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 six months ended June 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 six months ended June 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 August 10, 2022.

Overview of business

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

Upstream

The Upstream business unit is involved in the acquisition, exploration and production of petroleum and natural gas reserves in Western Canada, with a focus on profitable early to mid-life liquids-rich natural gas properties that are expected to offer highly competitive economic resource potential. In 2021, the Company completed acquisitions of attractive upstream assets and associated infrastructure. These assets consist of high-netback, liquids-rich natural gas production with development upside and substantial spare processing capacity from owned infrastructure. These upstream assets provide a foundational base for the Company to pursue and develop energy transition opportunities.

Green energy

The Green Energy business unit is pursuing greenfield and/or brownfield development of a diversified Alberta-based power generation project portfolio that includes clean, efficient, and reliable natural gas-fired power with carbon capture and sequestration and renewable power sources, including solar and wind. Development work has included preparation of preliminary designs, environmental studies, permitting, consultation, Alberta Electric System Operator ("AESO") stage reviews and studies, pre-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 low-cost energy and provide downstream markets for integration of the Company's future gas production, allowing it to capture a larger portion of the hydrocarbons value chain.

Financial and operating results

	Q2 2022	Q1 2022	Q2 2021	YTD 2022	YTD 2021
Sales volumes					
Condensate (bbl/d)	**5,673**	3,475	3,096	**4,581**	1,595
Light oil (bbl/d)	**718**	876	331	**797**	337
Heavy oil (bbl/d)	**10**	13	29	**11**	31
NGLs (bbl/d)	**1,870**	1,561	1,220	**1,716**	659
Natural gas (Mcf/d)	**51,232**	43,970	36,723	**47,621**	19,045
Total (boe/d)	**16,810**	13,253	10,797	**15,042**	5,797
Oil and condensate % of production	**38%**	33%	32%	**35%**	34%
NGL % of production	**11%**	12%	11%	**11%**	11%
Natural gas % of production	**51%**	55%	57%	**54%**	55%
Realized prices					
Condensate ($/bbl)	**131.33**	115.77	76.60	**125.46**	76.63
Light oil ($/bbl))	**133.46**	115.85	75.61	**123.83**	70.35
Heavy oil ($/bbl)	**107.25**	85.83	57.85	**95.30**	52.80
NGLs ($/bbl)	**86.71**	66.03	42.04	**77.36**	40.82
Natural gas ($/Mcf)	**9.98**	6.35	4.06	**8.32**	4.04
Total ($/boe)	**90.17**	66.96	43.01	**80.00**	43.37
Royalty expense ($/boe)	**(2.69)**	(6.74)	(2.60)	**(4.47)**	(2.64)
Operating expenses ($/boe)	**(12.11)**	(9.56)	(8.10)	**(10.99)**	(8.14)
Transportation expenses ($/boe)	**(4.67)**	(4.55)	(4.36)	**(4.62)**	(4.13)
Operating netback [1] ($/boe)	**70.70**	46.11	27.95	**59.92**	28.46
Net commodity sales from purchases ($/boe) [1]	**3.58**	0.50	(1.19)	**2.23**	(1.11)
Realized loss on risk management ($/boe) [4]	**(21.09)**	(11.09)	(3.42)	**(16.71)**	(6.09)
Adjusted operating netback [1]	**53.19**	35.52	23.34	**45.44**	16.13
Financial results ($000s, except per share amounts)					
Commodity sales from production	**137,931**	79,866	42,261	**217,797**	45,503
Net commodity sales from purchases (loss) [1]	**5,486**	596	(1,167)	**6,082**	(1,167)
Cash flow from (used in) operating activities	**38,780**	25,332	(15,753)	**64,112**	(19,332)
Adjusted funds flow from (used in) operations [1]	**76,232**	37,002	17,905	**113,234**	15,245
Per share basic [2,3]	**1.73**	0.84	0.61	**2.58**	0.63
Per share diluted [2,3]	**1.71**	0.84	0.61	**2.55**	0.63
Net debt to annualized adjusted funds flow from operations [1]	**0.33**	0.66	2.92	**0.33**	2.92
Free funds flow (deficiency) from operations (excluding acquisitions/dispositions) [1]	**23,884**	(17,210)	14,035	**6,674**	19,433
Net income (loss)	**44,854**	(24,552)	3,915	**20,302**	(42,352)
Per share basic [2,3]	**1.02**	(0.56)	0.47	**0.46**	(1.34)
Per share diluted [2,3]	**1.01**	(0.56)	0.47	**0.46**	(1.34)
Capital expenditures prior to acquisitions/ (dispositions)	**52,348**	54,212	3,870	**106,560**	4,188
Acquisitions (dispositions)	**(1,620)**	(238)	282,414	**(1,858)**	282,414
Total capital expenditures	**50,728**	53,974	286,284	**104,702**	286,602
Balance sheet ($000s, except share amounts)					
Total assets	**744,454**	662,245	572,401	**744,454**	572,401
Long-term liabilities	**180,619**	145,549	142,838	**180,619**	142,838
Net debt (surplus) [1]	**55,027**	73,521	(42,105)	**55,027**	(42,105)
Adjusted working capital deficit (surplus) [1]	**(19,736)**	21,466	(18,139)	**(19,736)**	(18,139)
Weighted average shares outstanding [2,3]					
Basic	**44,061,471**	43,815,340	29,506,300	**43,948,511**	24,285,200
Diluted	**44,502,777**	43,815,340	29,506,300	**44,332,524**	24,285,200
Shares outstanding end of period [2]	**44,111,135**	44,042,515	33,436,900	**44,111,135**	33,436,900

