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 three and nine months ended September 30, 2022. The Company was formed as part of the amalgamation of Kiwetinohk Resources Corp. ("KRC") and Distinction Energy Corp. ("Distinction", previously known as Delphi Energy Corp.). Kiwetinohk's common shares commenced trading on the Toronto Stock Exchange under the symbol KEC on January 14, 2022.

This MD&A should be read in conjunction with the Company's condensed consolidated interim financial statements as at and for the three and nine months ended September 30, 2022 (the "Financial Statements") and the audited financial statements as at and for the year ended December 31, 2021. Additional information 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", "Future Oriented Financial Information", "Abbreviations" and "Oil and Gas Advisories" 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 November 9, 2022.

Overview of business

Kiwetinohk's mission is to build a profitable energy transition business which provides clean, reliable, dispatchable and affordable 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 competitive economic resource potential. In 2021, the Company completed acquisitions of upstream assets and associated infrastructure, with an additional working interest in a portion of these assets acquired during the third quarter of 2022. These assets consist of high-netback, liquids-rich natural gas production with development upside and 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 examining potential brownfield development opportunities across a diversified Alberta- based power generation project portfolio that includes clean, affordable, 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-front end engineering and design ("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, affordable 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

	Q3 2022	Q2 2022	Q3 2021	YTD 2022	YTD 2021
Sales volumes					
Oil & condensate (bbl/d)	**5,558**	6,401	4,608	**5,446**	2,855
NGLs (bbl/d)	**1,944**	1,870	1,814	**1,793**	1,048
Natural gas (Mcf/d)	**53,912**	51,232	51,817	**49,741**	30,089
Total (boe/d)	**16,487**	16,810	15,058	**15,529**	8,918
Oil and condensate % of production	**34%**	38%	31%	**35%**	32%
NGL % of production	**12%**	11%	12%	**12%**	12%
Natural gas % of production	**54%**	51%	57%	**53%**	56%
Realized prices					
Oil & condensate ($/bbl)	**114.48**	131.53	80.61	**121.48**	78.14
NGLs ($/bbl)	**75.50**	86.71	49.74	**76.68**	46.02
Natural gas ($/Mcf)	**10.20**	9.98	5.12	**9.01**	4.67
Total ($/boe)	**80.86**	90.17	48.29	**80.31**	46.17
Royalty expense ($/boe)	**(12.51)**	(2.69)	(6.49)	**(7.34)**	(4.83)
Operating expenses ($/boe)	**(11.13)**	(12.11)	(8.14)	**(11.04)**	(8.14)
Transportation expenses ($/boe)	**(6.63)**	(4.67)	(5.72)	**(5.34)**	(5.03)
Operating netback [1] ($/boe)	**50.59**	70.70	27.95	**56.59**	28.17
Net commodity sales from purchases ($/boe) [1]	**21.64**	3.58	3.71	**9.18**	1.63
Realized loss on risk management – purchases ($/boe)[1]	**(19.41)**	(2.60)	(4.21)	**(6.77)**	(2.35)
Realized loss on risk management ($/boe) [4]	**(16.92)**	(18.49)	(7.61)	**(16.96)**	(7.00)
Adjusted operating netback [1]	**35.90**	53.19	19.84	**42.04**	20.45
Financial results ($000s, except per share amounts)					
Commodity sales from production	**122,644**	137,931	66,898	**340,441**	112,401
Net commodity sales from purchases (loss) [1]	**32,813**	5,486	5,144	**38,895**	3,977
Cash flow from (used in) operating activities	**91,710**	38,780	29,643	**155,822**	10,311
Adjusted funds flow from (used in) operations [1]	**49,342**	76,232	23,821	**162,576**	39,066
Per share basic [2,3]	**1.12**	1.73	0.69	**3.69**	1.41
Per share diluted [2,3]	**1.10**	1.71	0.69	**3.65**	1.41
Net debt to annualized adjusted funds flow from operations [1]	**0.65**	0.33	0.95	**0.65**	0.95
Free funds flow (deficiency) from operations (excluding acquisitions/dispositions) [1]	**(11,119)**	23,884	9,068	**(4,445)**	20,125
Net income (loss)	**55,379**	44,854	(34,080)	**75,681**	(66,621)
Per share basic [2,3]	**1.26**	1.02	(0.99)	**1.72**	(2.41)
Per share diluted [2,3]	**1.24**	1.01	(0.99)	**1.70**	(2.41)
Capital expenditures prior to acquisitions/ (dispositions)	**60,461**	52,348	14,753	**167,021**	18,941
Acquisitions (dispositions)	**59,181**	(1,620)	-	**57,323**	-
Total capital expenditures	**119,642**	50,728	14,753	**224,344**	18,941
Balance sheet ($000s, except share amounts)					
Total assets	**837,349**	744,454	588,152	**837,349**	588,152
Long-term liabilities	**214,536**	180,619	138,034	**214,536**	138,034
Net debt (surplus) [1]	**125,263**	55,027	32,620	**125,263**	32,620
Adjusted working capital surplus (deficit) [1]	**(24,065)**	19,736	(84)	**(24,065)**	(84)
Weighted average shares outstanding [2,3]					
Basic	**44,114,105**	44,061,471	34,321,566	**44,004,315**	27,667,430
Diluted	**44,795,079**	44,502,777	34,321,566	**44,491,336**	27,667,430
Shares outstanding end of period [2]	**44,117,187**	44,111,135	43,610,140	**44,117,187**	43,610,140

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.

2 – As part of the Arrangement (as defined below), 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 – Realized loss on risk management contracts includes settlement of financial hedges on production and foreign exchange.

Quarterly Highlights

Upstream

- Quarterly average production of 16,487 boe/d, despite no production additions from new wells.
- Operating netback[1] of $50.59/boe before hedging or $35.90/boe after hedging and net commodity sales from purchases.
- 89% of natural gas sales into higher-priced Chicago market. During the quarter, helping realize $10.20/Mcf for corporate gas sales ($3.87/Mcf higher than average AECO 7A Monthly Index price in Alberta).
- Operating costs of $11.13/boe, 8% lower than Q2 2022.
- Closed $59.2 million Placid Montney asset acquisition on September 15, 2022.
- Upstream capital spending of $118.0 million ($58.8 million excluding Placid acquisition).
- Net commodity sales from purchases[1] of natural gas in the quarter of $32.8 million before hedging ($3.4 million or $2.23/boe after hedging).

Green Energy and Carbon Capture

- Alberta Utilities Commission ("AUC") power plant approvals received for the 400 MW Homestead Solar Project ("Homestead") and 101 MW Opal Firm Renewable Project ("Opal"). AUC transmission approvals are still required.
- Attained site control at Opal and awaiting Alberta Environment and Protected Areas ("AEPA") approval.
- Advanced Homestead and Opal financing discussions with final investment decisions ("FID") targeted for the second half of 2023, later than previously planned due to regulatory congestion.
- After quarter end, the Alberta government awarded Kiwetinohk the right to advance planning on two carbon capture and storage hubs, Opal Carbon Hub and Natural Gas Combined Cycle ("NGGC") 2 Carbon Hub, a key enabler of Kiwetinohk's low carbon power and hydrogen objectives and 10-year strategic plan.

Financial

- Adjusted funds flow from operations[1] was $49.3 million, or $1.10/share (diluted), in the quarter and $162.6 million, or $3.65/share (diluted) for the first nine months of the year.
- Free funds flow from operations[1] was a deficit of $11.1 million (before acquisitions).
- Net debt increased to $125.3 million, primarily because of the $59.2 million consolidation of Placid working interests late in the third quarter.
- Net debt to annualized adjusted funds flow from operations[1] of 0.65x at quarter end, continues to be below the target corporate ceiling of 1.0x.
- Semi-annual redetermination on the senior secured extendible revolving facility credit facility completed subsequent to quarter end with no change to the borrowing base of $375 million. Available credit facility capacity[1] was $245.8 million at September 30, 2022.

[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. Please refer to the section "Non-GAAP Measures" herein.

Guidance update

Management remains confident in the previously communicated 2022 upstream production and capital spending guidance. Select updates have been made incorporating first nine-month actuals, timing of remaining drilling for the calendar year and adjustments due to cost inflation.

New wells put onstream in late October are delivering strong performance above budget expectations. However, timing of the new well tie-ins resulted in Kiwetinohk not realizing this new production during the quarter. Estimates for capital and production for the year remain on track.

The Company added one spud in the Placid Montney area in 2022. Kiwetinohk anticipates a net reduction of three wells spud in 2022 as four Simonette Duvernay wells are now scheduled to spud in January versus December 2022. Deferred capital is offset through pre-investment into planned 2023 activity.

Operating costs improved less than expected in the quarter due to the timing of the new production, workovers and in-field inflation. Operating cost guidance increased to $10.00-$11.00/boe for the year.

Transportation costs were higher quarter-over-quarter due to a higher portion of natural gas production being shipped to Chicago on the Alliance Pipeline. Kiwetinohk expects to continue shipping approximately 90% of its natural gas production on the Alliance Pipeline in the fourth quarter and has tightened transportation guidance to $5.50-$6.00/boe for the year.

