and KRC shareholders to vote on the Arrangement was held and approved on August 30, 2021 and the Arrangement closed on September 22, 2021.

Capital expenditures

$000s	Q4 2021	Q4 2020	2021	2020
Drilling, completions and equipping	**28,742**	52	**42,617**	675
Facilities and optimization	**1,184**	-	**3,105**	-
Green energy projects	**867**	-	**2,193**	-
Land and other	**638**	783	**1,280**	5,617
Capitalized G&A	**527**	-	**1,705**	-
Total before acquisitions	**31,958**	835	**50,900**	6,292
Acquisitions (cash consideration)	**-**	-	**282,414**	-
Total capital expenditures	**31,958**	835	**333,314**	6,292



1 – Capital expenditures shown are before Acquisitions.

The majority of the Company's capital expenditures prior to acquisitions were spent on drilling, completions, and equipping.

Drilling

The following is a summary of drilling activity that the Company has recently completed in Alberta:

	Area			Total	
(wells)	Thorhild	Simonette	Placid	Gross	Net
2020	-	-	-	-	-
Q1 2021	-	-	-	-	-
Q2 2021	1.0	-	-	1.0	1.0
Q3 2021	1.0	-	-	1.0	1.0
Q4 2021	-	2.0	3.0	5.0	5.0
Total	2.0	2.0	3.0	7.0	7.0

The Company initiated its drilling program in the Fox Creek area during the fourth quarter with the spudding of 4 wells. Kiwetinohk plans to drill a further 11 wells during 2022. The well designs planned for the program are targeting longer lateral lengths, as well as increased completion volumes and pump rates. The design strategy seeks to reduce capital costs per lateral metre and per barrel of recoverable resources as the wells are expected to access and more effectively stimulate increased reservoir volumes. As Kiwetinohk has recently initiated its first drilling program following the completion of major corporate transactions, management expects to incur incremental capital costs as new well designs are tested and new learnings are incorporated over the course of the drilling program. Improved capital efficiencies are anticipated over the course of the program and into subsequent years as cost efficiencies are realized and well performance from enhanced well designs is optimized.

During the fourth quarter of 2021, the Company rig released two Duvernay horizontal wells from the existing 9-07 pad in the Simonette area. One well came on stream at the end of February and is currently producing approximately 3.0-3.5 MMcf/d of natural gas and liquids and approximately 800-900 bbls/d of condensate. The early-stage practice is to bring these wells on stream slowly by keeping the well choked back. The Company is very encouraged by the early performance of this well. A second well completed at the same time encountered some difficulties while milling out the plugs from the fracture stimulation operation. The operation is currently attempting to recover tubing and the milling bit from the well prior to bringing this well online, and the Company is targeting to start production from this well early in the second quarter of 2022. Drilling costs for the two wells averaged just over $6.5 million per well. Completion costs for the first well that is currently on production is expected to come in between $9-10 million. The second well, where the problems have occurred, is expected to see significant cost overruns due to the complications encountered. It is expected that these costs will be lower on subsequent wells, which has already been seen on more recent activity.

The Company also drilled two Placid-area wells in the Montney formation. Completion operations finished in mid-March 2022 and the flow back operation recently commenced through test facilities, with initial well results expected in April 2022. Drilling costs for the two wells averaged just over $4 million per well. Completion costs for these two wells is expected to average $5.5 million per well.

In early 2022, the Company drilled two Duvernay horizontal wells on pad 12-28 in the northern part of the Simonette area that are currently waiting to be completed and brought on-line. Drilling costs for these two wells averaged just under $5 million per well. In addition, the Company is drilling four Duvernay horizontal wells on pad 4-34 also in the Simonette area, which will be completed and brought on-line in the second half of 2022.

Equip and tie-in costs across the development program are expected to average approximately $1 million per well.

Green Energy Development Projects

The Company is advancing its plan to secure and develop renewable and natural gas-fired power generation projects as part of its broader strategy to create an integrated low emissions energy platform. It is actively pursuing the development of a number of greenfield projects which are at various stages of the development cycle. Kiwetinohk is also evaluating acquisitions of certain early-stage power projects, generally renewables, which have been under development by other parties.

Development work to date has included, among other things, preparation of preliminary designs, acquisition of surface land lease options, preparation of environmental studies, application for permits, stakeholder consultation, AESO stage reviews and studies and preparation of performance and preliminary cost estimates. This work is part of a staged process to prudently advance project development and manage the risks of project execution. For those projects that continue to meet the Company's investment criteria through earlier stages of development, the intent will be to proceed towards a FID while continuing to finalize design and cost estimates, pursue final regulatory approvals and secure internal and external funding.

The Company commences capitalization of development costs after it becomes highly probable that it will be an economic success and otherwise meets the Company's investment criteria. Prior to that, all development costs are expensed as G&A costs.

Kiwetinohk's near term power generation strategy is currently focused on three pillars:

- utility scale solar and/or wind power;
- Firm Renewable; and
- large-scale, baseload natural gas combined cycle power ("NGCC")

Solar Projects:
Kiwetinohk's is advancing two projects through early-stage development, engineering, permitting, and the regulatory approval process. The company's Solar 1 project is most advanced and is targeted to achieve FID by year end subject to obtaining regulatory approvals and financing.

Firm Renewable Projects:
The term "Firm Renewable" is a Kiwetinohk-originated term that describes efficient, flexible-output, fast-responding, gas-fired, internal reciprocating engine-drive power generation that address the need for stability that has been revealed as wind and solar renewable power grows to become a more significant proportion of a grid's power supply. The Company's most advanced gas-fired power project is a Firm Renewable project. The FEED work is complete and cost estimates are nearing completion in consultation with an engineering, procurement and construction management firm that has been engaged to develop a turnkey proposal to supply and construct the project.

The Company's Firm Renewable 1 project is targeted to achieve FID by year end subject to regulatory approvals and financing. The Company has revised its target FID for Firm Renewable 1 from Q3 to Q4 2022 to account for potential regulatory delays and increased its installed cost estimate by $11 million to $156 million based on potential increases in material and equipment costs and supply chain challenges in a post pandemic environment.

NGCC Projects:
Kiwetinohk is in the early stages of planning two NGCC power plants and is advancing pre-FEED work and AESO stage reviews and studies. The Company has assessed potential for delays in regulatory approvals, carbon capture, utilization and storage ("CCUS") policies and programs, and supply chain challenges in a post pandemic environment. As a result, the Company has delayed its indicative FID and COD for NGCC 2 to Q4 2023 and Q4 2026, respectively.

Early-stage development and design factors and the status of each project are summarized in the following tables:

	Solar 1	Solar 2	Firm Renewable 1	NGCC 1	NGCC 2
Nameplate/Net to Grid Capacity	400 MW	300 MW	101 MW 97 MW	500 MW 460 MW	500MW 460 MW
AESO Stage	2	1	2	2	2
Site Control	Options secured	Options secured	Land acquisition in progress	Options secured	Land acquisition in progress
Public Consultation	Underway	Planning underway	Completed	Planning underway	Planning underway
Regulatory / Environmental	AEP referral letter received; AUC Q2 2022	AEP application submitted	AUC and AEP Q2 2022	Planning underway	Planning underway
Engineering	Pre-FEED complete; FEED near completion	BD complete	FEED complete	BD complete; Pre-FEED underway	BD complete; Pre-FEED underway
Targeted FID	Q3 2022	Q2 2023	Q4 2022	Q3 2024	Q4 2023
Targeted COD [1]	Q4 2024	Q2 2025	Q4 2024	Q3 2027	Q4 2026
Total installed capital cost ($ million) [2, 3, 4]	$655 (Class 3)	$492 (Class 3)	$156 (Class 3)	$875 (Class 4)	$875 (Class 4)

1 – If a FID decision is reached the Company will advance the project towards an estimated Commercial Operations Date ("COD").
2 – Total installed cost estimates are classified in a manner consistent with American Association of Cost Engineering (AACE) standards.
3 – Total installed cost numbers exclude carbon capture and sequestration. CCUS costs are estimated to be 60 to 80% of the total installed cost.
4 – None of the Company's planned power generation projects have a final design, performance projection or cost estimate, or full regulatory approval or internal or external funding. There is no assurance that the power generation projects will proceed as described or at all.

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

Financing Strategy	Strategy Description
Carried equity interest	Earn a carried equity interest in the construction and operations of a project in exchange for the risk and costs incurred to bring it to FID. No further equity capital would be required by the Company post FID.
Carried equity interest and co-invest	Earn a carried equity interest for bringing a project to FID and co-invest with third party investors at the project FID stage to further increase the Company's working interest in the project.
Carried equity interest with natural gas commitment	Earn a carried equity interest for bringing a project to FID and earn additional carried equity interest in exchange for a multi-year commitment of natural gas to a project at market or negotiated prices.
Strategic partnership	Enter into a strategic partnership with a party or parties to invest across the Company's entire power portfolio. The Company may also look to access other financial supports, including Indigenous financing sources and export credit agency funding and guarantees.