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 natural gas purchases.

Quarterly Highlights

Upstream

- Record quarterly average production of 16,810 boe/d.
- Record quarterly adjusted funds flow from operations[1] of $76.2 million, or $1.71/share (diluted).
- Strong operating netback[1] of $70.70/boe before hedging ($53.19/boe after hedging).
- Sold 78% of natural gas production to strong Chicago market during the quarter with Chicago sales anticipated to increase to 90% for the second half of 2022.
- Capital spending totaled $52.3 million, predominately on upstream oil and gas development at Fox Creek.
- Net commodity sales from purchases[1] of natural gas in Q2 of $5.5 million before hedging.
- Four-well Simonette pad completed drilling in July, shortly after the end of the second quarter, with completion activity recently underway.

Green Energy

- The 400 MW Homestead Solar project entered Alberta Electric System Operator ("AESO") stage 3 on June 7, 2022; on track to secure grid capacity.
- Alberta Utilities Commission ("AUC") power plant application progressed during the quarter for the 101 MW Opal Firm Renewable project and subsequently approved on August 3, 2022.
- Financing discussions for the Homestead Solar project at an advanced stage with several potential investors.
- Expanded the Company's solar development portfolio with the acquisition of an early-stage 150 – 300 MW solar development project in central Alberta on May 18, 2022.

Financial

- Available credit facility capacity[1] of $273.6 million as at June 30, 2022.
- Gas Cost Allowance ("GCA") recovery received during the quarter was $8.2 million higher than originally accrued, significantly reducing stated royalty rates.
- Incremental operating costs of $5.5 million incurred during the quarter inflated operating costs for the quarter by $3.56/boe.
- The Company realized free funds flow from operations[1] of $23.9 million during the quarter, resulting in reduced debt quarter-over-quarter.
- Net debt to annualized adjusted funds flow from operations[1] of 0.33x at quarter end, down from 0.66x at the end of the first quarter and below corporate target of 1.0x.

[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" in this MD&A for further information and details.

Guidance

Management remains confident in the previously communicated 2022 guidance. With two quarters of results, adjustments have been made to guidance to incorporate first half actuals.

Steady performance from existing assets and the addition of six new development wells year-to-date contributed to average second quarter production rates of 16,810 boe/d, at the high end of the Company's annual production guidance. Accordingly, the company is increasing the lower end of production guidance for 2022 by 500 boe/d to a new range of 15,500-17,000 boe/d.

Royalty rates are reduced to an annual range of 10-12%, from the prior range of 11%-14%. This was driven by a larger than expected Gas Cost Allowance ("GCA") credit during the second quarter that is netted against royalties. In addition, while Alberta royalty rates are set on AECO pricing, the royalty rate paid will appear lower when measured against the higher Chicago price expected to be received by the Company on an estimated 90% of its natural gas sales in the second half of the year. Based on the mid-point of production guidance, and first half 2022 realized prices, every 1% reduction to royalty rates improves cash flows by ~$4.7 million.

General and administrative ("G&A") cost guidance increased to a range of $18-$20 million, from a prior range of $15-$18 million. The increase comes as a result of non-cash working capital adjustments from 2021 corporate acquisitions of $0.6 million ($0.23/boe), higher than forecast one-time TSX listing and reporting related expenses and slightly higher than forecast new hires required to support the Company's increased growth profile. The Company expects to benefit from improving G&A/boe costs in inverse proportion to projected production growth targets.