Management is preparing the 2023 budget and operating plans and expects to release 2023 guidance in mid-December 2022.

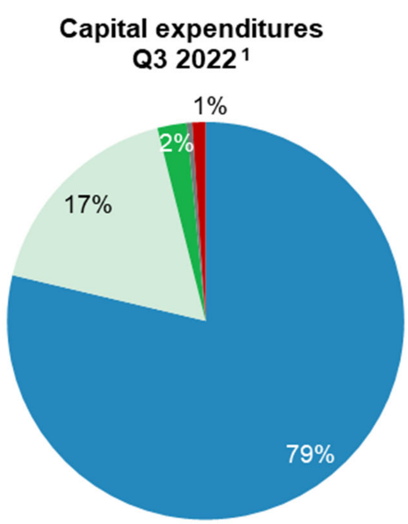
2022 financial & operational guidance		Revised November 10, 2022,	Revised August 22, 2022,	Original January 12, 2022,
Production (2022 average) [1]	Mboe/d	16.0 - 18.0	16 - 18.0	13.0 - 15.0
Oil & liquids	Mbbl/d	8.00 - 8.80	8.00 - 8.80	6.50 - 7.50
Natural gas	MMcf/d	48.0 – 55.2	48.0 – 55.2	39 - 45
Production by market [2]	%	100%	100%	100%
Chicago	%	80% - 85%	80% - 85%	87% - 97%
AECO	%	15% - 20%	15% - 20%	3% - 13%
Financial				
Royalty rate	%	10% - 12%	10% - 12%	12% - 15%
Operating costs	$/boe	$10.00-$11.00	$8.25 - $9.00	$7.50 - $8.50
Transportation	$/boe	$5.50 - $6.00	$5.00 - $6.00	$5.00 - $6.00
Corporate G&A expense [3]	$MM	$18 - $20	$18 - $20	$15 - $18
Cash taxes [4]	$MM	$0	$0	$0
Capital guidance	$MM	290 - 310	290 - 310	210 - 240
Upstream	$MM	275 - 290	275 - 290	200 - 220
Green Energy	$MM	15 - 20	15 - 20	10 - 20
Drilling - Fox Creek	wells	13	16	11
Duvernay	wells	11	15	10
Montney	wells	2	1	1

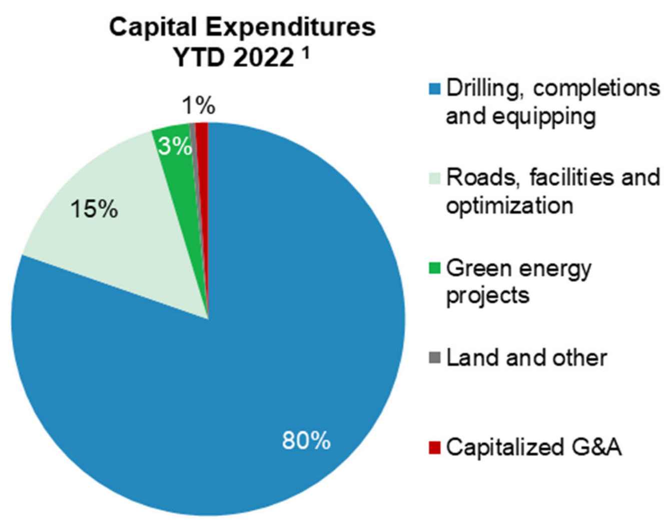
2022 financial & operational guidance (continued)		Revised November 10, 2022	Revised August 22, 2022	Original January 12, 2022
2022 Adjusted Funds Flow from Operations sensitivities [5,6,7]				
US$70/bbl WTI & US$4.50/MMBtu HH	$MM	$220 - $235	$230 - $255	$145 - $155
US$80/bbl WTI & US$5.00/MMBtu HH	$MM	$225 - $240	$240 - $265	$165 - $175
2022 Net debt to Adjusted Funds Flow from Operations sensitivities [5,6,7]				
US$70/bbl WTI & US$4.50/MMBtu HH	X	0.7x	0.7x	1.0x
US$80/bbl WTI & US$5.00/MMBtu HH	X	0.6x	0.6x	0.7x

1 – Production and cash operating costs include scheduled Fox Creek plant turnarounds.
2 – Chicago sales of ~90% expected for rest of year.
3 – Includes G&A expenses for all divisions of the Company – Corporate, Upstream, Green Energy (power & hydrogen) and Business Development.
4 – Strip pricing as of October 10, 2022. See "Non-GAAP Measures".
5 – 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. Please refer to the section "Non-GAAP Measures" herein.
6 – The November 10, 2022 guidance used Q3/22 actual prices with US$70/Bbl WTI flat; US$4.50/MMBtu HH flat; US$0.73/CAD flat thereafter for remainder of 2022. Previously announced guidance has not been adjusted to reflect revised pricing.
7 – The November 10, 2022 guidance used Q3/22 actual prices with US$80/Bbl WTI flat; US$5.00/MMBtu HH flat; US$0.75/CAD flat thereafter for remainder of 2022. Previously announced guidance has not been adjusted to reflect revised pricing.

Capital expenditures

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Drilling, completions, and equipping	**47,580**	12,820	**134,171**	14,551
Roads, facilities and optimization	**10,514**	157	**25,053**	890
Green energy projects	**1,442**	579	**5,211**	1,453
Land and other	**273**	320	**798**	785
Capitalized G&A	**652**	877	**1,788**	1,262
Total capital	**60,461**	14,753	**167,021**	18,941
Acquisitions (dispositions)	**59,181**	-	**57,323**	282,414
Total capital and acquisitions	**119,642**	14,753	**224,344**	301,355





1 – Capital expenditures shown are before acquisitions and dispositions.

Acquisitions

On September 15, 2022, the Company acquired an incremental working interest in its Placid Montney asset for cash consideration of $59.2 million ("Placid Acquisition"). The Placid Acquisition includes an estimated 1,200 boe/d (45% oil & liquids) of current Montney production at the time of closing and increases Kiwetinohk's Placid area natural gas processing and condensate handling capacity to 100 MMcf/d and 5,000 bbl/d respectively (an increase of 30 MMcf/d and 1,750 bbl/d). During the third quarter of 2022, the Placid Acquisition contributed approximately 140 boe/d to average production reflecting fifteen days of operation during the quarter. Kiwetinohk obtained an incremental 14.12% ownership in the 14-28 Bigstone sweet natural gas processing facility, bringing its total working interest to 39.31%. Total owned processing capacity at the Bigstone sweet natural gas processing facility increased from 20 MMcf/d to 31 MMcf/d.

The Placid Acquisition increased Kiwetinohk's working interest to 100% in 53,000 Montney acres in the area where all its new Montney drilling has occurred in the past two years and consolidates Kiwetinohk's position in the Placid Montney area and increases its average working interest over 79,000 acres in the region to 88.2%. It also added 12.9 MMboe of total proved plus probable reserves, based on the independent reserves report of McDaniel & Associates Consultants Ltd. effective as of December 31, 2021.

Drilling, completions and equipping

Steady performance from existing assets and the addition of six new development wells year-to-date contributed to average third quarter production rates of 16,487 boe/d. Significant Duvernay activity is underway at Simonette, the focus area of the 2022 development program. The two wells drilled in late 2021 and an additional four wells drilled during the nine-month period are all producing through permanent facilities and on average, performing as expected.

The Company finished drilling four additional wells on a single pad during the third quarter with completion operations ongoing at quarter end. It has also finished drilling at a two-well pad in the northern part of Simonette offsetting the wells drilled and completed earlier this year. The six additional wells are scheduled to come on production in the fourth quarter.

Roads, facilities and optimization

During the three and nine month periods ended September 30, 2022, the Company spent $10.5 million and $25.1 million, respectively, on construction, facilities and production optimization. Over 80% of the spending was focused on the construction, equipping and tie-in of new wells required to complete the Company's drilling and completions program. The remaining costs are related to front-end engineering work for plant expansions.

Green energy development projects

Kiwetinohk continued to advance its solar and gas-fired power projects in the AESO queue and added a second natural gas-fired 'firm renewable' development project into the AESO process bringing its total power project development portfolio to 2,150 MW.

Based on discussions with Alberta regulatory bodies subsequent to quarter end, Kiwetinohk has been advised that the regulatory process review for the Homestead Solar project to receive transmission approval should be deferred by approximately six months from the previously announced schedule. Kiwetinohk's understanding is the regulatory process delay is the result of significant congestion of proposed power projects in the competitive Alberta power market, which is not unique to Homestead or the Company's project portfolio. Based on the Homestead regulatory process experience, and Kiwetinohk's financial risk management processes, management is proactively adjusting development project timing across its solar and firm renewable project portfolio by three-to-six months.

The adjustments being made to anticipated project schedules are based on current approval time frames being experienced in the current Alberta regulatory environment. Other potential risks to our project timeline include but are not limited to additional regulatory backlogs, potential stakeholder concerns raised during the regulatory process, availability of materials and labor, etc., which have not been considered in the project schedule.