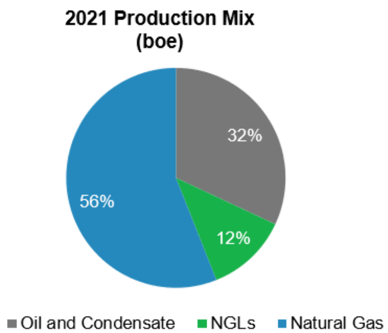
	Kiwetinohk also intends to apply for grants in areas of interest, such as CCUS, as appropriate.
Full development and subsequent sell down	The Company would fund the construction of a power project, which may include participation of external investment counterparties, and sell down a significant working interest at commercial operation date (COD).

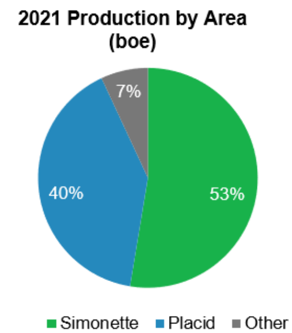
Kiwetinohk believes successful execution of its investment and financing strategies for its power project portfolio will allow it to achieve an attractive rate of return above its current cost of capital while providing material ownership interest and operational control of its downstream assets.

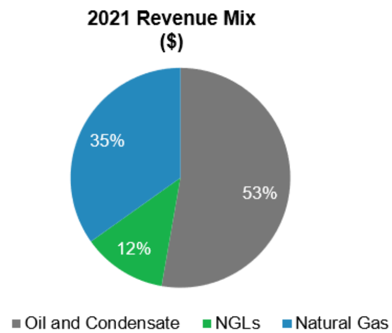
Results of operations

Production

	Q4 2021	Q4 2020	2021	2020
Condensate (bbl/d)	**3,092**	13	**2,644**	35
Light oil (bbl/d)	**844**	374	**457**	429
Heavy oil (bbl/d)	**13**	43	**29**	15
NGLs (bbl/d)	**1,572**	41	**1,180**	64
Natural gas (Mcf/d)	**41,410**	1,045	**32,942**	1,367
Total production (boe/d)	**12,442**	645	**9,801**	771
Oil and condensate % of production	**32%**	67%	**32%**	62%
NGL % of production	**13%**	6%	**12%**	8%
Natural gas % of production	**55%**	27%	**56%**	30%
Total production volumes %	**100%**	100%	**100%**	100%







Production during the fourth quarter of 2021 averaged 12,442 boe/d and 9,801 boe/d for the year ended December 31, 2021. The Company's production volumes increased significantly with the closing of the Simonette Acquisition and consolidation of Distinction operating results commencing on April 28, 2021. The Company's production portfolio during 2021 was 32% oil and condensate, 12% NGLs, and 56% natural gas, with the largest shifts in production seen in natural gas as compared to prior year.

The Simonette Acquisition contributed on average 6,742 boe/d and 5,223 boe/d during the three and twelve months ended December 31, 2021 while Distinction contributed an average of 5,200 boe/d and 3,964 boe/d. The Simonette and Distinction assets both deliver high liquids content natural gas with the Company now having an average liquid yield of approximately 133 bbls/MMcf.

Benchmark and realized prices

	Q4 2021	Q4 2020	2021	2020
Liquid benchmark prices				
WTI (US$/bbl)	**77.19**	42.75	**67.91**	39.44
WTI (CDN$/bbl)	**97.20**	55.53	**85.13**	52.53
Edmonton Light (CDN$/bbl)	**92.14**	50.12	**80.28**	45.28
WCS Hardisty (CDN$/bbl)	**78.82**	43.58	**68.80**	35.56
Natural gas benchmark prices				
Henry Hub (US$/MMBtu)	**5.83**	2.77	**3.84**	2.13
Chicago City Gate MI (US$/MMBtu)	**5.87**	2.49	**3.77**	1.98
Chicago City Gate DI (US$/MMBtu)	**4.59**	2.31	**5.19**	1.88
AECO 5A (CDN$/GJ)	**4.41**	2.50	**3.44**	2.11
AECO 7A (CDN$/GJ)	**4.69**	2.62	**3.38**	2.12
Alberta Power				
Daily (CDN$/MWh)	**107.33**	46.13	**101.93**	46.72
Daily on Peak (CDN$/MWh)	**121.13**	52.45	**122.61**	54.72
Foreign exchange rates (CAD/USD)	**0.79**	0.76	**0.80**	0.75

	Q4 2021	Q4 2020	2021	2020
Realized prices				
Condensate ($/bbl)	**99.21**	55.56	**84.94**	55.47
Light oil ($/bbl)	**92.29**	48.57	**82.46**	48.13
Heavy oil ($/bbl)	**81.60**	35.58	**59.22**	34.40
NGLs ($/bbl)	**65.61**	14.04	**52.60**	7.09
Natural gas ($/Mcf)	**6.64**	2.66	**5.29**	2.28
Total ($/boe)	**61.48**	36.83	**51.06**	34.60

WTI benchmark prices are higher in the quarter and year ended December 31, 2021 compared to the same periods in 2020. The increase is primarily due to decreased global investment in oil production, the global economic recovery, the return of energy demand as jurisdictions around the world opened-up following the easing of restrictions related to the COVID-19 pandemic, as well as restricted supply from the Organization of Petroleum Exporting Countries ("OPEC") and Russia. This, along with increased capital discipline amongst producers has resulted in global crude oil demand outpacing supply during 2021.

Similar to WTI, Edmonton Light benchmark pricing experienced increases in 2021 compared to 2020. For the three and twelve months ended December 31, 2021, Edmonton Light benchmark prices averaged $92.14 per barrel and $80.28 per barrel compared to $50.12 per barrel and $45.28 per barrel in 2020, respectively.

Natural gas prices increased in 2021 due to low storage levels, a decrease in supply due to lower investment and an increase in US natural gas exports all of which have continued to drive an increase in year over year demand and pricing. The Chicago City Gate monthly index benchmark for natural gas for the three and twelve months ended December 31, 2021 increased to US $5.87/MMBtu and US $3.77/MMBtu, representing an increase in pricing of 135% and 90%, respectively. The Chicago City Gate daily index benchmark for natural gas for the three and twelve months ended December 31, 2021 increased 99% and 176% percent, respectively in comparison to the same periods in 2020.

The Alberta provincial power price increased by 132% and 118% during the quarter and year ended December 31, 2021. This was a result of expiring Alberta Power Purchase Agreements, higher natural gas prices and an overall demand recovery along with planned maintenance outages in Alberta.

The Company has a total of 120 MMcf/d of firm Alliance Pipeline transportation service to Chicago contracted through October 31, 2025 that was acquired from both the Simonette and Distinction transactions. This allows the Company to benefit from an agreement with Aux Sable whereby liquids contained within the natural gas are extracted, fractionated and sold into the US Midwest refining and petrochemical market, and the remaining natural gas sold into the Chicago area marketplace and interconnecting markets. Prior to the completion of the Arrangement, Kiwetinohk purchased Distinction's natural gas volumes from Simonette at the plant gate and then sold total Simonette natural gas volumes in Chicago.

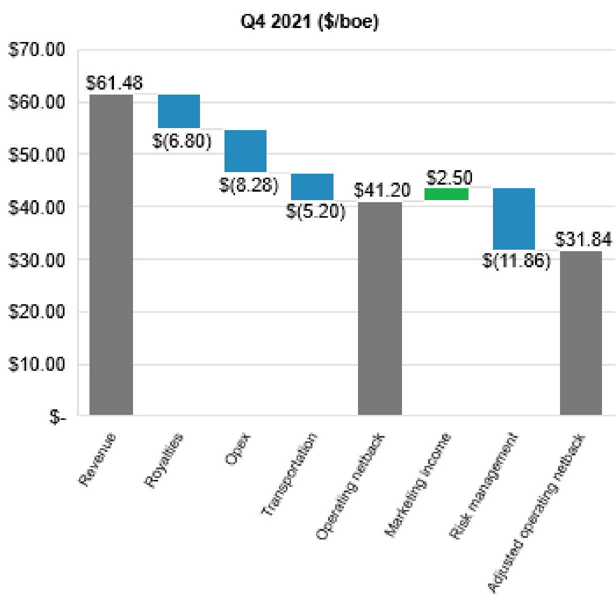
Kiwetinohk also sells natural gas in the AECO market through the Nova Gas Transmission Ltd. ("NGTL") system. Natural gas that is sweetened (through the removal of Hydrogen Sulfide) at the Company's amine facility is further processed at its 25 percent owned sweet natural gas plant ("Bigstone Sweet Plant") which is currently connected to the NGTL pipeline system. The Alliance meter station at the Bigstone Sweet Plant is expected to be reactivated in the second quarter of 2022 which will allow the Company to transport its natural gas on both the NGTL and Alliance pipeline systems.