The following table sets out Kiwetinohk's revised and previous adjusted funds flow from operations, net debt to adjusted funds flow from operations, capital expenditures, costs and production guidance for 2022:

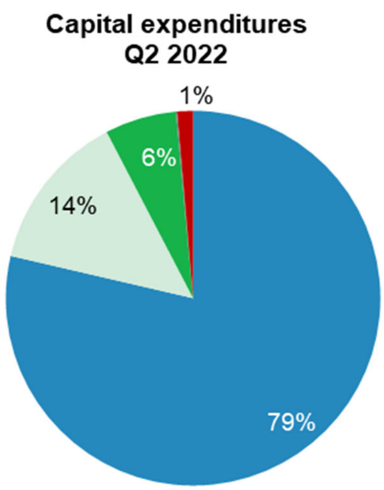
Operational & financial guidance		Revised August 10, 2022	Revised May 18, 2022	Original January 12, 2022
Production (2022 average) [1]	Mboe/d	15.5 - 17.0	15.0 - 17.0	13.0 - 15.0
Oil & liquids	Mbbl/d	7.75 - 8.50	7.5 - 8.5	6.50 - 7.50
Natural gas	MMcf/d	46.5 – 51.0	45 - 51	39 - 45
Production by market [2]	%	100%	100%	100%
Chicago	%	80% - 85%	80% - 85%	87% - 97%
AECO	%	15% - 20%	15% - 20%	3% - 13%
Financial				
Royalty rate	%	10% - 12%	11% - 14%	12% - 15%
Operating costs [1]	$/boe	$7.50 - $8.50	$7.50 - $8.50	$7.50 - $8.50
Transportation	$/boe	$5.00 - $6.00	$5.00 - $6.00	$5.00 - $6.00
Corporate G&A expense [3]	$MM	$18 - $20	$15 - $18	$15 - $18
Cash taxes	$MM	$0	$0	$0
Capital guidance	$MM	290 - 310	280 - 310	210 - 240
Upstream	$MM	275 - 290	265 - 290	200 - 220
Green Energy	$MM	15 - 20	15 - 20	10 - 20
Drilling - Fox Creek	wells	16	16	11
Duvernay	wells	15	15	10
Montney	wells	1	1	1

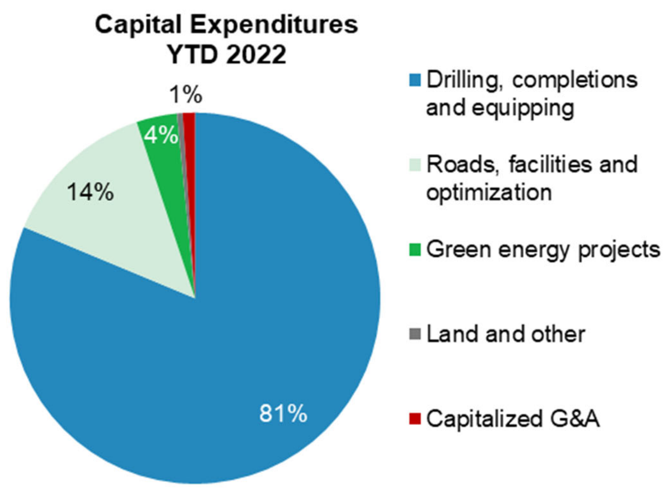
Sensitivities				
2022 Adjusted Funds Flow from Operations [4, 5, 6]				
US$70/bbl WTI & US$3.75/MMBtu HH	$MM	$210 - $230	$190 - $200	$145 - $155
US$80/bbl WTI & US$4.25/MMBtu HH	$MM	$220 - $240	$210 - $220	$165 - $175
2022 Net debt to Adjusted Funds Flow from Operations [4, 5, 6]				
US$70/bbl WTI & US$3.75/MMBtu HH	X	0.5x	0.7x	1.0x
US$80/bbl WTI & US$4.25/MMBtu HH	X	0.4x	0.6x	0.7x

1 – Operating costs include scheduled Fox Creek plant turnarounds.
2 – Chicago natural gas sales of ~90% expected for second half of 2022.
3 – Includes all G&A expenses for all divisions of the Company – Corporate, Upstream, Green Energy and Business Development.
4 - 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" within this MD&A for further information and details.
5 – H1/22 actual prices with US$70/Bbl WTI flat; US$3.75/MMBtu HH flat; US$0.79/CAD flat thereafter for remainder of 2022.
6 – H1/22 actual prices with US$80/Bbl WTI flat; US$4.25/MMBtu HH flat; US$0.81/CAD flat thereafter for remainder of 2022.