Homestead Solar Power Project

On September 22, 2022, the 400-MW Homestead Solar power plant received AUC power plant approval. AUC transmission application preparation is advancing, including ongoing consultation and engagement with the community. Anticipated AUC transmission approval and FID now expected in Q4 2023. Kiwetinohk continues to evaluate engineering, procurement, and construction ("EPC") bids for Homestead and to discuss financing options with potential strategic partners.

Accordingly, for Homestead Solar, Kiwetinohk expects:

- Earliest FID of Q4 2023
- Earliest commercial operations date ("COD") of Q4 2025

Opal Firm Renewable Project

The 101 MW Opal Firm Renewable project received AUC power plant approval on August 3, 2022, secured land in September 2022 and awaiting Alberta Environment and Protected Areas approval. Once EPC pricing discussions are more advanced with selected vendors Kiwetinohk will update its Opal capital cost estimate.

Accordingly, for Opal Firm Renewable, Kiwetinohk expects:

- Earliest FID of Q4 2023
- Earliest COD of Q4 2025

Granum Solar Power Project and Phoenix Solar Power Project

Kiwetinohk continued to progress its 350 MW Granum Solar ("Granum") and 170 MW Phoenix Solar ("Phoenix") projects through environmental reviews and AESO processes during the quarter. Granum entered AESO Stage 2 on August 2, 2022 and Phoenix began environmental studies and stakeholder consultations. Kiwetinohk increased the capacity of Granum to 350 MW (from 300 MW) and Phoenix to 170 MW (from 150 MW) following project optimization and evaluation of potential transmission capacity.

Based on Homestead Project regulatory process experience, the Company expects

- Earliest FID of Q2 2024 for Granum and Q1 2024 for Phoenix
- Earliest COD of Q2 2026 for Granum and Q3 2025 for Phoenix

Development of Kiwetinohk's NGCC 1 and NGCC 2 projects advanced with pre-FEED (front end engineering and design) analysis, CCUS evaluation and preliminary environmental scoping.

Early-stage development and design factors and the status of each project as at November 9, 2022 are summarized in the following table:

Early-stage Green Energy development, design factors & status	Homestead (Solar 1)	Opal (Firm Renewable 1)	Granum (Solar 2)	Phoenix (Solar 3)	NGCC 2	NGCC 1
Capacity (nameplate, AC) [6]	400 MW	101 MW	350 MW	170 MW	500 MW	500 MW
Capacity (net to grid, AC)	400 MW	97 MW	350 MW	170 MW	460 MW	460 MW
AESO stage	3	2	2	2	2	2
Site control	Secured	Secured	Secured	Secured	In progress	Secured
Consultation (plant/transmission)	Completed/ Underway	Completed/ Planning	Underway/ Planning	Underway/ Planning	Planning/ Planning	Planning/ Planning
Regulatory / Environmental [7]	AUC power plant application approved; AEPA low risk rating	AUC power plant application approved; AEPA application submitted	AUC applications to be filed; AEPA low risk rating	AUC applications to be filed; AEPA low risk rating	Work underway	Work underway
Engineering	FEED completed; EPC bids under review	FEED completed; detailed engineering and cost update underway	Feasibility complete	Feasibility complete	Pre-FEED underway	Pre-FEED underway
Estimated regulatory approval date (plant & transmission)	Q4 2023	Q4 2023	Q2 2024	Q1 2024	1H 2024	2H 2024
Earliest FID date	Q4 2023	Q4 2023	Q2 2024	Q1 2024	2H 2024	1H 2025
Earliest COD date[4]	Q4 2025	Q4 2025	Q2 2026	Q3 2025	2H 2027	1H 2028
Total installed capital cost ($ million) [1, 2, 3, 5, 6]	$750 (Class 2)	$156 (Class 3)	$660 (Class 3)	$320 (Class 4)	$875 (Class 4)	$875 (Class 4)

1 – Total installed cost estimates are classified in a manner consistent with American Association of Cost Engineering ("AACE") standards.
2 – Total installed cost numbers exclude carbon capture and sequestration for gas-fired projects. CCUS costs are estimated to be an incremental 60 to 80% of the total installed cost based on an engineering study by Gas Liquids Engineering ("GLE").
3 – None of the Company's planned power generation projects have a final design, performance projection or cost estimate, or full regulatory approval or internal or external funding. There is no assurance that the power generation projects will proceed as described or at all.
4 – If an FID decision is reached, the Company will advance the project towards an estimated Commercial Operations Date ("COD").
5 – Capital costs may increase due to the state of the current economic environment and related inflation and supply chain challenges; specific capital cost adjustments will be applied as projects progress through engineering review stages. Homestead Solar capital cost estimate updated with completion of Class 2 estimate on June 8, 2022.
6 – Capital cost estimates increased for Granum and Phoenix solar projects resulting from increased capacity due to project optimization.
7 – Regulatory and environmental applications are filed with the AEPA and AUC.

Carbon storage hubs

On October 4, 2022, the Government of Alberta awarded Kiwetinohk the right to advance planning on the Opal Carbon Hub and NGCC 2 Carbon Hub projects, representing up to an estimated 4 million tonnes/year of sequestration capacity. The next step in the process is to execute an evaluation agreement with the Province of Alberta for both projects, under which Kiwetinohk will be granted the right to conduct evaluations and testing of deep subsurface reservoirs, over a term not to exceed five years, for the purpose of determining their suitability for use for the sequestration of captured carbon dioxide.

Kiwetinohk's long term strategy is to capture 90% or more of the carbon dioxide (CO_2) associated with the Company's planned gas-fired power projects. The Company believes its Opal and NGCC 2 power projects associated with the carbon hubs it has been granted, become incrementally de-risked as Kiwetinohk will have control of the development timeline for its power projects and significant influence on the associated carbon hubs. In addition, the Company would be a manager of access to the carbon hubs for Kiwetinohk's associated power projects and other industrial players.

As part of its commercial assessment of the carbon hubs, Kiwetinohk will also begin work to determine how to offer capture, transportation and sequestration services to other CO_2 emitters and the terms of such offerings. The commercial assessment will also provide an opportunity to work with government and industry to establish a provincial CO_2 midstream policy.

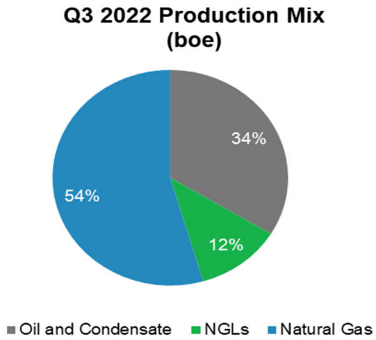
Kiwetinohk believes it will be well positioned as a primary user of its awarded carbon hubs due to its associated power projects in development today and potential future projects. The development of the carbon hubs will also provide an opportunity for third party revenue streams, for processing and sequestration capacity, as other regional players seek to reduce their carbon emissions footprint.

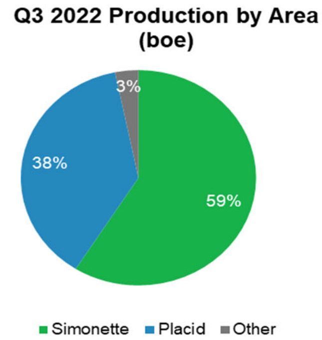
The carbon hubs that Kiwetinohk were awarded are part of the corporate development plans for the gas-fired power portfolio and have not required any incremental capital or general and administrative commitments at this time.

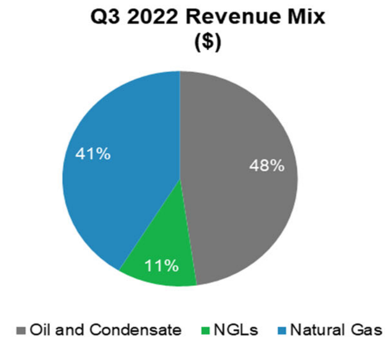
Results of operations

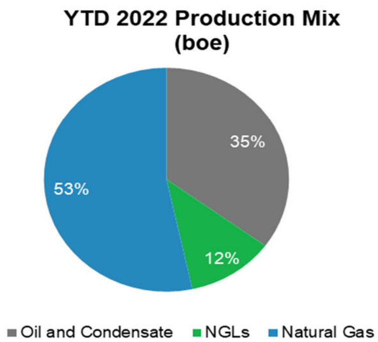
Production

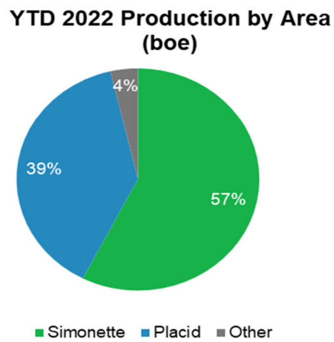
	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Oil & condensate (bbl/d)	**5,558**	4,608	**5,446**	2,854
NGLs (bbl/d)	**1,944**	1,814	**1,793**	1,048
Natural gas (Mcf/d)	**53,912**	51,817	**49,741**	30,089
Total production (boe/d)	**16,487**	15,058	**15,529**	8,918
Oil and condensate % of production	**34%**	31%	**35%**	32%
NGL % of production	**12%**	12%	**12%**	12%
Natural gas % of production	**54%**	57%	**53%**	56%
Total production volumes %	**100%**	100%	**100%**	100%