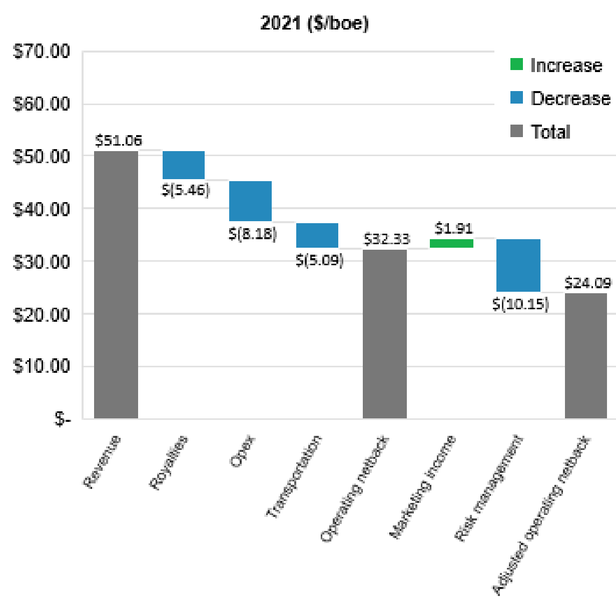
The Company has contracted for 0.3 MMcf/d of transportation service on NGTL which expires in mid-2023, and a separate and independent NGTL contract for approximately 20.2 MMcf/d expiring on March 31, 2026.

Operating netback

	Q4 2021	Q4 2020	2021	2020
Realized price ($/boe)	**61.48**	36.83	**51.06**	34.60
Royalty recovery (expense) ($/boe)	**(6.80)**	1.57	**(5.46)**	(2.14)
Operating expenses ($/boe)	**(8.28)**	(9.94)	**(8.18)**	(9.66)
Transportation expenses ($/boe)	**(5.20)**	(1.06)	**(5.09)**	(0.80)
Operating netback[1]($/boe)	**41.20**	27.40	**32.33**	22.00
Marketing income ($/boe)	**2.50**		**1.91**	
Realized loss on risk management contracts ($/boe)	**(11.86)**	-	**(10.15)**	-
Adjusted operating netback [1]	**31.84**	27.40	**24.09**	22.00
Total production (boe/d)	**12,422**	645	**9,801**	771

1 – 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. See "Non-GAAP Measures" section of this MD&A.





Operating netback during the quarter ended December 31, 2021 was $41.20/boe compared to $27.40/boe in the same period in the prior year primarily driven by a 67% increase in average realized pricing. The increase in realized pricing was offset by higher royalty expenses of $6.80/boe during the current period quarter versus a recovery of $1.57/boe in the same period prior year due to a crown royalty reclassification on one well that resulted in a refund. Additionally, with significant gas production being shipped to Chicago as a result of the Simonette and Distinction acquisitions, the Company's transportation expense increased from $1.06/boe to $5.20/boe. Operating netback increased by 47% during the year ended December 31, 2021 as compared to the year ended December 31, 2020 for similar reasons as noted above.

Adjusted operating netback was $31.84 boe/d for the quarter ended December 31, 2021 and $24.09 boe/d for the year ended December 31, 2021 a 16% and 10% increase compared to the same periods in prior year, respectively. The Company incurred a realized loss on risk management contracts of $11.86/boe and $10.15/boe for the three and twelve months ended December 31, 2021.

Revenue

$000s	Q4 2021	Q4 2020	2021	2020
Condensate	**28,218**	66	**81,978**	708
Light oil	**7,166**	1,669	**13,770**	7,557
Heavy oil	**97**	142	**619**	186
NGLs	**9,488**	53	**22,659**	166
Natural gas	**25,298**	256	**63,642**	1,141
Total commodity sales from production	**70,267**	2,186	**182,668**	9,758

Revenues increased to $70.3 million and $182.7 million for the quarter and year ended December 31, 2021, an increase of $68.1 million and $172.9 million from the same periods in the prior year. The increase was primarily as a result of higher pricing and the Simonette and Distinction acquisitions which contributed to greater volumes over the same periods in prior year.

Risk management contracts

In an effort to mitigate commodity price fluctuations for natural gas, crude oil and natural gas liquids, the Company enters into financial commodity contracts as part of its risk management program designed to protect cash flows from its base production and help ensure sufficient capital and liquidity is available to pursue its ongoing growth plans. Risk management contracts are entered into at prices that enhance the probability of capital projects meeting or exceeding their targeted financial return hurdles. All risk management contracts are entered into according to the Company's risk management policy, ensuring the Company retains its ability to cover all outstanding risk management liabilities when they arise. Additionally, the Company regularly reviews its credit exposure to financial counterparties that volumes are purchased from or sold to.

		Q4 2021	Q4 2020	2021	2020
Unrealized gain (loss) on risk management contracts		**33,916**	-	**(28,588)**	-
Realized gain (loss) on risk management contracts		**(13,547)**	-	**(36,306)**	-
Total gain (loss) on risk management contracts		**20,369**	-	**(64,894)**	-
Unrealized gain (loss)	**$/boe**	**29.68**	-	**(7.99)**	-
Realized gain (loss)	**$/boe**	**(11.86)**	-	**(10.15)**	-

For the three and twelve months ended December 31, 2021, the Company recorded realized losses on risk management contracts of $13.5 million and $36.3 million, respectively. The unrealized gain on risk management contracts of $33.9 million and unrealized loss of risk management contracts of $28.6 million for the three and twelve months ended December 31, 2021 respectively, represents changes in the fair value of risk management contracts during those periods.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its natural gas and crude oil financial contracts on the balance sheet at each reporting period with the change in the fair value being classified as unrealized gains and losses in the consolidated statement of net loss and comprehensive loss.

The fair values of these contracts are based on an approximation of the amounts that would have been paid to or received from counterparties to settle the contracts outstanding at the end of the period having regard to forward prices and market values provided by independent sources. Due to the inherent volatility in commodity prices, foreign exchange and interest rates, actual amounts realized may differ from these estimates.

The Company has the following risk management contracts outstanding as of December 31, 2021:

Type	Unit	Q1 2022	Q2 2022	Q3 2022	Q4 2022	2023
Crude oil						
WTI fixed price	bbl/d	750	750	750	750	900
WTI buy put	bbl/d	2,367	2,167	2,033	1,883	-
WTI sell call	bbl/d	2,367	2,167	2,033	1,883	-
WTI swap average	CDN$/bbl	$69.950	$69.950	$69.950	$69.950	$82.600
WTI buy put average	CDN$/bbl	$65.000	$65.000	$65.000	$65.000	-
WTI sell call average	CDN$/bbl	$76.715	$76.692	$76.668	$76.650	-
Natural gas [2]						
NYMEX Henry Hub fixed price	MMBtu/d	18,900	21,167	20,350	15,350	11,375
NYMEX Henry Hub buy put	MMBtu/d	2,500	2,500	2,500	2,500	2,000
NYMEX Henry Hub sell call	MMBtu/d	2,500	2,500	2,500	2,500	2,000
NGI Chicago basis to NYMEX Henry Hub	MMBtu/d	17,400	19,600	18,450	17,950	9,375
NYMEX Henry Hub fixed price average	US$/MMBtu	$2.806	$2.986	$2.979	$2.697	$3.353
NYMEX Henry Hub buy put average	US$/MMBtu	$3.000	$3.000	$3.000	$3.000	$3.000
NYMEX Henry Hub sell call average	US$/MMBtu	$4.750	$4.750	$4.750	$4.750	$3.805
NGI Chicago basis to NYMEX Henry Hub average	US$/MMBtu	$0.194	($0.145)	($0.170)	($0.064)	$0.007
AECO 5A fixed price	GJ/d	2,250	2,250	2,025	2,025	-
AECO 5A average	CDN$/GJ	$2.262	$2.262	$2.092	$2.092	-
Natural gas transportation [2,3]						
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	80,000	30,000	30,000	10,000	-
Sell GDD Chicago basis (to NYMEX Henry Hub)	MMBtu/d	(80,000)	(30,000)	(30,000)	(10,000)	-
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	($0.971)	($1.335)	($1.335)	($1.335)	-
GDD Chicago basis (to NYMEX Henry Hub) average)	US$/MMBtu	$0.200	$0.052	$0.052	$0.052	-
Foreign exchange						
Sell USD CAD (monthly average)	US$	$10.0 MM	$5.0 MM	$5.0 MM	$1.7 MM	-
USD/CAD rate		1.2902	1.2901	1.2901	1.2901	-

1 – Prices per unit and volumes per day are represented at the average amounts for the period.
2 – All basis swap pricing is in $USD/unit relative to NYMEX Henry Hub benchmark pricing.
3 – Natural gas transportation hedges relate to basis pricing differentials between AECO and Chicago on firm transportation commitments.