Capital expenditures

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Drilling, completions, and equipping	**41,162**	1,446	**86,606**	1,532
Roads, facilities and optimization	**7,189**	1,146	**14,525**	1,146
Green energy projects	**3,229**	874	**3,769**	874
Land and other	**62**	104	**524**	336
Capitalized G&A	**706**	300	**1,136**	300
Total capital	**52,348**	3,870	**106,560**	4,188
Acquisitions (dispositions)	**(1,620)**	282,414	**(1,858)**	282,414
Total capital and acquisitions	**50,728**	286,284	**104,702**	286,602





1 – Capital expenditures shown are before acquisitions and dispositions.

The majority of the Company's capital expenditures in 2022 prior to acquisitions/dispositions were spent on drilling, completions, and equipping with a small amount allocation to Green energy projects advancing activity towards final investment decision targets.

Drilling, completions and equipping

Steady performance from existing assets and the addition of six new development wells year-to-date contributed to average second quarter production rates of 16,810 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 two wells drilled in the first quarter are all producing through permanent facilities and performing as expected.

Four additional wells on a single pad recently completed drilling. Completion activities on this pad are expected to commence in the third quarter with the wells scheduled to come on production during the third quarter or early in the fourth quarter. The Company has also commenced drilling at a two-well pad in the northern part of Simonette offsetting the wells drilled and completed earlier this year. These wells are expected to come on production late in the year or early 2023.

Overall, Kiwetinohk's strong base production coupled with new wells coming on-line delivered solid production during the first half of the year in a strong commodity price environment further supported by superior gas pricing in Chicago and strong Canadian dollar realizations from US dollar-based sales. Steady operations and continuous learning contributed to ongoing efficiency improvements, offsetting some of the inflationary pressure seen across the industry.

Roads, facilities and optimization

During the second quarter, the Company spent $7.2 million 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 and routine maintenance projects.

Green energy development projects

Kiwetinohk continues to make significant progress in the development and permitting of its 1,950 MW solar and gas-fired power project portfolio.

The Company advanced regulatory and permitting activities for its power plant portfolio during Q2. For the 400 MW Homestead Solar project (Solar 1), Kiwetinohk progressed the AUC power plant and substation application by working with community stakeholders to resolve questions on project impacts and successfully addressed all known concerns regarding the project. Management estimates AUC regulatory approval by mid October. On June 7, 2022, the Homestead Solar project entered into the AESO Stage 3, which is the final stage prior to conditionally securing 400 MW of grid capacity for the project. Kiwetinohk also advanced the Alberta Environment and Parks (AEP) industrial application and AUC power plant and substation applications (submitted on March 31, 2022, and April 5, 2022, respectively) for the 101 MW Opal Firm Renewable project. Subsequent to Q2, Kiwetinohk received AUC power plant approval for the Opal project on August 3, 2022 and expects AEP industrial approval by year end. The 300 MW Granum solar project (Solar 2) entered AESO Stage 2 on August 5, 2022.

The Company will evaluate engineering, procurement and construction (EPC) bids as part of its due diligence process prior to reaching a final investment decision (FID) for Homestead and Opal. Kiwetinohk launched an EPC request for proposal (RFP) for Homestead on July 10, 2022, with tier one EPC companies, and bids are due in September 2022.

The Company completed the acquisition of an early-stage 150 MW (with expansion potential to 300 MW) solar development project (project Phoenix, or Solar 3) in central Alberta on May 18, 2022. Located near Red Deer, this solar project diversifies and complements Kiwetinohk's previously existing solar development portfolio located in southern Alberta. The 150 MW first phase of the Phoenix project may reach FID as early as the fourth quarter of 2023, subject to regulatory review timelines.

Kiwetinohk continues to progress development of its Natural Gas Combined Cycle (NGCC) 1 and NGCC 2 projects with pre-FEED analysis, carbon capture, use and storage (CCUS) evaluation and preliminary environmental scoping underway.

In conjunction with advancing the regulatory process, environmental permitting, engineering and capital cost updates of Kiwetinohk's power portfolio, the Company has engaged with several potential financial partners to seek external capital for the funding of its power portfolio, with the Homestead Solar project expected to be the first project financed. The Company is in discussions with several parties and estimates completion of negotiations and selection of a financial partner for Homestead, and possibly other projects, by year-end.