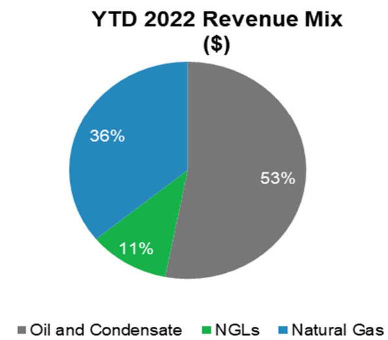












Production during the third quarter of 2022 averaged 16,487 boe/d compared to 15,058 boe/d in the third quarter of 2021. The Company's production volumes have increased as six new wells were brought on-stream during the first half of 2022. The Company's production portfolio during the third quarter of 2022 was 34% oil and condensate, 12% NGLs, and 54% natural gas, with an increase in condensate production as compared to 2021 as a result of new wells being more liquids weighted compared to historical production. On September 15, 2022 the Company completed an acquisition of additional working interest in the Placid area which contributed an estimated 140 boe/d for the third quarter.

Production during the nine months ended September 30, 2022 averaged 15,529 boe/d compared to 8,918 boe/d in the comparative period of 2021. Production increased significantly year over year reflecting a full period of results from the Simonette assets acquired in April 2021, and the consolidation of Distinction operations in April 2021, as well as incremental production generated through the Company's development program. During the first nine months of 2022, the Simonette and Placid areas contributed 57% and 39% of production, respectively. The Simonette and Placid assets both deliver high liquids content natural gas with the Company having an average total liquids yield of approximately 145 bbls/MMcf during the quarter.

Benchmark and realized prices

	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Liquid benchmark prices				
WTI (US$/bbl)	**91.55**	70.56	**98.09**	64.82
WTI (CDN$/bbl)	**119.46**	88.93	**125.80**	81.10
Edmonton Light (CDN$/bbl)	**116.60**	83.04	**123.41**	75.63
WCS Hardisty (CDN$/bbl)	**101.75**	72.62	**104.49**	65.73
Natural gas benchmark prices				
Henry Hub (US$/MMBtu)	**8.20**	4.01	**6.77**	3.18
Chicago City Gate MI (US$/MMBtu)	**7.86**	3.86	**6.86**	3.07
Chicago City Gate DI (US$/MMBtu)	**7.38**	4.10	**6.33**	5.39
AECO 5A (CDN$/GJ)	**3.95**	3.41	**5.10**	3.11
AECO 7A (CDN$/GJ)	**5.50**	3.36	**5.27**	2.94
Foreign exchange rates (CAD/USD)	**0.77**	0.79	**0.78**	0.80

	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Realized prices				
Oil & condensate ($/bbl)	**114.48**	80.61	**121.48**	78.14
NGLs ($/bbl)	**75.50**	49.74	**76.68**	46.02
Natural gas ($/Mcf)	**10.20**	5.12	**9.01**	4.67
Total ($/boe)	**80.86**	48.29	**80.31**	46.17

WTI benchmark prices increased significantly in the three and nine months ended September 30, 2022 over the comparative periods of 2021. The increase is primarily a result of Russia's invasion of Ukraine and related supply sanctions, which have continued to limit supply to the market, aided by 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") prior to some supply increases being announced for July and August 2022. This, along with increased capital discipline amongst producers has resulted in global crude oil demand outpacing supply during the nine-months of 2022.

Edmonton Light benchmark pricing experienced significant increases in 2022 compared to 2021, generally driven by the same factors as WTI prices. For the three and nine months ended September 30, 2022, Edmonton Light benchmark prices averaged $116.60 and $123.41 per barrel compared to $83.04 and $75.63 CDN$/bbl in 2021, respectively.

Natural gas prices also increased significantly in the first three and nine months ended September 30, 2022 when compared to the prior year due to low storage levels, flat production levels and an increase in US LNG exports, all of which have continued to drive an increase in pricing. At September 30, 2022, natural gas prices had fallen from their highs in mid-summer due to an outage at the Freeport LNG terminal and Lower-48 storage levels recovering closer to five-year averages. The Chicago City Gate monthly index benchmark for natural gas for the three and nine months ended September 30, 2022 increased to US $7.38/MMBtu and US $6.33/MMBtu, respectively, compared to US $4.10/MMBtu and US $5.39/MMBtu during 2021. The Chicago City Gate daily index benchmark for natural gas for the three and nine months ended September 30, 2022 saw similar strength in pricing in comparison to 2021 as demand continued to outpace supply in that marketplace alongside strong NYMEX Henry Hub benchmark pricing.

In contrast, the AECO market in Alberta experienced significant volatility during the three months ended September 30, 2022, due to pipeline maintenance on the NGTL system and growing storage, resulting in a significantly larger differential between the Chicago and Alberta sales points in the third quarter of 2022. As AECO prices saw significant declines, this resulted in the differential between Henry Hub and AECO widening significantly during the three and nine months ended September 30, 2022, when compared to the comparable periods in 2021.

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 through both the Simonette and Distinction transactions. Kiwetinohk is currently the third largest shipper on Alliance Pipelines and uniquely positioned with approximately 90% of its natural gas anticipated to be sold into the strong Chicago market for the remainder of the year.

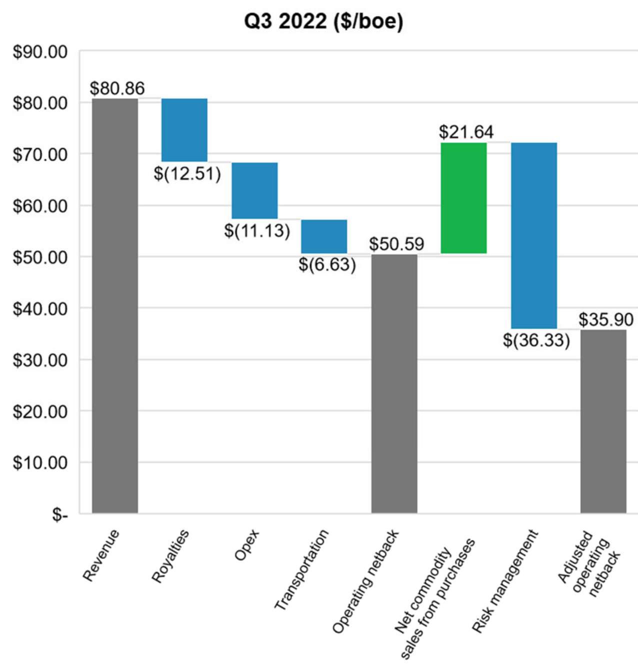
Kiwetinohk also sells natural gas in the AECO market through the Nova Gas Transmission Ltd. ("NGTL") system. Natural gas that is sweetened (through the removal of hydrogen sulfide) at the Company's amine facility is further processed at its approximately 40% owned sweet natural gas plant ("Bigstone Sweet Plant") which is currently connected to the both the Alliance and NGTL pipeline systems.

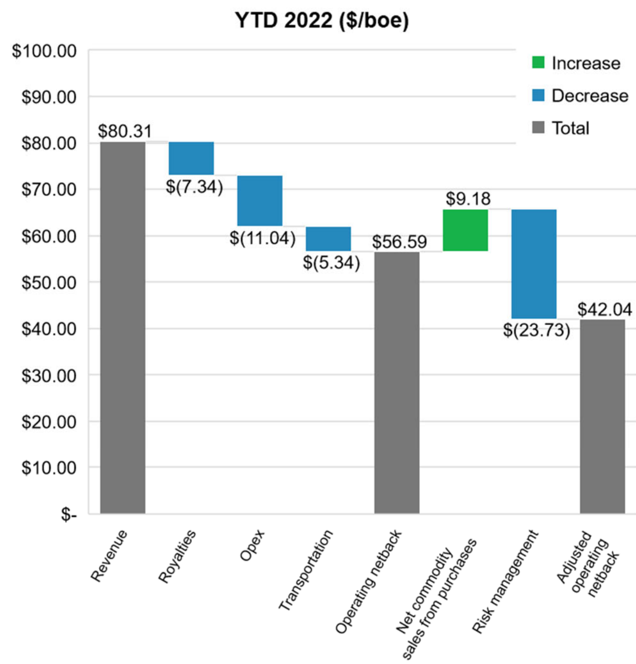
The Company has contracted for approximately 20.5 MMcf/d of transportation service on NGTL with 0.3 MMcf/d expiring in mid-2023, and a further 0.2 MMcf/d expiring at the end of Q1 2024. The remaining 20.0 MMcf/d is contracted until March 31, 2026.