The Company's total risk management contract liability outstanding as at December 31, 2021 and 2020 is as follows:

$ 000's	2021	2021
Short term risk management contracts	**26,115**	-
Long term risk management contracts	**2,688**	-
Total risk management contracts liability	**28,803**	-

Subsequent to December 31, 2021, the Company entered into the following risk management contracts:

Type	Unit	2022	2023	2024
Crude oil				
WTI fixed price	bbl/d	-	275	500
WTI swap average	CDN$/bbl	-	$70.410	$70.620
Natural gas [2]				
NYMEX Henry Hub fixed price	MMBtu/d	-	-	2,500
NYMEX Henry Hub buy put	MMBtu/d	3,000	-	-
NYMEX Henry Hub sell call	MMBtu/d	3,000	-	-
NYMEX Henry Hub fixed price average	US$/MMBtu	-	-	$3.233
NYMEX Henry Hub buy put average	US$/MMBtu	$4.45	-	-
NYMEX Henry Hub sell call average	US$/MMBtu	$5.125	-	-
Natural gas transportation [2,3]				
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	29,167	-	-
Sell GDD Chicago basis (to NYMEX Henry Hub)	MMBtu/d	(29,167)	-	-
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	($1.199)	-	-
GDD Chicago basis (to NYMEX Henry Hub) average)	US$/MMBtu	($0.226)	-	-
Foreign exchange				
Buy USD CAD put (monthly average)	US$	$2.9 MM	-	-
Sell USD CAD call (monthly average)	US$	$2.9 MM	-	-
Buy USD/CAD put rate		1.2527	-	-
Sell USD/CAD call rate		1.3000	-	-

1 – Prices per unit and volumes per day are represented at the average amounts for the period.
2 – All basis swap pricing is in $USD/unit relative to NYMEX Henry Hub benchmark pricing.
3 – Natural gas transportation hedges relate to basis pricing differentials between AECO and Chicago on firm transportation commitments.

Marketing income (loss)

$000s	Q4 2021	Q4 2020	2021	2020
Marketing revenue	**58,398**	-	**114,517**	-
Marketing expense (loss)	**(55,544)**	-	**(107,686)**	-
Net marketing income (loss) [1]	**2,854**	-	**6,831**	-
$/boe	**2.50**	-	**1.91**	-

1 – 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. See "Non-GAAP Measures" section of this MDA.

In order to mitigate the cost of transportation service in excess of its needs, the Company purchases available natural gas volumes in Alberta and/or British Columbia and resells these volumes in Chicago. The Company was able to successfully purchase and fill the balance of the Alliance firm transportation commitment during the quarter after corporate field production and temporarily assigned volumes. The Company also enters into risk management contracts associated with marketing activities to protect the basis differential between the Alberta and Chicago sales points on the pipeline including related foreign exchange contracts.

In the three and twelve months ended December 31, 2021, the Company realized net marketing income of $2.9 million and $6.8 million, respectively on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system. The Company has natural gas production which used approximately 24% of the firm transportation commitment during the fourth quarter of 2021. Profitable arbitrage between the Chicago and AECO benchmark prices was partially offset by losses on temporary assignments of capacity by other parties.

Royalty expense

$000s	Q4 2021	Q4 2020	2021	2020
Royalty expense (recovery)	**7,766**	(93)	**19,526**	604
As a % of revenue	**11%**	(4%)	**11%**	6%
$/boe	**6.80**	(1.57)	**5.46**	2.14

The Company pays crown, freehold, and overriding royalties on production volumes. Royalties in the fourth quarter of 2021 increased to $7.8 million relative to a recovery of $0.1 million in the same period in prior year. Royalties increased from 6% as a percentage of revenues for the full year 2020 to 11% in the current year. The increase is primarily a result of higher pricing and additional royalties attributed to the Simonette and Distinction acquisitions.

Some Distinction wells are burdened with higher Crown rates under an older royalty regime. Under the old royalty regime, when a well comes off of a royalty holiday, the Crown royalty rate for field condensate and natural gas liquids can increase up to an average of approximately 40 percent (depending on individual well factors and benchmark prices).

Production from wells drilled subsequent to January 1, 2017 qualify for reduced Crown royalty rates under the Modern Royalty Framework which currently imposes a five percent royalty rate until certain conditions are met. The Company is able to further benefit from gas cost allowance (crown royalty credits) based in part on the amortization of historical capital and operating costs incurred in the gathering and processing of the Crown's share of natural gas production.

Operating expenses

$000s	Q4 2021	Q4 2020	2021	2020
Operating expenses	**9,460**	590	**29,272**	2,722
$/boe	**8.28**	9.94	**8.18**	9.66

Operating costs include amounts incurred to extract commodities to the surface such as field operators, gas and liquids processing, gathering and compression, utilities, chemicals and maintenance related costs. Operating costs increased significantly in the quarter and year ended December 31, 2021 compared to prior year as production volumes increased by 11,797 boe/day and 9,030 boe/day, respectively from the Simonette and Distinction acquisitions.

On a per boe basis, operating costs decreased from $9.94/boe and $9.66/boe during the three and twelve months ended December 31, 2020 to $8.28/boe to $8.18 in the current year periods due to the new asset cost profile and comparable cost savings associated with 100% owned and operated infrastructure in the Simonette property. During the fourth quarter of 2021, the Company incurred higher operating expenses due to a combination of inflationary cost pressures, seasonality and cold weather and workovers.

Transportation expenses

$000s	Q4 2021	Q4 2020	2021	2020
Transportation expenses	**5,939**	63	**18,193**	226
$/boe	**5.20**	1.06	**5.09**	0.80

Transportation expenses are incurred to deliver oil and natural gas commodities from the Company's production to the delivery point of sale. Prior to the Simonette Acquisition and Distinction business combination the Company did not have any significant transportation costs. The Company now has firm transportation service on the Alliance pipeline system from Alberta to Chicago. The balance of costs pertains to trucking charges and pipeline fees related to oil, NGL and condensate transportation charges.

Adjusted funds flow from (used in) operations

$000s	Q4 2021	Q4 2020	2021	2020
Cash flow from (used in) operating activities	**25,518**	(777)	**35,820**	(1,661)
Net change in non-cash working capital from operating activities	**2,168**	487	**11,977**	382
Asset retirement obligation expenditures	**671**	-	**671**	-
Restructuring costs	**9**	-	**2,458**	-
Acquisition costs	**2,397**	-	**8,903**	-
Settlement costs	**-**	-	**10,000**	-
Adjusted funds flow from (used in) operations [1]	**30,763**	(290)	**69,829**	(1,279)
$/boe	**26.92**	(4.89)	**19.52**	(4.53)

1 – 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. See "Non-GAAP Measures" section of this MD&A.

Adjusted funds from operations increased to $30.8 million and $69.8 million, respectively for the three and twelve months ended December 31, 2021 as a result of the Simonette and Distinction acquisitions. The Company's cash flow from operating activities was $25.5 million and $35.8 million for the three and twelve months ended December 31, 2021. Cash flow from (used in) operating activities has been adjusted for the net change in non-cash working capital from operating activities, restructuring costs associated with Distinction's CCAA process, acquisition costs to complete the Simonette and Distinction acquisitions and $10.0 million in one-time settlement costs to terminate certain carried interest rights and obligations *(see section – Settlement agreement).*

Free funds flow (deficiency) from operations

$000s	Q4 2021	Q4 2020	2021	2020
Adjusted funds flow from (used in) operations	**30,763**	(290)	**69,829**	(1,279)
Capital expenditures (excluding acquisitions)	**(31,958)**	(835)	**(50,900)**	(6,292)
Free funds flow (deficiency) from operations [1]	**(1,195)**	(1,125)	**18,929**	(7,571)
$/boe	**(1.05)**	(18.95)	**5.29**	(26.84)

1 – 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. See "Non-GAAP Measures" section of this MD&A.

Free funds flow (deficiency) from operations during the quarter ended December 31, 2021 was $1.2 million relative to $1.1 million used in the prior year quarter. The Company had higher capital expenditures during late December due to drilling and completions activity. Free funds flow from operations increased to $18.9 million year to date December 31, 2021, a $26.5 million increase over prior year as adjusted funds flow from operations increased by $71.1 million offset by increased capital expenditures of $44.6 million year over year as the Company continues to develop the Fox Creek core area.

Return on average capital employed ("ROACE")

$000s	2021	2020
Adjusted funds flow from (used in) operations	**69,829**	(1,279)
Average capital employed	**280,400**	97,111
ROACE (Adjusted funds flow from (used in) operations/Average capital employed) [1]	**25%**	(1%)

1 – 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. See "Non-GAAP Measures" section of this MD&A.

ROACE increased to 25% during the twelve months ended December 31, 2021. Adjusted funds flow from operations increased by $71.1 million relative to the prior year due to an increase in production from the Simonette and Distinction acquisitions. Average capital employed increased by $183.4 million as the Company fully drew on its equity line of credit during 2021 and acquired 10.2 million common shares of Distinction. In addition, the Company had loans and borrowings outstanding of $32.9 million as at December 31, 2021 whereas the Company had no debt outstanding at December 31, 2020.

Share in earnings of associate

$000s	Q4 2021	Q4 2020	2021	2020
Share in earnings / excess fair value of associate	-	12,878	**19,618**	12,878

The Company had a 51.6 percent ownership interest in Distinction prior to April 28, 2021 and accounted for its investment under the equity method. As of April 28, 2021, the Company obtained control over Distinction and began to consolidate the results of Distinction. The Company recognized $19.6 million of share in earnings and fair value adjustments in the consolidated statement of net loss and comprehensive loss through April 28, 2021. The Company recognized earnings of $12.9 million during the twelve months ended December 31, 2020 reflecting the Company's 25 percent equity investment subsequent to the October 16, 2020 investment.