Prior to reaching FID for a power project development, Kiwetinohk seeks to have the following key milestones completed: stakeholder consultations, AUC power plant and transmission line approvals, AEP industrial approval, grid access, gas supply, selection of EPC and securing of financing partners. Notwithstanding significant progress made across its power project portfolio on both the regulatory and financing fronts during the first half of 2022, Kiwetinohk is updating FID and COD timing estimates for each of its projects to reflect experiences gained during the Homestead and Opal processes, specifically relating to providing additional time for public consultation and regulatory consideration. Consistent with disclosure in Kiwetinohk's Annual Information Form, updated estimates for FID and COD dates have been set out as the earliest dates such milestones are expected to be achieved, reflecting the uncertainty of pre-construction development timelines for large-scale industrial projects. Specific to Opal and the Company's NGCC projects, Kiwetinohk is seeking additional clarity regarding the federal government's evolving view on gas-fired power projects.

As at August 10, 2022 early-stage development and design factors and the status of each project 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)	400 MW	101 MW	300 MW	150 MW	500 MW	500 MW
Capacity (net to grid, AC)	400 MW	97 MW	300 MW	150 MW	460 MW	460 MW
AESO stage	3	2	2	2	2	2
Site control	Secured	Near completion	Secured	Secured	In progress	Secured
Consultation (plant/transmission)	Completed/ Underway	Completed/ Planning Underway	Planning underway	Planning underway	Planning underway	Planning underway
Regulatory / Environmental [6]	AUC plant application submitted; AEP low risk rating	AUC plant application approved; AEP application under review	AUC applications to be filed; AEP low risk rating	Work underway	Work underway	Work underway
Engineering	FEED completed; EPC request for proposals	FEED completed; detailed engineering launched	Feasibility complete	Feasibility complete	Pre-FEED underway	Pre-FEED underway

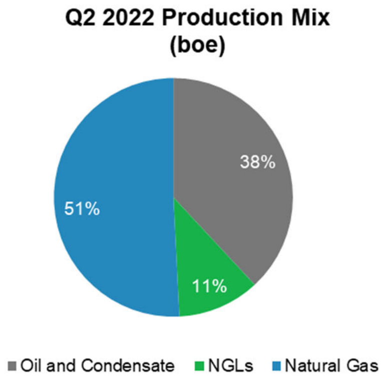
Early-stage Green Energy development, design factors & status	Homestead (Solar 1)	Opal (Firm Renewable 1)	Granum (Solar 2)	Phoenix (Solar 3)	NGCC 2	NGCC 1
Estimated regulatory approval date (plant & transmission)	Q1 2023	Q2 2023	Q4 2023	Q4 2023	1H 2024	2H 2024
Earliest FID date	Q1 2023	Q2 2023	Q4 2023	Q4 2023	2H 2024	1H 2025
Earliest COD date[4]	Q3 2025	Q2 2025	Q4 2025	Q2 2025	2H 2027	1H 2028
Total installed capital cost ($ million) [1, 2, 3, 5]	$750 (Class 2)	$156 (Class 3)	$492 (Class 3)	$257 (Class 4)	$875 (Class 4)	$875 (Class 4)

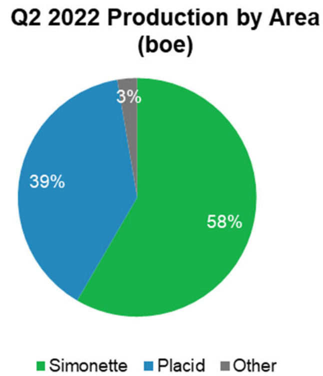
1 – Total installed cost estimates are classified in a manner consistent with American Association of Cost Engineering ("AACE") standards.
2 – Total installed cost numbers exclude carbon capture and sequestration for gas-fired projects. CCUS costs are estimated to be an incremental 60 to 80% of the total 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 estimated on June 8, 2022.
6 – Regulatory and environmental applications are filed with the AEP and AUC.