Operating netback

	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Realized price ($/boe)	**80.86**	48.29	**80.31**	46.17
Royalty expenses ($/boe)	**(12.51)**	(6.49)	**(7.34)**	(4.83)
Operating expenses ($/boe)	**(11.13)**	(8.14)	**(11.04)**	(8.14)
Transportation expenses ($/boe)	**(6.63)**	(5.72)	**(5.34)**	(5.03)
Operating netback [1]($/boe)	**50.59**	27.95	**56.59**	28.17
Net commodity sales from purchases [1] ($/boe)	**21.64**	3.71	**9.18**	1.63
Realized loss on risk management ($/boe) [1 2]	**(16.92)**	(7.61)	**(16.96)**	(7.00)
Realized loss on risk management contracts – purchases ($/boe) [1]	**(19.41)**	(4.21)	**(6.77)**	(2.35)
Adjusted operating netback [1]	**35.90**	19.84	**42.04**	20.45
Total production (boe/d)	**16,487**	15,058	**15,529**	8,918

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.
2 – Realized loss on risk management contracts includes settlement of financial hedges on production and foreign exchange, with losses on contracts associated with purchases presented separately.





Operating netback during the quarter ended September 30, 2022 was $50.59/boe compared to $27.95/boe in the same period in 2021. For the nine month period ended September 30, 2022, operating netback was $56.59/boe compared to $28.17/boe during 2021. Increases were primarily driven by a significant increase in average realized pricing with increases of $32.57/boe and $34.14/boe realized during the three and nine month periods respectively relative to the comparable periods in 2021. The increase in realized pricing led to higher royalty expenses with the impact in the nine month period partially offset by a recovery on finalizing the Company's 2021 gas cost allowance calculation during the second quarter. Operating expenses increased for the three and nine month periods as a result of the timing of new production additions, operating costs incurred to complete well workovers, other costs to optimize production and the impact of inflation. Transportation costs increased as the Company flowed a larger proportion of natural gas to the higher netback Chicago market and incurred incremental costs as a result of NGL production exceeding firm commitments with additional volumes transported at a higher cost posted rate.

Adjusted operating netback was $35.90/boe during the quarter ended September 30, 2022 and $42.04/boe during the nine month period. The Company incurred realized losses on risk management contracts of $36.33/boe and $23.73/boe for the three and nine month periods, respectively, which partially offset increases in realized pricing given a portion of produced and purchased volumes were hedged to manage price volatility and ensure predictable cash flows during a period of significant capital expenditures and growth.

Revenue

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Oil & condensate	**58,532**	34,172	**180,603**	60,885
NGLs	**13,501**	8,300	**37,528**	13,171
Natural gas	**50,611**	24,426	**122,310**	38,345
Total commodity sales from production	**122,644**	66,898	**340,441**	112,401

During the three and nine months ended September 30, 2022, the Company realized a significant increase in revenues relative to comparable periods in 2021 as a result of increased production levels and a significant increase in benchmark pricing, period over period. During the three month period, revenue increased to $122.6 million, an increase of $55.7 million from the third quarter of 2021. During the nine month period, revenue increased to $340.4 million as compared to $112.4 million in 2021.

Net commodity sales from purchases

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Commodity sales from purchases	**77,623**	38,349	**220,650**	56,119
Commodity purchases, transportation and other	**(44,810)**	(33,205)	**(181,755)**	(52,142)
Net commodity sales from purchases [1]	**32,813**	5,144	**38,895**	3,977
Realized hedging loss on purchases[1]	**(29,435)**	(5,832)	**(28,699)**	(5,720)
Net commodity sales from purchases after hedging[1]	**3,378**	(688)	**10,196**	(1,743)
$/boe – before hedging	**21.64**	3.71	**9.18**	1.63
$/boe – after hedging	**2.23**	(0.50)	**2.41**	(0.72)

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.

In order to mitigate the cost of transportation service in excess of current production 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 three-and nine-month periods after proprietary field production and temporarily assigned volumes. The Company also enters into risk management contracts associated with purchased natural gas volumes for resale to secure the pricing difference between the Alberta and Chicago sales points. This strategy has resulted in positive net commodity sales from purchases after hedging of $10.2 million for the first nine months of 2022 while allowing the Company to meet its excess transportation commitments on the Alliance pipeline. During the quarter significant volatility in Alberta-based natural gas prices resulted in periods of large price differences between Chicago and Alberta markets which resulted in larger realized hedging losses on the Company’s natural gas purchases which served to partially offset net commodity sales from purchases as would be expected under this strategy.

The Company does not seek to speculate on price movements for purchased natural gas volumes for resale and manages its excess pipeline commitments by securing third party natural gas volumes. Price differentials between the Chicago and Alberta markets and the associated market risk is monitored on purchased volumes and managed by securing pricing through periodic risk management contracts in accordance with Board approved risk management guidelines.

In the three and nine months ended September 30, 2022, the Company realized net commodity sales from purchases of $32.8 million and $38.9 million on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system. Including the offsetting impact of risk management contracts, the Company realized gains of $3.4 million and $10.2 million for the three and nine months ended September 30, 2022, respectively.

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 and significant capital development program. 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.

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Risk management:				
Unrealized gain (loss)	**26,266**	(35,719)	**(18,439)**	(62,504)
Realized loss	**(55,108)**	(16,372)	**(100,597)**	(22,759)
Total loss on risk management	**(28,842)**	(52,091)	**(119,036)**	(85,263)
Unrealized gain (loss) ($/boe)	**17.32**	(25.78)	**(4.35)**	(25.67)
Realized loss ($/boe)	**(36.33)**	(11.82)	**(23.73)**	(9.35)

The following table reconciles the components of the realized loss on risk management contracts:

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Realized gain (loss) on production	**(25,190)**	(10,000)	**(72,339)**	(16,525)
Realized gain (loss) on purchases	**(29,435)**	(5,832)	**(28,699)**	(5,720)
Realized gain (loss) on foreign exchange	**(483)**	(540)	**441**	(514)
Total realized gain (loss)	**(55,108)**	(16,372)	**(100,597)**	(22,759)
Realized gain (loss) on production ($/boe)	**(16.60)**	(7.22)	**(17.06)**	(6.79)
Realized gain (loss) on purchases ($/boe)	**(19.41)**	(4.21)	**(6.77)**	(2.35)
Realized gain (loss) on foreign exchange ($/boe)	**(0.32)**	(0.39)	**0.10**	(0.21)

For the three and nine months ended September 30, 2022, the Company recorded realized losses on risk management contracts of $55.1 million and $100.6 million, respectively. Approximately 53% and 29% was related to natural gas volumes purchased for resale required to meet pipeline commitments in excess of the Company's production needs, where the Company hedges price differences between Chicago and Alberta markets at the time of contracting third party natural gas purchases.

Losses on production hedges in the three and nine month periods ended September 30, 2022 have increased relative to 2021 as a result of higher benchmark pricing relative to hedged levels. When compared to the first half of the year, losses related to volumes purchased to fill pipeline capacity grew significantly as a result of the widening of the differential between Chicago and AECO prices (see – Net commodity sales from purchases).

The unrealized gain on risk management of $26.3 million during the third quarter of 2022 and unrealized loss of $18.4 million for the nine months ended September 30, 2022, represent 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 condensed consolidated interim 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 commodity risk management contracts outstanding at September 30, 2022:

Type		Q4 2022	2023	2024
Crude oil				
WTI fixed price	bbl/d	1,750	1,613	500
WTI buy put	bbl/d	2,883	1,375	-
WTI sell call	bbl/d	1,883	1,063	-
WTI swap average	US$/bbl	$74.58	$68.79	$70.62
WTI buy put average	US$/bbl	$62.26	$83.81	-
WTI sell call average	US$/bbl	$56.05	$100.63	-
Natural gas [2]				
NYMEX Henry Hub fixed price	MMBtu/d	15,350	11,375	2,500
NYMEX Henry Hub buy put	MMBtu/d	24,500	18,333	-
NYMEX Henry Hub sell call	MMBtu/d	19,500	6,458	-
NGI Chicago basis to NYMEX Henry Hub	MMBtu/d	21,283	10,625	-
NYMEX Henry Hub fixed price average	US$/MMBtu	$2.64	$3.35	$3.23
NYMEX Henry Hub buy put average	US$/MMBtu	$6.31	$5.05	-
NYMEX Henry Hub sell call average	US$/MMBtu	$8.78	$6.39	-
NGI Chicago basis to NYMEX Henry Hub average	US$/MMBtu	$0.01	$0.05	-
AECO 5A fixed price	GJ/d	2,025	-	-
AECO 5A average	C$/GJ	$2.09	-	-
Natural gas transportation [2,3]				
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	43,333	20,833	-
Sell GDD Chicago basis (to NYMEX Henry Hub)	MMBtu/d	(43,333)	(20,833)	-
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	($1.27)	($1.28)	-
GDD Chicago basis (to NYMEX Henry Hub) average	US$/MMBtu	$0.03	$0.10	-

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 has the following foreign exchange risk management contracts outstanding at September 30, 2022:

Type		Q4 2022	2023	2024
Foreign exchange				
Sell USD CAD (monthly average)	US$	$1.7 MM	-	-
USD CAD buy put	US$	$5.8 MM	$0.6 MM	-
USD CAD sell call	US$	$5.8 MM	$0.6 MM	-
USD CAD fixed sell rate		$1.29	-	-
USD CAD put rate		$1.26	$1.26	-
USD CAD call rate		$1.30	$1.30	-

1 – Prices per unit and volumes per day are represented at the average amounts for the period.