General and administrative ("G&A") expenses

$000s	Q4 2021	Q4 2020	2021	2020
Gross G&A expenses	**5,589**	1,689	**14,381**	5,628
Capitalized G&A	**(527)**	-	**(1,705)**	-
G&A expenses	**5,062**	1,689	**12,676**	5,628
$/boe	**4.43**	28.46	**3.54**	19.95

G&A expenses increased by $3.4 million and $7.0 million during the quarter and year ended December 31, 2021 as compared to the same periods in prior year. The increases are primarily attributable to the significant growth in the Company that occurred in 2021. This included additional employees to support and execute on the Company's strategy, a discretionary bonus for 2021 performance, professional fees to support the business, preparation for the TSX listing and costs related to a transition to a public company which required additional resources. A portion of G&A activity continues to be directly related to business development initiatives in the Green Energy segment consistent with Kiwetinohk's strategy to capture a larger portion of the hydrocarbons value chain by securing access to downstream power, petrochemicals, and LNG/LPG markets.

G&A expense was reduced by $0.5 million and $1.7 million, respectively for direct and incremental G&A costs for upstream and green energy projects that were capitalized during the quarter and year ended December 31, 2021.

Share-based compensation expenses

$000s	Q4 2021	Q4 2020	2021	2020
Share-based compensation expenses	**4,316**	503	**14,472**	2,121
$/boe	**3.78**	8.48	**4.05**	7.52

Share-based compensation is the non-cash compensation expense recognized for stock options, performance warrants and capital warrants. The expense is based on an estimated grant date fair value of the stock options and warrants, recognized over a graded vesting period by tranche, which results in a higher upfront expense recorded in the earlier years of the vesting periods.

Share-based compensation was $4.3 million and $14.5 million for the three and twelve months ended December 31, 2021 as compared to $0.5 million and $2.1 million in the comparable prior year periods. Adjusting for the 10:1 share consolidation, the Company granted 1.4 million options and 5.5 million performance warrants during the twelve months ended December 31, 2021 and also assumed 0.6 million Distinction options which were fully vested.

Finance costs

$000s	Q4 2021	Q4 2020	2021	2020
Accretion	**442**	5	**654**	17
Interest and bank charges	**1,470**	-	**2,959**	-
Interest on lease obligations	**20**	14	**71**	67
Deferred financing amortization	**231**	-	**901**	-
Total finance costs	**2,162**	19	**4,585**	84
$/boe	**1.89**	0.32	**1.28**	0.30

On April 28, 2021 both KRC and Distinction entered into a combined $225.0 million Senior Secured Extendible Revolving Facility and made a combined initial draw of $126.3 million to fund the Simonette Acquisition. The Company's loans and borrowing balance at the end of December 31, 2021 was $32.9 million. See *Section – Loans and Borrowings.*

Depreciation

$000s	Q4 2021	Q4 2020	2021	2020
Depreciation	**296**	111	**1,139**	473
Depletion	**11,846**	-	**29,064**	-
Total depreciation	**12,142**	111	**30,203**	473
$/boe	**10.62**	1.86	**8.44**	1.68

The Company's depletable base increased with current period acquisition activity. The Simonette and Distinction properties at acquisition date had property, plant, and equipment fair values of $345.1 and $107.0 million, respectively. The acquisitions and higher capital expenditures and production during 2021 resulted in depletion of $11.8 million and $29.1 million for the quarter and year ended December 31, 2021.

Exploration and evaluation ("E&E") expenses

$000s	Q4 2021	Q4 2020	2021	2020
Depletion	**881**	2,224	**5,428**	13,674
Impairment	**-**	-	**47,415**	-
Other	**269**	671	**3,395**	2,685
Total E&E expenses	**1,150**	2,895	**56,238**	16,359
$/boe	**1.01**	48.78	**15.72**	58.01

The Company continuously evaluates various projects and upstream business opportunities, which are expensed as incurred until the Company has purchased the related land and has a legal right to explore. The Company will engage various consultants, advisors, and reservoir engineering specialists in completing evaluation and due diligence procedures.

E&E depletion expense is recorded on a unit of production basis for properties that have production but have not yet been transferred to property plant and equipment. The decrease in depletion in 2021 is a result of production declines and a lower E&E depletable base.

With the Simonette Acquisition and associated lands acquired, the Company re-prioritized its development and drilling plans in the first quarter of 2021 to higher-return undeveloped land locations. This is anticipated to result in some near-term land expiries whereby a portion of the E&E assets for existing wells and undeveloped land may not be recoverable, resulting in an impairment charge of $46.0 million in the first quarter of 2021. Additionally, the Company recognized $1.4 million in E&E impairment expense during 2021 for well costs incurred on a new drill in the Clearwater play which may not be fully recoverable based on well performance to date.

Income taxes

The Company did not pay any income taxes in 2021 and does not expect to be taxable in the near future. The Company initially recognized a deferred tax liability of $9.8 million on the Simonette Acquisition where tax pools acquired were less than the fair value accounting basis. This was subsequently recovered through the consolidated statement of net loss and comprehensive loss as the Company has sufficient tax pools. However, a deferred tax asset has not been recognized at December 31, 2021 given uncertainty around future recoverability. The Company's estimated tax pools as at December 31, 2021, are as follows:

Category	Deductibility	$000's
Canadian oil and gas property expense (COGPE)	10%	17,628
Successored COGPE	10%	184,777
Canadian development expense (CDE)	30%	47,567
Successored CDE	30%	114,165
Canadian exploration expense (CEE)	100%	-
Successored CEE	100%	23,829
Undepreciated capital cost (UCC)	Primarily 25%, declining balance	99,839
Non-capital losses	100%	235,275
Share/Debt issue costs	5-year straight line	4,832
Other	Various	(3,482)
Total estimated tax pools		724,430

Asset retirement obligations

The Company's asset retirement obligations ("ARO") of $88.7 million pertain to the Company's wells and related infrastructure with the large increase in the 2021 related to the Simonette acquisition and Distinction business combination. The estimated ARO includes assumptions with respect to actual costs to abandon wells or reclaim the property, the time frame in which such costs will be incurred, and annual inflation factors. There is approximately $29.5 million of abandonment and reclamation costs associated with inactive wells or facilities where there is no active operations or attributed reserves. Kiwetinohk is currently working on an abandonment program to proactively manage and reduce the inactive decommissioning liabilities over the next five to seven years.

Environmental sustainability is a key focus area of the Company where all development activities are reviewed to ensure that they are done in the most responsible and prudent manner and in accordance with the Alberta government's liability management framework. The Company's Liability Management Rating ("LMR") is within the Alberta Energy Regulator's requirements and as such, no deposits are required or expected to be required in the near term. The Company's combined LMR at December 31, 2021 is 5.34.

Select quarterly information

	2021				2020			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Production (boe/d)	**12,422**	15,058	10,797	741	645	793	443	1,204
Commodity sales from production ($000)	**70,267**	66,897	42,262	3,242	2,186	2,388	1,305	3,879
Marketing revenue	**58,398**	38,349	17,770	-	-	-	-	-
Cash flow from (used in) operating activities	**25,518**	31,006	(17,125)	(3,579)	(777)	399	(1,776)	493
Per share (basic) [1,2]	0.58	0.90	(0.58)	(0.19)	(0.05)	0.03	(0.14)	0.04
Per share (diluted) [1,2]	0.58	0.90	(0.58)	(0.19)	(0.05)	0.03	(0.14)	0.04
Net income (loss) [2]	**44,306**	(34,080)[2]	13,726[3]	(46,267)	9,732	(3,545)	(3,261)	(7,795)
Per share (basic) [1]	**1.02**	(0.99)	0.47	(2.43)	0.64	(0.27)	(0.26)	(0.61)
Per share (diluted) [1]	**1.02**	(0.99)	0.47	(2.43)	0.64	(0.27)	(0.26)	(0.61)

1 – As part of the Arrangement, Kiwetinohk consolidated the outstanding Kiwetinohk common shares, stock options and performance warrants on a 10 to 1 basis. This MD&A and all information related to common shares, stock options, performance warrants and per share amounts, have been restated to reflect the share consolidation for all periods presented.
2 – The Company has restated Q3 2021 operating expenses by $2.0 million and transportation expenses by $2.4 million as a result of revisions to previously accrued expenses.
3 – The Company has adjusted Q2 2021 gain on acquisition by $1.1 million, deferred tax expense $0.3 million, and share in earnings of associate by $4.6 million due to adjustments to estimated fair values of working capital acquired based on new information on the Simonette and Distinction acquisitions.

Select annual information

	2021	2020	2019
Production (boe/d)	9,801	771	1,242
Commodity sales from production ($000)	182,668	9,758	18,895
Marketing revenue	114,517	-	-
Cash flow from (used in) operating activities	35,820	(1,661)	4,221
Per share (basic) [1]	1.13	(0.13)	0.36
Per share (diluted) [1]	1.13	(0.13)	0.36
Net income (loss)	(22,315)	(4,869)	(19,474)
Per share (basic) [1]	(0.70)	(0.36)	(1.67)
Per share (diluted) [1]	(0.70)	(0.36)	(1.67)
Total assets	614,337	172,993	114,796
Long-term liabilities	124,587	3,448	1,734

1 – As part of the Arrangement, Kiwetinohk consolidated the outstanding Kiwetinohk common shares, stock options and performance warrants on a 10 to 1 basis. This MD&A and all information related to common shares, stock options, performance warrants and per share amounts, have been restated to reflect the share consolidation for all periods presented.