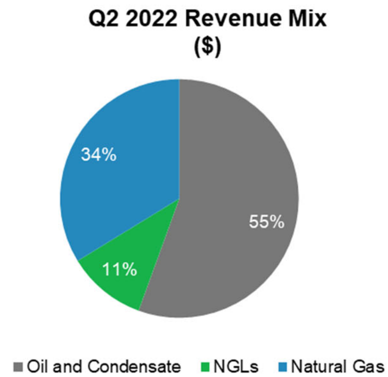
Results of operations

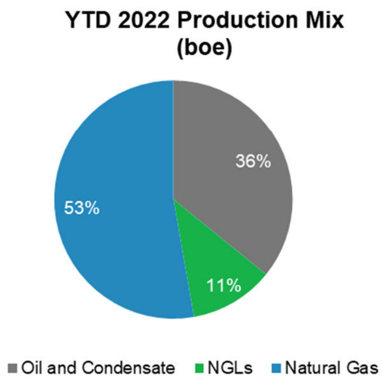
Production

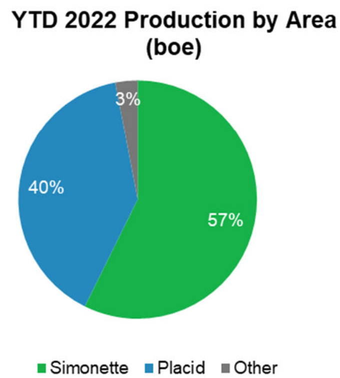
	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Condensate (bbl/d)	**5,673**	3,096	**4,581**	1,595
Light oil (bbl/d)	**718**	331	**797**	337
Heavy oil (bbl/d)	**10**	29	**11**	31
NGLs (bbl/d)	**1,870**	1,220	**1,716**	659
Natural gas (Mcf/d)	**51,232**	36,723	**47,621**	19,045
Total production (boe/d)	**16,810**	10,797	**15,042**	5,797
Oil and condensate % of production	**38%**	32%	**35%**	34%
NGL % of production	**11%**	11%	**11%**	11%
Natural gas % of production	**51%**	57%	**54%**	55%
Total production volumes %	**100%**	100%	**100%**	100%

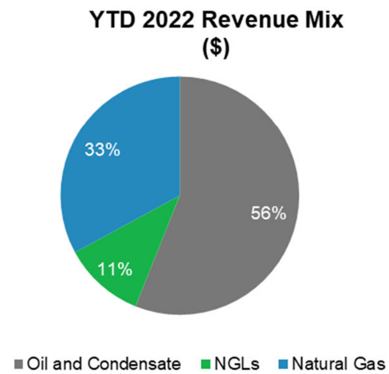












Production during the second quarter of 2022 averaged 16,810 boe/d compared to 10,797 boe/d in the second quarter of 2021. The Company's production volumes have increased significantly year over year reflecting a full period of results from the Simonette assets acquired in April 2021, and the consolidation of Distinction operations in April 2021, as well as production from seven new wells drilled and completed since the first quarter of 2021. The Company's production portfolio during the second quarter of 2022 was 38% oil and condensate, 11% NGLs, and 51% natural gas, with the largest shifts in production seen in natural gas and condensate as compared to 2021 as a result of new wells being more liquids weighted compared to historical production.

Production during the six months ended June 30, 2022 averaged 15,042 boe/d compared to 5,797 boe/d in the comparative period of 2021. During the first six months of 2022, the Simonette and Placid areas contributed 57% and 40% 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 150 bbls/MMcf.

Benchmark and realized prices

	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Liquid benchmark prices				
WTI (US$/bbl)	**108.42**	66.07	**101.35**	61.96
WTI (CDN$/bbl)	**138.46**	81.16	**128.94**	77.19
Edmonton Light (CDN$/bbl)	**136.28**	77.42	**126.75**	72.06
WCS Hardisty (CDN$/bbl)	**122.15**	67.07	**111.52**	62.33
Natural gas benchmark prices				
Henry Hub (US$/MMBtu)	**7.17**	2.83	**6.06**	2.76
Chicago City Gate MI (US$/MMBtu)	**6.97**	2.74	**6.36**	2.68
Chicago City Gate DI (US$/MMBtu)	**7.20**	2.80	**5.81**	6.03
AECO 5A (CDN$/GJ)	**6.86**	2.93	**5.68**	2.96
AECO 7A (CDN$/GJ)	**5.95**	2.70	**5.15**	2.74

	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Alberta Power				
Daily (CDN$/MWh)	**122.47**	104.51	**106.31**	99.99
Daily on Peak (CDN$/MWh)	**136.41**	130.21	**120.80**	124.08
Foreign exchange rates (CAD/USD)	**0.78**	0.81	**0.79**	0.80

Realized prices				
Condensate ($/bbl)	131.33	76.60	125.46	76.63
Light oil ($/bbl)	133.46	75.61	123.83	70.35
Heavy oil ($/bbl)	107.25	57.85	95.30	52.80
NGLs ($/bbl)	86.71	42.04	77.36	40.82
Natural gas ($/Mcf)	9.98	4.06	8.32	4.04
Total ($/boe)	90.17	43.01	80.00	43.37

WTI benchmark prices increased significantly in the three and six months ended June 30, 2022 over the comparative periods of 2021. The increase is primarily as 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 first half of 2022.