The Company's total risk management contract liability outstanding is as follows:

$ 000's	September 30, 2022	December 31, 2021
Short term risk management asset	**652**	-
Short term risk management liability	**(44,212)**	(26,115)
Long term risk management liability	**(3,682)**	(2,688)
Total risk management contracts liability	**(47,242)**	(28,803)

$ 000's	September 30, 2022	December 31, 2021
Liability on produced volumes	**(35,632)**	(28,529)
Liability on purchased volumes	**(9,842)**	(1,936)
Asset (liability) on foreign exchange contracts	**(1,768)**	1,662
Total risk management liability	**(47,242)**	(28,803)

Subsequent to September 30, 2022, the Company entered into the following risk management contracts:

Type	Unit	Q4 2022	2023	2024
Crude oil				
WTI buy put	bbl/d	-	250	250
WTI sell call	bbl/d	-	250	250
WTI buy put average	US$/bbl	-	$70.00	$65.00
WTI sell call average	US$/bbl	-	$88.00	$77.80

1 – Prices per unit and volumes per day are represented at the average amounts for the period.

Royalty expense

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Royalty expense	**18,973**	8,987	**31,131**	11,760
As a % of revenue	**16%**	13%	**9%**	10%
$/boe	**12.51**	6.49	**7.34**	4.83

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties in the three and nine months ended September 30, 2022 increased to $18.9 million and $31.1 million as compared to $9.0 million and $11.8 million in the comparative periods of 2021. The Company continues to benefit from Alberta's drilling and completion cost allowance program, which provides a 5% royalty rate on a well's initial production until the well's cumulative revenue, from all hydrocarbon products, equals a maximum threshold. During the third quarter royalties as a percentage of revenue increased to 16% as older wells reverted from this reduced royalty framework to significantly higher base royalty rates.

During the nine months ended September 30, 2022, royalties as a percentage of revenues decreased to 9% as a result of a $8.2 million credit received in the second quarter of 2022 in relation to finalizing the Company's 2021 gas cost allowance ("GCA") calculation. This recovery served to offset increases to royalties resulting from higher benchmark pricing and production during the nine-month period.

Operating expenses

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Operating expenses	**16,873**	11,271	**46,805**	19,812
$/boe	**11.13**	8.14	**11.04**	8.14

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 during the three and nine months ended September 30, 2022, increased to $16.9 million and $46.8 million, respectively, due to increased production volumes and higher levels of activity. In addition, during the three and nine month periods ended September 30, 2022, the Company incurred higher costs as a result workovers completed on older wells and other incremental costs to optimize production with the impact amplified by inflationary cost pressures. During the nine month period, the Company also incurred incremental operating costs related to facility turnaround costs, required road maintenance and a decision to use temporary flowback equipment ahead of permanent tie-in operations to accelerate profitable new well production during the second quarter.

On a per boe basis, operating costs increased by $2.99/boe in the third quarter of 2022 to $11.13/boe compared to $8.14/boe in the third quarter of 2021. For the nine month period, operating costs increased by $2.90/boe from the prior year period to $11.04/boe. Operating costs per boe increased as a result of the timing of new well additions, incremental costs noted above and inflationary cost pressures in the field as the oil and gas industry responded to increased levels of activity throughout the Western Canadian basin to take advantage of strong commodity pricing.

Transportation expenses

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Transportation expenses	**10,060**	7,920	**22,628**	12,254
$/boe	**6.63**	5.72	**5.34**	5.03

Transportation expenses are incurred to deliver oil and natural gas commodities from the Company's production to the delivery point of sale. The Company 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. Transportation expense increased as the Company flowed a larger proportion of natural gas to the higher cost Chicago market and incurred incremental costs as a result of NGL production exceeding firm commitments with additional volumes transported at a higher cost posted rate. For the nine month period, transportation costs increased further as a result of higher production.

Adjusted funds flow from (used in) operations

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Cash flow from (used in) operating activities	**91,710**	29,643	**155,822**	10,311
Net change in non-cash working capital from operating activities	**(42,916)**	(8,487)	**5,042**	9,800
Asset retirement obligation expenditures	**423**	-	**1,587**	-
Restructuring costs	**-**	1,617	**-**	2,449
Acquisition costs	**125**	1,048	**125**	6,506
Settlement costs	**-**	-	**-**	10,000
Adjusted funds flow from (used in) operations [1]	**49,342**	23,821	**162,576**	39,066
$/boe	**32.53**	17.19	**38.35**	16.05

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 significantly during 2022 relative to the prior year comparable periods, to $49.3 million and $162.6 million for the three and nine months ended September 30, 2022, respectively. The increase is a result of stronger commodity prices and higher production achieved through the Simonette and Distinction acquisitions and the Company's drilling program. The Company's cash flow from operating activities was $91.7 million and $155.8 million for the three and nine months ended September 30, 2022. Cash flow from (used in) operating activities has been adjusted for the net change in non-cash working capital from operating activities, asset retirement obligation expenditures, restructuring costs associated with Distinction's *Companies' Creditors Arrangement Act* ("CCAA") process, acquisition costs to complete acquisitions and one-time settlement costs to terminate certain carried interest rights and obligations. Non-cash working capital was a significant source of cash during the three months ended September 30, 2022 as average receivable balances declined with lower benchmark pricing as compared to the second quarter and accounts payable increased due to significant hedging losses and higher royalties payable.

Free funds flow (deficiency) from operations

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Adjusted funds flow from (used in) operations [1]	**49,342**	23,821	**162,576**	39,066
Capital expenditures (excluding acquisitions and dispositions)	**(60,461)**	(14,753)	**(167,021)**	(18,941)
Free funds flow (deficiency) from operations [1]	**(11,119)**	9,068	**(4,445)**	20,125
$/boe	**(7.33)**	6.54	**(1.05)**	8.27

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 three and nine-month periods ended September 30, 2022 was $11.1 million and $4.4 million relative to free funds flow of $9.1 million and $20.1 million in the comparative periods of 2021. The Company had significantly higher capital expenditures during 2022 as the Company continues to develop the Fox Creek core area. The Company has been able to manage capital spending through funds flow from operations as a result of continued strength in the commodity price environment and available credit facilities.

General and administrative ("G&A") expenses

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Gross G&A expenses	**4,187**	3,702	**14,806**	8,876
Less capitalized G&A	**(652)**	(877)	**(1,788)**	(1,262)
G&A Expenses	**3,535**	2,825	**13,018**	7,614
$/boe	**2.33**	2.04	**3.07**	3.13

Gross G&A expenses increased to $4.2 million and $14.8 million during the three and nine months ended September 30, 2022 as compared to $3.7 million and $8.9 million in the comparable periods of 2021. The increase is primarily attributable to the significant growth in the Company that occurred in the second half of 2021 and into 2022. This included additional employees to support and execute on the Company's strategy and additional costs associated with operating as a public company. A portion of G&A expense continues to be directly related to business development initiatives in the Green Energy segment around developing renewable and natural gas-fired power generation projects with a vision of also incorporating carbon capture technology and hydrogen production.

Share-based compensation expenses

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Share-based compensation expenses	**2,277**	2,486	**8,275**	10,156
$/boe	**1.50**	1.79	**1.95**	4.17

Share-based compensation is the non-cash compensation expense recognized for stock options, performance warrants, and deferred share units. 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. Compensation expense related to deferred share units was calculated using the fair value method based on the trading price of the Company's shares at the end of each reporting period with changes in fair value recognized as share based compensation expense.

Share-based compensation was $2.3 million and $8.3 million for the three and nine months ended September 30, 2022 compared to $3.7 million and $7.7 million in the comparable prior year periods.

Finance costs

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Interest and bank charges	**2,313**	961	**4,791**	1,551
Accretion of asset retirement obligations	**697**	38	**1,570**	212
Interest on lease obligations	**214**	51	**230**	51
Deferred financing amortization	**323**	334	**969**	607
Unrealized loss (gain) on foreign exchange	**(1,881)**	-	**(1,871)**	-
Total finance costs	**1,666**	1,384	**5,689**	2,421
$/boe	**1.10**	1.00	**1.34**	0.99

The Company has a $375 million senior secured extendible revolving facility (the "Credit Facility") with a syndicate of banks. As at September 30, 2022 the Company had drawn $102.1 million on the facility (September 30, 2021 - $34.2 million), net of deferred financing charges. The increase in financing costs for the three and nine-month periods ended September 30, 2022 is associated with higher average debt levels outstanding and higher interest rates during the periods.