As a result of the Simonette Acquisition and Distinction consolidation, which both occurred on April 28, 2021, the Company had a significant increase to production and operating results beginning the second quarter of 2021.

Capital resources and liquidity

The Company's objective when managing its balance sheet is to maintain a conservative capital structure that provides financial flexibility to execute on strategic and new business opportunities. The Company relies on cash flow from current production, available funding on the Credit Facility and future equity or debt issuances to fund its capital requirements and any potential acquisitions. The Company anticipates that cash flow from operations from the Simonette Acquisition and availability on its Credit Facility will be sufficient to meet working capital requirements and fund anticipated drilling on Simonette and Placid acreage through 2022.

Credit Facility

In 2021, the Company secured a combined $225.0 million senior credit facility from a syndicate of banks of which $96.3 million was initially drawn to fund the Simonette Acquisition. On September 22, 2021, the Company amended and restated its credit agreement and entered into a single $225.0 million Credit Facility with a syndicate of banks. On December 13, 2021, aggregate commitments under the Credit Facility were increased 40%, to $315.0 million after the lenders' semi-annual borrowing base review. The Credit Facility is composed of an operating facility of $65.0 million and a syndicated facility of $250.0 million.

At December 31, 2021 $34.7 million (before deferred financing costs) was outstanding on the Credit Facility along with $52.3 million in letters of credit issue to support transportation and other commitments.

$000	Authorized	Drawn	Letters of credit	Capacity [1]
Credit Facility	315,000	34,698	52,311	**227,991**

1 – 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. See "Non-GAAP Measures" section of this MDA.

$000s	2021	2020
Loans and borrowings	**32,868**	-
Adjusted working capital deficit (surplus) [1]	**18,644**	(54,401)
Net debt (surplus) [1]	**51,512**	(54,401)

1 – 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. See "Non-GAAP Measures" section of this MDA.

The Credit Facility is a 364-day committed facility available on a revolving basis until May 31, 2022, 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, 2023. 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.

Interest payable on amounts drawn under the Credit Facility is at the prevailing bankers' acceptance plus stamping fees, lenders' prime rate or U.S. base rate plus the applicable margins, depending on the form of borrowing by the Company. The applicable margins and stamping fees are based on a sliding scale pricing grid tied to the Company's debt to earnings before interest, taxes, depreciation and amortization ratio ("bank EBITDA"): from a minimum of the bank's prime rate or U.S. base rate plus an applicable margin ranging from 1.75 percent to 5.25 percent or from a minimum of bankers' acceptances rate plus a stamping fee ranging from 2.75 percent to 6.25 percent. The undrawn portion of the Credit Facility is subject to standby fees ranging from 0.6875% to 1.5625% based on the Company's debt to bank EBITDA ratio.

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.

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

EDC Credit Facilities

Subsequent to year end, Kiwetinohk entered into a new $15 million unsecured demand revolving letter of credit facility (the "LC Facility") with a Canadian bank. Kiwetinohk's obligations under the LC Facility are supported by a performance security guarantee ("PSG") from Export Development Canada ("EDC"). The PSG is valid to February 10, 2023 and may be extended from time-to-time at the option of Kiwetinohk and with the agreement of EDC.

Share capital

The Company is authorized to issue an unlimited number of voting common shares. In 2021, the Company fully drew on its remaining equity line of credit with ARC Financial Corp. ("ARC") and the Company raised $32.7 million in a private placement.

As part of the Arrangement, Kiwetinohk issued 10.2 million common shares and acquired all of the Distinction common shares not already owned. All outstanding Kiwetinohk common shares, stock options and performance warrants were consolidated on a 10 to 1 basis with capital warrants being cancelled at the same time. Kiwetinohk also inherited the Distinction reporting issuer status as part of the Arrangement. The share consolidation has been retroactively presented in the following table.

(000s)	Q4 2021	Q4 2020	2021	2020
Weighted average shares outstanding				
Basic	**43,623**	15,203	**31,689**	13,540
Diluted	**43,623**	15,203	**31,689**	13,540
Outstanding securities				
Common shares	**43,675**	18,724	**43,675**	18,724
Stock options	**3,228**	1,288	**3,228**	1,288
Performance warrants	**7,922**	2,578	**7,922**	2,579
Capital warrants	**-**	2,007	**-**	2,007
Total diluted outstanding securities	**54,825**	24,597	**54,825**	24,597

At March 23, 2022 the Company has 44,042,515 common shares outstanding.

Commitments, contractual obligations, and provisions

$000s	2022	2023	2024	2025	2026	Thereafter
Gathering, processing and transport [1]	55.8	63.3	65.3	57.1	12.4	253.9
Natural gas purchases	81.7	-	-	-	-	-
Office, equipment and software	0.3	-	-	-	-	-
Accounts payable	54.4	-	-	-	-	-
Contingent payment consideration	5.0	6.6	-	-	-	-
Lease liabilities	0.6	-	-	-	-	-
Land fund	0.4	-	-	-	-	-
Loans and borrowings	1.8	36.0	-	-	-	-
Risk management contracts	26.1	2.7	-	-	-	-
Other	0.4	0.4	0.4	0.4	0.4	1.1
Total	226.5	109.0	65.7	57.5	12.8	255.0

1 – Gas transportation contracts include Alliance commitments of 90.3 MMcf/d related to the Simonette Acquisition, 29.7 MMcf/d related to Distinction in addition to various NGL and condensate transportation commitments and other processing commitments.

As part of the Simonette acquisition, the Company assumed natural gas transportation commitments of approximately 90.3 MMcf per day to deliver gas to Chicago on the Alliance pipeline through October 2025. The Company has a liquids extraction agreement with Aux Sable through October 2023. Through Distinction, the Company acquired a separate independent transportation agreement with Alliance to deliver 29.7 MMcf/d of natural gas volumes until October 31, 2025 to Chicago that is not contracted to Aux Sable.

The Company currently has secured approximately 80,000 GJ per day of gas supply (approximately 70.1 MMcf per day) from several natural gas producers through 2022, allowing the Company to fully utilize its Alliance pipeline capacity. As a result, the Company is able to use proceeds from purchased gas volumes sold to meet all of its transportation and purchase commitments.

In March 2022, the Company entered into additional commitments for the purchase of natural gas supply through November 2023 for an estimated total of $3.5 million during 2022 and $12.6 million in 2023.

Related party information

For the quarter and year ended December 31, 2021, the Company incurred a total of $0.6 million and $2.5 million, respectively (2020 - $0.3 million and $1.0 million), in the following related party transactions:

- The Company has retained a law firm to provide legal services on corporate matters. A director of the Company is a partner of this law firm.
- The Company has engaged an energy information services company to assist in the evaluation of prospective upstream oil and gas properties. A director of the Company is the CEO of this firm.
- The Company is working with an upstream oilfield services company. A VP of the Company is the president of this oilfield services company. During the fourth quarter of 2021, the VP has resigned from the upstream oilfield service company.

Upon closing of the Arrangement with Distinction, the Company had a net receivable balance of $0.6 million outstanding from previous Directors and employees of Distinction for withholding taxes incurred upon the surrender and exchange of all remaining Distinction restricted share units at the time of closing. The withholding tax receivable balance of $0.6 million was repaid subsequently to December 31, 2021.

All related party transactions are incurred in the normal course of operations and recorded at the exchange amount which approximates the fair value of the services provided.

Health, safety and environmental

As part of integration of the Simonette assets and Distinction Energy, Kiwetinohk is implementing a new health and safety program that applies best practices across all operations. The Company continues to exercise caution with respect to COVID-19 risks by following local government and public health direction and other safeguards.

Kiwetinohk is completing a thorough review of its environmental, social and governance ("ESG") risks and management strategies, and plans to publish its first ESG report in mid-2022 in alignment with the Sustainability Accounting Standards Board ("SASB") data standards for Oil & Gas – Exploration and Production and with the Task Force on Climate-related Financial Disclosures ("TCFD") framework.

Risk factors and risk management

The Company's management team is focused on long-term strategic planning and has identified key material risks, uncertainties and opportunities associated with the Company's business that can impact the financial position, operations, cash flows and future prospects of the business. They include, but are not limited to:

• risks associated with developing and operating the power generation and renewable energy business;	• natural gas, oil and electricity prices;
• the ability of the Company to successfully execute its energy transition strategy;	• 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;	• the risks and limitations of forecasting reserves data;
• risks associated with operating and integrating a newly-combined business;	• global economic and financial conditions including impacts from the Russia Ukraine conflict;
• ready access to capital markets;	• licenses and permits;
• government regulations;	• health, safety and environmental risks;

• competition in the crude oil and natural gas industry;	• carbon taxes and environmental compliance costs;
• coronavirus ("COVID-19");	• market constraints and access to services and equipment;
• talent, recruitment and retention of key personnel;	• technology risks;
• seasonality;	industry shortages;
• impaired oil and gas operating or social license;	• access to capital and ability to sell and recover capital;
• project development, construction and execution;	• transportation and processing commitments;
• hedging and risk management contracts;	• growth management;
• limited number of shareholders;	• inflation and supply chain disruption.