Similar to WTI, Edmonton Light benchmark pricing experienced significant increases in 2022 compared to 2021. For the three and six months ended June 30, 2022, Edmonton Light benchmark prices averaged $136.28 and $126.75 per barrel compared to $77.42 and $72.06 per barrel in 2021, respectively.

Natural gas prices also increased significantly in the first half of 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. The Chicago City Gate monthly index benchmark for natural gas for the three and six months ended June 30, 2022 increased to US $6.97/MMBtu and US $6.36/MMBtu, respectively, compared to US $2.74/MMBtu and $2.68/MMBtu during 2021. The Chicago City Gate daily index benchmark for natural gas for the three and six months ended June 30, 2022 saw similar strength in pricing in comparison to 2021 as demand continued to outpace supply in that marketplace.

The Company has a total of 120 MMcf/d of firm Alliance Pipeline transportation service to Chicago contracted through October 31, 2025 that was acquired from both the Simonette and Distinction transactions. The Company has a liquids extraction agreement with Aux Sable until October 31, 2023 whereby liquids contained within the natural gas are extracted, fractionated and sold into the US Midwest refining and petrochemical market, and the remaining natural gas sold into the Chicago area marketplace and interconnecting markets. 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 in the second half of the year.

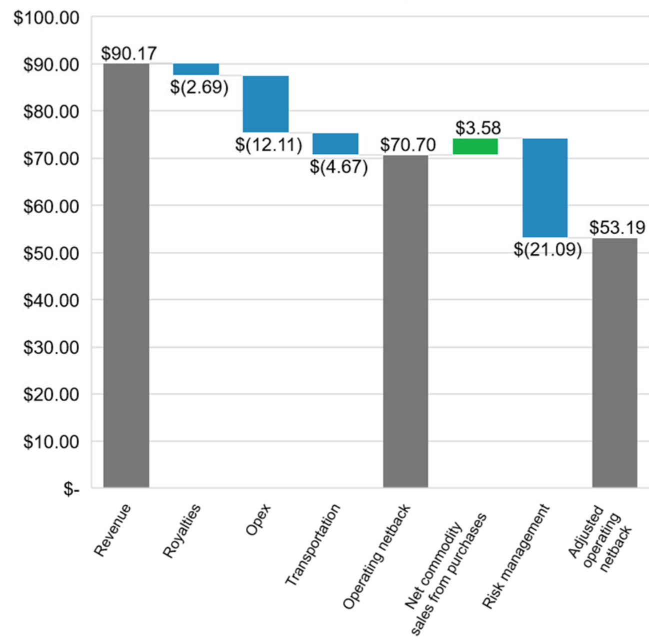
Kiwetinohk also sells natural gas in the AECO market through the Nova Gas Transmission Ltd. ("NGTL") system. Natural gas that is sweetened (through the removal of hydrogen sulfide) at the Company's amine facility is further processed at its 25 percent owned sweet natural gas plant ("Bigstone Sweet Plant")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

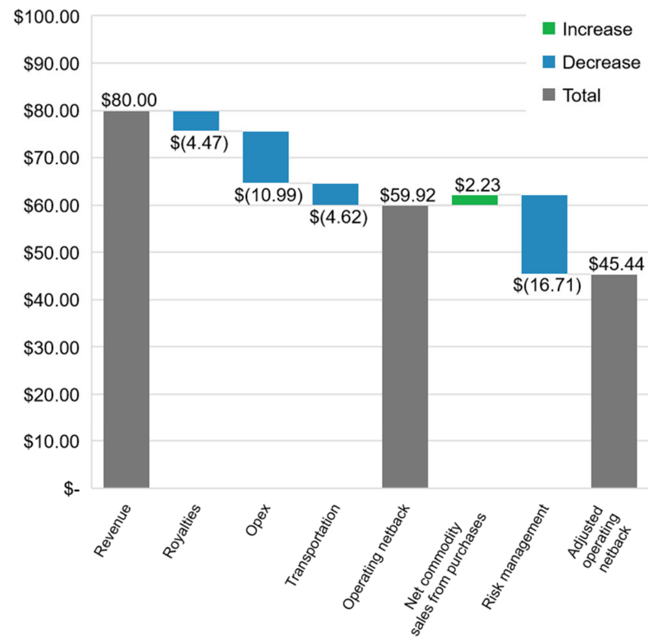
The Company has contracted for approximately 20.5 MMcf/d of transportation service on NGTL with 0.3 MMcf/d expiring in mid-2023, and a further 0.2 MMcf/d expiring at the end of Q1 2024. The remaining 20.0 MMcf/d is contracted until March 31, 2026.