Depreciation and depletion

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Depreciation	**431**	257	**917**	566
Depletion	**17,984**	11,953	**47,150**	17,495
Total depreciation and depletion	**18,415**	12,210	**48,067**	18,061
$/boe	**12.14**	8.81	**11.34**	7.42

Increases in depletion for the three and nine-month periods ended September 30, 2022 are attributable to increases in the Company's depletable base associated with the 2021 acquisitions and a significant capital development plan in subsequent quarters and a higher production volume over the comparative periods of 2021. The Company recognized depletion of $18.0 million and $47.2 million for the three and nine-month periods ended September 30, 2022 (2021 - $12.0 million and $17.5 million respectively).

Exploration and evaluation ("E&E") expenses

$000s	Q3 2022	Q3 2021	YTD 2022	YTD 2021
Depletion	**-**	578	**1,216**	4,550
Impairment	**-**	1,400	**6,367**	47,461
Other	**80**	-	**747**	3,077
Total E&E expenses	**80**	1,978	**8,330**	55,088
$/boe	**0.05**	1.43	**1.96**	22.63

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.

Following the Simonette Acquisition the Company re-prioritized its development and drilling plans to higher return undeveloped land locations in the Fox Creek Area and as a result, the Company recognized impairment in the West Central Alberta cash generating unit ("CGU") relating to near-term land expiries of $4.3 million and $6.4 million during the three and nine month periods, respectively (2021 - $24.4 million).

E&E depletion expense was previously recorded on a unit of production basis for properties that have production but have not yet been transferred to property plant and equipment. All E&E assets were transferred to PPE during the second quarter of 2022, resulting in no depletion recognized during the three months ended September 30, 2022. The Company performed an impairment assessment at the time of transfer with no impairment recognized.

Income taxes

The Company did not pay any income taxes in 2021 and does not expect to be taxable in Canada in the near future. A deferred tax asset has not been recognized at September 30, 2022 given uncertainty around future recoverability. The Company's estimated tax pools as at September 30, 2022, are as follows:

Category	Deductibility	$000's
Canadian oil and gas property expense ("COGPE")	10%	180,855
Successored COGPE	10%	1,209
Canadian development expense ("CDE")	30%	167,222
Successored CDE	30%	88,519
Canadian exploration expense ("CEE")	100%	-
Successored CEE	100%	16,686
Undepreciated capital cost ("UCC")	Primarily 25%, declining balance	92,919
Non-capital losses	100%	239,917
Share/Debt issue costs	5-year straight line	3,614
Other	Various	(1,797)
Total estimated tax pools		789,144

Asset retirement obligations

The Company's asset retirement obligations ("ARO") of $104.0 million pertain to the Company's wells and related infrastructure. 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 $35.4 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 which exceeds the minimum regulatory requirements.

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.

Select quarterly information

($000s except per share and production)	2022 Q3	2022 Q2	2022 Q1	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4
Production (average boe/d)	**16,487**	16,810	13,253	12,422	15,058	10,797	741	645
Commodity sales from production	**122,644**	137,931	79,866	70,267	66,898	42,261	3,242	2,186
Commodity sales from purchases	**77,623**	82,429	60,598	58,398	38,349	17,770	-	-
Cash flow from (used in) operating activities	**91,710**	38,780	25,332	25,509	29,643	(15,753)	(3,579)	(777)
Per share (basic) [1]	**2.08**	0.88	0.58	0.58	0.86	(0.53)	(0.19)	(0.05)
Per share (diluted) [1]	**2.05**	0.87	0.58	0.58	0.86	(0.53)	(0.19)	(0.05)
Net income (loss) [2, 3]	**55,379**	44,854	(24,552)	44,306	(34,080)[2]	13,726[3]	(46,267)	9,732
Per share (basic) [1]	**1.26**	1.02	(0.56)	1.02	(0.99)	0.47	(2.43)	0.64
Per share (diluted) [1]	**1.24**	1.01	(0.56)	1.02	(0.99)	0.47	(2.43)	0.64

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 – At December 31, 2021 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 – At December 31, 2021 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.

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 operating activities, 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 operating activities and availability on its Credit Facility will be sufficient to meet working capital requirements and fund the Company's anticipated capital program through 2022 and into 2023. As at September 30, 2022 the Company has $245.8 million available under the Credit Facility which is sufficient to cover the Company's near term commitments and contractual obligations which includes the settlement of the $67.6 million working capital deficit held at September 30, 2022.

Credit Facility

On June 13, 2022, the Company increased the consolidated Credit facility by $60.0 million to $375.0 million. The Credit Facility is comprised of an operating facility of $65.0 million and a syndicated facility of $310.0 million.

At September 30, 2022, $102.1 million (December 31, 2021- $34.7 million) (before deferred financing costs) was outstanding on the Credit Facility along with $42.2 million (December 31, 2021 - $52.3 million) in letters of credit issue to support transportation and other commitments, of which, $6.0 million has been provided for through the Export Development Canada ("EDC") facility, resulting in $36.2 million in letters of credit which reduce the available operating facility capacity.

Subsequent to September 30, 2022, the Company completed the semi-annual redetermination on the Credit Facility with no change to the borrowing base of $375 million.

$000	Credit Facility	EDC Facility	Drawn	Letters of credit	Capacity [1]
Credit Facility	375,000	15,000	102,059	42,150	**245,791**

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.

$000s	September 30, 2022	December 31, 2021
Credit facility drawn	**102,059**	34,698
Deferred financing costs	**(861)**	(1,830)
Loans and borrowings	**101,198**	32,868
Adjusted working capital deficit[1]	**24,065**	18,644
Net debt [1]	**125,263**	51,512

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.

The Credit Facility is a 364-day committed facility available on a revolving basis until May 31, 2023, at which time it may be extended at the lenders' option. If the revolving period is not extended, the undrawn portion of the Credit Facility will be cancelled and the amount outstanding would be required to be repaid at the end of the non-revolving term, being May 31, 2024. The borrowing base is determined based on the lenders' evaluation of the Company's petroleum and natural gas reserves at the time and commodity prices.

Interest payable on amounts drawn under the Credit Facility is at the prevailing bankers' acceptance rate 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.

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

EDC Credit Facilities

On February 10, 2022, Kiwetinohk entered into a $15.0 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 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. As at September 30, 2022, the Company has $9.0 million of capacity remaining under the LC Facility.

Base shelf prospectus

The Company filed a short-form base shelf prospectus ("Prospectus") in April 2022 to provide financing flexibility and additional options for quicker access to public equity and/or debt markets as it continues to pursue potential acquisition opportunities. The Prospectus provides Kiwetinohk with the ability to issue up to $500 million of securities over a period of 25 months. There are no immediate plans to raise equity, debt or other forms of financing and net proceeds from the sale of any securities issued under the Prospectus could have a wide range of uses including to complete asset or corporate acquisitions, to finance potential future growth opportunities, to repay indebtedness, to finance the Company's ongoing capital program, or for other general corporate purposes.

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 (see Acquisitions – Distinction Amalgamation), Kiwetinohk issued 10.2 million common shares and acquired all of the Distinction common shares not already owned by it. 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)	3-months ended September 30, 2022	3-months ended September 30, 2021	9-months ended September 30, 2022	Year ended December 31, 2021
Weighted average shares outstanding				
Basic	**44,114**	34,322	**44,004**	31,689
Diluted	**44,795**	34,322	**44,491**	31,689
Outstanding securities				
Common shares	**44,117**	43,610	**44,117**	43,675
Stock options	**2,646**	3,217	**2,646**	3,228
Performance warrants	**7,709**	7,609	**7,709**	7,922
Capital warrants	**-**	-	**-**	-
Total diluted outstanding securities	**54,472**	54,436	**54,472**	54,825

At November 9, 2022 the Company has 44,180,014 common shares outstanding.

Commitments, contractual obligations, and provisions

$000s	2022	2023	2024	2025	2026	Thereafter
Gathering, processing and transport [1]	18.2	74.2	76.8	67.6	15.3	58.8
Natural gas purchases	30.4	64.4	-	-	-	-
Lease liabilities	-	0.5	1.8	2.1	2.2	9.9
Other	-	0.4	0.4	0.4	0.4	1.1
Risk management contracts	21.0	25.0	1.2	-	-	-
Loans and borrowings	-	-	102.1	-	-	-
Contingent payment consideration	-	11.9	-	-	-	-
Accounts payable	77.0	-	-	-	-	-
Total	146.6	176.4	182.3	70.1	17.9	69.8

1 – Gas transportation contracts include commitments on Alliance, NGTL and various NGL and condensate transportation 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.

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.

The Company currently has secured 65,000 GJ per day of gas supply (approximately 57.2 MMcf per day) from several natural gas producers through 2022 and approximately 34,000 GJ/d in 2023, 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.

Business Combinations

The following is a summary of the Company's 2021 business combinations:

$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)	-
Total purchase price	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 (as defined below) 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 with an expected payment of $10.0 million in the first quarter of 2023.

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.

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.