In order to reduce risk the Company employs subject matter experts that are highly qualified professionals with clearly defined roles and responsibilities, seeks to operate and control the majority of properties and projects, utilizes proven technologies and will pursue new technologies where appropriate. Other risks are discussed under "Risk Factors" as presented in the Company's Annual Information Form ("AIF") dated March 23, 2022 available on the SEDAR website at www.sedar.com.

Internal controls

Internal control over financial reporting is a process designed to provide reasonable assurance regarding the preparation of relevant, reliable, and timely financial information and that all the Company's assets are safeguarded, and daily transactions are appropriately authorized.

The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") are responsible for internal controls over financial reporting to be designed under their supervision. Given the size of the Company and high involvement of the CEO and CFO in the day-to-day operating activities of the Company, there are appropriate disclosure controls and procedures in place to provide reasonable assurance that (i) material information relating to the Company is made known to the Company's CEO and CFO by others, and (ii) information required to be disclosed by the Company to its board of directors is recorded, processed and reported in a timely manner.

Financial reporting

Critical accounting estimates

The significant accounting judgements and estimates used by the Company are discussed in the notes of the December 31, 2021 financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates.

The critical accounting estimates that may impact the Company's financial and operating results include:

- acquisition date fair value of identifiable assets in business combinations;
- estimated depletion and impairment which is based on estimates of oil and natural gas reserves;
- estimates of economically recoverable oil and natural gas reserves which are impacted by production rates, commodity prices, royalties, operating costs and other relevant assumptions;
- determination of technical feasibility and commercial viability of exploration and evaluation projects;
- estimated asset retirement obligations based on current legal and constructive requirements, technology, price levels, cost inflation, the risk-free interest rate, timing and expected plans for remediation;
- share-based compensation expense based on Black-Scholes option pricing model inputs including fair value of shares, issue date, expected volatility, dividend yield, forfeiture and discount rates;
- recognition of deferred tax assets based on probability of future taxable profits; and

- estimated fair value of risk management contracts based on forecast commodity prices and foreign exchange rates.

Future Accounting Pronouncements

The following are future accounting pronouncements issued and not yet effective as at December 31, 2021. The Company intends to adopt these standards as they become effective and is evaluating the impacts, if any, on the Financial Statements and does not expect a significant impact.

IAS 1 – Presentation of Financial Statements

Effective January 1, 2023, amendments to the classification of liabilities as non-current include the requirement that a right to defer settlement must have substance and exist at the end of the reporting period.

IAS 8 – Accounting Policies, Changes in Accounting Estimates and Errors

Effective January 1, 2023, amendments to IAS 8 include additional clarification on the determination of changes in accounting policies from changes in accounting estimates. The development of accounting estimates includes selecting a measurement technique and choosing the inputs to be used when applying the chosen measurement technique.

IAS 16 – Property, plant, and equipment

Effective January 1, 2022, proceeds from selling items before property, plant and equipment is available for use is recognized in profit or loss, together with the cost of producing those items.

IAS 37 – Provisions, Contingent Liabilities and Contingent Assets

Effective January 1, 2022 IAS 37 requires the recognition of onerous contracts when the unavoidable costs of meeting obligations under a contract exceed the economic benefits expected to be received under it. The unavoidable costs under a contract reflect the least net cost of exiting from the contract, which is the lower of the cost of fulfilling it and any compensation of penalties arising from the failure to fulfill it. Amendments include clarification on incremental costs and the allocation of other direct costs as costs included of fulfilling a contract.

Financial instruments and risk management

The Company's financial instruments are classified and measured at amortized cost or fair value through profit of loss ("FVTPL").

Financial assets are measured at amortized cost if the financial asset is held within a business model whose objective is to hold financial assets in order to collect contractual cash flows, and the contractual cash flows give rise on specified dates to cash flows that are solely payments of principal and interest on the principal amount outstanding. All other financial assets are measured at FVTPL.

All financial liabilities are measured at amortized cost except for those measured at FVTPL including contingent payment consideration and risk management contracts.

Credit risk

Credit risk is the risk of financial loss to the Company if a counterparty to a financial instrument fails to meet its contractual obligation. The Company is exposed to credit risk with respect to its cash, accounts receivable and risk management contracts.

The Company's cash balances and risk management contracts are held with large established financial institutions. The Company manages credit risk by ensuring transactions are only entered into with counterparties with strong credit worthiness and regular internal reviews are performed on the Company's short-term exposure with these counterparties.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The Company operates in a capital-intensive industry with medium to long-term cash cycles. The Company may 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 regularly monitors its cash requirements by assessing its ability to generate cash flow from operations, access to external financing, debt obligations as they become due, and its expected future operating and capital expenditure requirements.

The Company's financial instruments recognized on the consolidated balance sheet includes cash, accounts receivable, funds held in trust, accounts payable and accrued liabilities, long term liability, contingent liabilities, loans and borrowings, and risk management contracts. The primary risks are described in Note 19 of the Financial Statements.

Market risk
Market risk is the risk that fluctuations in market prices, such as foreign exchange rates, commodity prices, and interest rates will affect the Company's consolidated statement of net loss and comprehensive loss to the extent the Company has outstanding financial instruments.

Off-balance sheet arrangements
Except as disclosed in the Financial Statements, the Company has not entered into any guarantee or off balance sheet arrangements that would materially impact the financial position or results of operations as at December 31, 2021.

Other

Non-GAAP measures
Certain information set forth in this document contains non-GAAP measures, including "operating netback", "adjusted operating netback", "adjusted funds flow from (used in) operations", "free funds flow (deficiency)" from operations, "adjusted working capital (deficit) surplus", "credit facility capacity", "net debt (surplus)", "net debt to adjusted funds flow from operations", "net marketing income (loss)", "return on average capital employed" and "average capital employed". These non-GAAP measures presented in this MD&A 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 Financial Statements. Readers are cautioned that these non-GAAP measures do not have any standardized meanings and 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.

The Company will use certain measures to analyze operational and financial performance. These non-GAAP measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities nor should it be viewed as an alternative to other possible comparable IFRS measures.

Operating netback
Operating netback is calculated on a per boe basis as commodity sales from production less royalty, operating, and transportation expenses. Kiwetinohk also discloses *adjusted operating netback* which includes realized gain or loss on risk management contracts that settled in cash during the respective period and marketing income. Disclosing the impact of the realized gain or loss on risk management contracts and marketing income provides management and investors with a measure that reflects how the Company's risk management program and marketing income impacts its netback.

Management believes that operating netback and adjusted operating netback are key industry benchmarks and useful measure of performance that provides the Company and investors with information that is commonly used by other oil and natural gas producers. The measurement on a per boe basis assists management with evaluating operating performance on a comparable basis.

Adjusted funds flow from (used in) operations

Adjusted funds flow from (used in) operations is cash flow from (used in) operating activities before changes in net change in non-cash working capital from operating activities, asset retirement obligations, restructuring costs, acquisition costs and settlement agreement costs. Management considers adjusted funds flow from (used in) operations as a key measure to analyze performance as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments, asset retirement obligations and to repay debt.

Free funds flow (deficiency) from operations

Free funds flow (deficiency) from operations is adjusted funds flow from (used in) operations less capital expenditures prior to property acquisitions. Management uses free funds flow as a key measure to analyze the Company's ability to generate returns for investors and repay debt.

Adjusted working capital (deficit) surplus

Adjusted working capital (deficit) surplus is comprised of current assets less current liabilities excluding risk management contracts. Adjusted working capital (deficit) surplus is used by management to provide a more complete understanding of the Company's liquidity. The current portion of risk management contracts has been excluded as there is no intention to realize these financial instruments and they are also subject to a high degree of volatility prior to ultimate settlement.

$000s	2021	2020	2019
Current assets	**47,557**	57,692	30,693
Current liabilities	**(92,316)**	(3,291)	(3,181)
Working capital (deficit) surplus	**(44,759)**	54,401	27,512
Short term risk management contracts	**26,115**	-	-
Adjusted working capital (deficit) surplus	**(18,644)**	54,401	27,512

Credit facility capacity

Credit facility capacity is the total Credit Facility available, less amounts drawn on the Credit Facility and outstanding letters of credit. Credit facility capacity is used by management to assess the Company's liquidity.

Net debt (surplus)

Net debt (surplus) is comprised of loans and borrowings plus adjusted working capital deficit (surplus) and represents the Company's net financing obligations. Net debt (surplus) is used by management to provide a more complete understanding of the Company's capital structure and provides a key measure to assess the Company's liquidity.

$000s	2021	2020	2019
Loans and borrowings	**32,868**	-	-
Adjusted working capital deficit (surplus)	**18,644**	(54,401)	(27,512)
Net debt (surplus)	**51,512**	(54,401)	(27,512)

Net debt to adjusted funds flow from operations

Net debt to adjusted funds flow from operations is a liquidity ratio that represents the Company's ability to cover its net debt with its adjusted funds flow from operations. Net debt to adjusted funds flow is calculated as net debt divided by adjusted funds flow from operations.

Net marketing income (loss)
Net marketing income (loss) is revenue from the sale of purchased natural gas less marketing expense which includes commodity purchases, transportation expense and related marketing fees. Net marketing income (loss) is used as a key measure of how the Company is managing its take or pay pipeline commitments.

Return on average capital employed ("ROACE")
ROACE is expressed as adjusted funds flow from operations divided by the average of the opening and closing capital employed for the twelve months preceding period. ROACE is used by management to measure the effectiveness of its capital management and its ability to generate returns for shareholders.

Average capital employed
Average capital employed is average shareholders' equity plus net debt (surplus). Average capital employed is used in the Company's calculate of ROACE.

$000s	2021	2020	2019
Shareholders' equity	**397,434**	166,254	109,881
Add: Net debt	**51,512**	(54,401)	(27,512)
Capital employed	**448,946**	111,853	82,369
Average capital employed	**280,400**	97,111	

Forward-Looking Statements
Certain information set forth in this MD&A contains forward-looking information and statements. Such forward-looking statements or information are provided for the purpose of providing , without limitation, information about management's current expectations of business strategy, and management's assessment of future plans and operations. Forward-looking statements or information typically contain statements with words such as "anticipate", "believe", "expect", "plan", "intend", "estimate", "propose", "project", "potential" or similar words suggesting future outcomes or statements regarding future performance and outlook. Readers are cautioned that assumptions used in the preparation of such information may prove to be incorrect. Events or circumstances may cause actual results to differ materially from those predicted as a result of numerous known and unknown risks, uncertainties and other factors, many of which are beyond the control of the Company.

In particular, this MD&A contains forward-looking statements pertaining to the following:
- the impact of low-cost natural gas produced from Kiwetinohk's upstream resources on the Company's gross margin;
- the Company's growth strategy, including its focus on consolidation of strategic upstream assets, identification and development of natural gas-fired power generation and renewable projects and the Company's plans for integration of its upstream and power portfolios;
- the Company's plans for developing a low emission power generation business as a source of power for Alberta's electrical grid, including development of its natural gas-fired and solar and wind power generation projects and expectations with respect to future opportunities for other renewable energy projects;
- timing for the Company's solar and Firm Renewable projects to reach FID;
- anticipated production increases into the first quarter of 2023;
- future investigations by the Company of CCUS and application for grants related thereto;
- industry volatility and uncertainty around the timing and extent of a COVID-19 recovery;
- reactivation of the Alliance meter station at the Bigstone Sweet Plant in the first quarter of 2022;
- future taxes payable by the Company;
- future requirements with respect to LMR deposits of the Company;
- the timing and costs of the Company's capital projects, including drilling and completion of certain wells;
- the anticipated outcomes of the Company's capital program;
- operating costs in 2022;

- near-term land expiries and impairment charges associated therewith;
- sufficiency of funds to meet the Company's working capital requirements and anticipated drilling on the Simonette Acquisition and Distinction acreage through 2022;
- the anticipated outcomes of successful execution of the Company's investment and financing strategies for its power project portfolio;
- use of the Credit Facility for working capital purposes to fund go forward capital plans;
- treatment under governmental regulatory regimes, including taxes and tax regimes, environmental and greenhouse gas regulations and related abandonment and reclamation obligations, and Indigenous, landowner and other stakeholder consultation requirements;
- the expected demand for, and prices and inventory levels of, petroleum products, including NGL; and
- the impact of current market conditions on the Company.

In addition to other factors and assumptions that may be identified in this MD&A, assumptions have been made regarding, among other things:

- the timing and costs of the Company's capital projects;
- the impact of increasing competition;
- the general stability of the economic and political environment in which the Company operates;
- the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner;
- the ability of the operator of the projects that the Company has an interest in to operate in a safe, efficient and effective manner;
- future commodity and power prices;
- currency, exchange and interest rates;
- the regulatory framework regarding royalties, taxes, power, renewable and environmental matters in the jurisdictions in which the Company operates; and
- the ability of the Company to successfully market its products.

Readers are cautioned that the foregoing list is not exhaustive of all factors and assumptions that have been used. Although the Company 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.

Forward-looking statements or information 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 or information. These risks and uncertainties include, among other things:

- the ability of management to execute its business plan;
- general economic and business conditions;
- the risk of instability affecting the jurisdictions in which the Company operates;
- the risks of the power and renewable industries;
- operational and construction risks associated with certain projects;
- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld;
- uncertainty involving the forces that power certain renewable projects;
- the Company's ability to enter into or renew leases;
- potential delays or changes in plans with respect to power and solar projects or capital expenditures;
- fluctuations in commodity and power prices, foreign currency exchange rates and interest rates;
- risks inherent in the Company's marketing operations, including credit risk;
- health, safety, environmental and construction risks;
- risks associated with existing and potential future lawsuits and regulatory actions against the Company;
- uncertainties as to the availability and cost of financing; and

- financial risks affecting the value of the Company's investments.

Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties.

The forward-looking statements and information contained in this MD&A speak only as of the date of this MD&A 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.

Future oriented financial information

This MD&A contains information that may constitute future-orientated financial information or financial outlook information (collectively, "FOFI") about the Company's prospective financial performance, financial position or cash flows, all of which is subject to the same assumptions, risk factors, limitations and qualifications as set forth above. In particular, this MD&A contains expected capital costs and power generation capacity of the Company's proposed power generation capital projects and 2022 financial outlook information for the Company, including expected royalty rates, operating costs, transportation expenses, corporate G&A expenses and cash taxes. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise or inaccurate and, as such, undue reliance should not be placed on FOFI. The Company's actual results, performance and achievements could differ materially from those expressed in, or implied by, FOFI. Kiwetinohk has included FOFI in order to provide readers with a more complete perspective on the Company's future operations and management's current expectations relating to the Company's future performance. Readers are cautioned that such information may not be appropriate for other purposes. FOFI contained herein was made as of the date of this MD&A. Unless required by applicable laws, the Company does not undertake any obligation to publicly update or revise any FOFI statements, whether as a result of new information, future events or otherwise.

Abbreviations

$M	thousand dollars
$MM	million dollars
$/bbl	dollars per barrel
$/boe	dollars per barrel equivalent
$/GJ	dollars per gigajoule
$/Mcf	dollars per thousand cubic feet
AECO	the daily average benchmark price for natural gas at the physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
bbl(s)	barrel(s)
bbl/d	barrels per day
boe	barrel of oil equivalent, including crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe per six Mcf of natural gas)
boe/d	barrel of oil equivalent per day
DI	daily index
EBITDA	earnings before interest, income taxes, depreciation, depletion, and amortization
E&E	exploration and evaluation
GJ	gigajoule
GJ/d	gigajoule per day
Henry Hub	the daily average benchmark price for natural gas at the distribution hub on the natural gas pipeline system in Erath, Louisiana
mbbls	thousand barrels
MMboe	million barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic standard feet per day
MI	monthly index
MMcf/d	million cubic feet per day
MMBtu	one million British Thermal Units (BTU) is a measure of the energy content in gas
MMBtu/d	one million British thermal units per day
MW	one million watts
MW.h	electrical energy of one million watts acting for one hour
NGLs	natural gas liquids, which includes butane, propane, and ethane
PP&E	property, plant, and equipment
US$/bbl	US Dollars per barrel
US$/mmbtu	US Dollars per million British thermal units
WTI	West Texas Intermediate, the reference price paid for crude oil of standard grade in US dollars at Cushing, Oklahoma

Oil and gas advisories

For the purpose of calculating unit costs, natural gas is converted to a barrel of oil equivalent using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated. 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.

CORPORATE INFORMATION

Management

Pat Carlson
Chief Executive Officer

Jakub Brogowski
Chief Financial Officer

Mike Backus
Chief Operating Officer, Upstream

John Maniawski
President, Green Energy Division

Janet Annesley
Chief Sustainability Officer

Sue Kuethe
Executive VP, Land and Community Inclusion

Mike Hantzsch
Senior Vice President, Midstream and Market Development

Kurt Molnar
Senior Vice President, Business Development

Lisa Wong
Senior Vice President, Business Systems

Chris Lina
Vice President, Projects

Farid Shirkavand
Vice President

Board of Directors

Kevin Brown
Board Chair

Beth Reimer-Heck
Lead Director

Judith Athaide
Director

Pat Carlson
Director and CEO

Leland Corbett
Director

Nancy Lever
Director

Kaush Rakhit
Director

Timothy Schneider
Director

Steve Sinclair
Director

John Whelen
Director

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Royal Bank of Canada
Bank of Nova Scotia
Business Development Bank of Canada

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Calgary, AB

Reserve Engineers

McDaniel & Associates Consultants Ltd.
Calgary, AB

Legal Counsel

Stikeman Elliott LLP
Norton Rose Fulbright Canada LLP
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Transfer Agent

Computershare
Calgary, AB

Stock Symbol

KEC
Toronto Stock Exchange