Related party information

For the three and nine months ended September 30, 2022, the Company incurred a total of $0.2 million and $1.3 million, respectively (September 30, 2021 – $0.9 million and $1.9 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; and
- 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.

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 the integration of the Simonette assets and Distinction, Kiwetinohk is implementing a new health and safety program that applies best practices across all operations.

Kiwetinohk is completing a thorough review of its environmental, social and governance ("ESG") risks and management strategies, and published its first ESG report concurrently with this MD&A 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. For additional information on risk factors, refer to the Company's audited financial statements as at and for the year ended December 31, 2021 and the Company's Annual Information Form ("AIF") dated March 23, 2022 available on the SEDAR website at www.sedar.com.

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 AIF.

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 in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed and reported within the time periods specified in securities legislation.

There were no changes in the Company's internal controls during the period beginning on July 1, 2022, and ending on September 30, 2022, that have materially affected, or are reasonably likely to materially affect, the Company's internal controls over financial reporting. It should be noted that a control system, including the Company's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute assurance that the objectives of the control system will be met, and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

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. There have been no material changes to the Corporation's critical accounting estimates, judgments and policies during the three and nine months ended September 30, 2022.

Financial instruments and risk management

The Company's financial instruments are classified and measured at amortized cost or fair value through profit or 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 exposure to these counterparties, the majority of which is short-term.

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 condensed consolidated interim balance sheet include 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 16 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.

The Company uses financial risk management contracts to mitigate its exposure to the potential adverse impact of commodity price and exchange rate volatility. The primary objective of the risk management program is to protect cash flows from base production and ensure sufficient capital and liquidity is available to pursue its ongoing growth plans and significant capital development program.

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 September 30, 2022.

Other

Management changes
Farid Shirkavand, Vice President, Power Projects, has left Kiwetinohk. We thank him for his service and wish him the best with all his future endeavors. His responsibilities will be assumed by other members of the team.

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 surplus (deficit)", "credit facility capacity", "net debt", "net debt to annualized adjusted funds flow from operations", "net commodity sales from purchases" and "net commodity sales from purchases after hedging". 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 they 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 surplus (deficit)
Adjusted working capital surplus (deficit) is comprised of current assets less current liabilities excluding risk management contracts. Adjusted working capital 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	September 30, 2022	December 31, 2021
Current assets	**71,897**	47,557
Current liabilities	**(139,522)**	(92,316)
Working capital deficit	**(67,625)**	(44,759)
Short term risk management contracts net liability	**43,560**	26,115
Adjusted working capital surplus (deficit)	**(24,065)**	(18,644)

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 and net debt to annualized adjusted funds flow from operations
Net debt is comprised of loans and borrowings plus adjusted working capital surplus (deficit) and represents the Company's net financing obligations. Net debt 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. Net debt to annualized 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 annualized adjusted funds flow is calculated as net debt divided by the trailing four quarter adjusted funds flow from operations.

$000s	September 30, 2022	December 31, 2021
Loans and borrowings	**101,198**	32,868
Adjusted working capital deficit	**24,065**	18,644
Net debt	**125,263**	51,512
Net debt to annualized adjusted funds flow from operations	**0.65**	0.74

Net commodity sales from purchases and Net commodity sales from purchases after hedging

Commodity sales from purchases and commodity purchases, transportation and other is revenue from the sale of purchased natural gas less associated commodity purchases, transportation expense and related marketing fees. Net commodity sales from purchases is used as a key measure of how the Company is managing its take or pay pipeline commitments. The Company also enters into risk management contracts associated with marketing activities to protect the basis differential between the Alberta and Chicago sales points related to net commodity sales from purchase. Net commodity sales from purchases after hedging includes the impact of these basis differential contracts.

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", “may” 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;
- the amount of the Company’s natural gas to be sold on the Chicago market and the timing thereof;
- anticipated North American natural gas prices;
- the particulars for a potential financing including the timing, occurrence and potential financial partners;
- timing for the Company’s Homestead Solar, Opal Firm Renewable and Solar 3 projects to reach FID and COD;
- submission of applications and receipt of certain regulatory approvals, including AUC power plant approvals and AEPA industrial approval thereof;
- anticipated grid capacity for green energy projects;
- expected length of third party pipeline outages;
- development, evaluation and permitting of the Company’s solar and gas-fired power portfolio;
- the Company’s goal to capture 90% of carbon associated with its gas-fired power projects;
- anticipated production increases into the first quarter of 2023;
- perceived benefits of the Company’s hub projects;
- 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;
- future taxes payable by the Company;
- anticipated contingent payments from acquisitions and the timing thereof;
- the timing and costs of the Company's capital projects, including, but not limited to, drilling, production and completion of certain wells;
- the anticipated outcomes of the Company’s capital program;
- expectations regarding the Company’s working capital requirements and funding of the Company’s capital program;
- anticipated well production;
- asset retirement obligations;
- the Company’s updated 2022 financial and operational guidance

- operating and capital costs in 2022;
- sufficiency of funds to meet the Company's working capital requirements and anticipated drilling 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;
- the anticipated staffing levels required to achieve the Company's current plans;
- the Company's operational, financial and capital guidance; 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, including drilling and completion of certain wells;
- costs to abandon wells or reclaim property;
- the impact of increasing competition;
- general business, economic and market conditions
- 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;
- the ability of the Company to obtain the required capital to finance its exploration, development and other operations and meet its commitments and financial obligations;
- the ability of the Company to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms and the capacity and reliability of facilities;
- anticipated timelines and budgets being met in respect of drilling and completions programs and other operations;
- the impact of war, hostilities, civil insurrection, pandemics (including COVID-19), instability and political and economic conditions (including the ongoing Russian-Ukrainian conflict) on the Company; 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:

- those risks set out in the AIF under "Risk Factors";
- the ability of management to execute its business plan;
- general economic and business conditions;

- risks of war, hostilities, civil insurrection, pandemics (including COVID-19), instability and political and economic conditions (including the ongoing Russian-Ukranian conflict) in or affecting 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;
- risks relating to regulatory approvals and financing;
- 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;
- risks associated with rising capital costs and timing of project completion;
- fluctuations in commodity and power prices, foreign currency exchange rates and interest rates;
- inflation and increased pricing and costs for services, personnel and other items;
- 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;
- the ability to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms;
- processing, pipeline and fractionation infrastructure outages, disruptions and constraints;
- financial risks affecting the value of the Company's investments; and
- other risks and uncertainties described elsewhere in this document and in Kiwetinohk's other filings with Canadian securities authorities.

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 adjusted funds flow from operations and net debt to adjusted funds flow from operations. 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. The Company 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
$/Mcf	dollars per thousand cubic feet
AECO	the daily average benchmark price for natural gas at the physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
AESO	Alberta Electric Systems Operator
AEPA	Alberta Environment and Protected Areas
AIF	Annual Information Form
AUC	Alberta Utilities Commission
bbl(s)	barrel(s)
bbl/d	barrels per day
boe	barrel of oil equivalent, including crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe per six Mcf of natural gas)
boe/d	barrel of oil equivalent per day
CCUS	Carbon Capture Utilization and Storage
COD	Commercial Operations Date
DI	daily index
EBITDA	earnings before interest, income taxes, depreciation, depletion, and amortization
E&E	exploration and evaluation
FEED	Front End Engineers and Design
FID	Final Investment Decision
GJ	gigajoule
GJ/d	gigajoule per day
Henry Hub	the daily average benchmark price for natural gas at the distribution hub on the natural gas pipeline system in Erath, Louisiana
LNG	Liquified natural gas
mbbls	thousand barrels
MMboe	million barrels of oil equivalent
Mcf	thousand cubic feet
Mcf/d	thousand cubic standard feet per day
MI	monthly index
MMcf/d	million cubic feet per day
MMBtu	one million British Thermal Units (BTU) is a measure of the energy content in gas
MMBtu/d	one million British thermal units per day
MW	one million watts
MW.h	electrical energy of one million watts acting for one hour
NGCC	Natural Gas Combined Cycle
NGLs	natural gas liquids, which includes butane, propane, and ethane
US$/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

Corporate Head Office

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1700, 250 2 St SW
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T2P OC1

Bankers

Bank of Montreal
ATB Financial
National Bank of Canada
Royal Bank of Canada
Bank of Nova Scotia
Business Development Bank of Canada

Auditor

Deloitte LLP
Calgary, AB

Board of Directors

Kevin Brown
Board Chair

Beth Reimer-Heck
Lead Director

Judith Athaide
Director

Pat Carlson
Director and Chief Executive Officer

Leland Corbett
Director

Nancy Lever
Director

Kaush Rakhit
Director

Steve Sinclair
Director

John Whelen
Director

Reserve Engineers

McDaniel & Associates Consultants Ltd.
Calgary, AB

Legal Counsel

Stikeman Elliott LLP
Norton Rose Fulbright Canada LLP
Calgary, AB

Transfer Agent

Computershare
Calgary, AB

Stock Symbol

KEC
Toronto Stock Exchange