Operating netback

	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Realized price ($/boe)	**90.17**	43.01	**80.00**	43.37
Royalty expenses ($/boe)	**(2.69)**	(2.60)	**(4.47)**	(2.64)
Operating expenses ($/boe)	**(12.11)**	(8.10)	**(10.99)**	(8.14)
Transportation expenses ($/boe)	**(4.67)**	(4.36)	**(4.62)**	(4.13)
Operating netback [1]($/boe)	**70.70**	27.95	**59.92**	28.46
Net commodity sales from purchases [1] ($/boe)	**3.58**	(1.19)	**2.23**	(1.11)
Realized loss on risk management contracts ($/boe)	**(21.09)**	(3.42)	**(16.71)**	(6.09)
Adjusted operating netback [1]	**53.19**	23.34	**45.44**	21.26
Total production (boe/d)	**16,810**	10,797	**15,042**	5,797

1 – Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See "Non-GAAP Measures" section of this MD&A.





Operating netback during the quarter ended June 30, 2022 was $70.70/boe compared to $27.95/boe in the same period in 2021. For the six month period ended June 30, 2022, operating netback was $59.92 compared to $28.46 during 2021. Increases were primarily driven by a significant increase in average realized pricing with increases of $47.16 and $36.63 realized during the three and six month periods respectively. The increase in realized pricing led to higher royalty expenses which were offset in the second quarter by a recovery on finalizing the Company's 2021 gas cost allowance calculation used in the determination of royalty payments; and higher operating expenses as a result of turnaround costs and a decision to use temporary flowback equipment on new wells prior to tie-in to take advantage of the higher commodity price environment.

Adjusted operating netback was $53.19 during the quarter ended June 30, 2022 and $45.44 during the six month period. The Company incurred realized losses on risk management contracts of $21.09 and $16.71 for the three and six-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	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Condensate	**67,807**	21,580	**104,017**	22,123
Light oil	**8,722**	2,275	**17,857**	4,292
Heavy oil	**98**	155	**197**	299
NGLs	**14,753**	4,668	**24,027**	4,870
Natural gas	**46,551**	13,583	**71,699**	13,919
Total commodity sales from production	**137,931**	42,261	**217,797**	45,503

During the three and six month periods ended June 30, 2022, the Company realized a significant increase in revenues 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 $137.9 million, an increase of $95.7 million from the second quarter of 2021. During the six month period, revenue increased to $217.8 million as compared to $45.5 million in 2021.

Risk management contracts

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

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Risk management contracts:				
Unrealized loss	**(7,195)**	(28,060)	**(44,705)**	(26,785)
Realized loss	**(32,262)**	(3,364)	**(45,489)**	(6,387)
Total loss on risk management	**(39,457)**	(31,424)	**(90,194)**	(33,172)
Unrealized loss ($/boe)	**(4.70)**	(28.56)	**(16.42)**	(25.53)
Realized loss ($/boe)	**(21.09)**	(3.42)	**(16.71)**	(6.09)

Risk management contracts have been entered into to mitigate price fluctuations for produced volumes as well as purchased volumes as the Company executes its significant capital program. The following table reconciles the components of the realized loss on risk management contracts:

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Realized gain (loss) on production	**(28,483)**	(3,528)	**(46,028)**	(6,551)
Realized gain (loss) on purchases	**(3,982)**	112	**(385)**	112
Realized gain (loss) on foreign exchange	**203**	52	**924**	52
Total realized loss	**(32,262)**	(3,364)	**(45,489)**	(6,387)
Realized gain (loss) on production ($/boe)	**(18.62)**	(3.59)	**(16.91)**	(6.24)
Realized gain (loss) on purchases ($/boe)	**(2.60)**	0.11	**(0.14)**	0.11
Realized gain (loss) on foreign exchange ($/boe)	**0.13**	0.05	**0.34**	0.05

For the three and six months ended June 30, 2022, the Company recorded realized losses on risk management contracts of $32.3 million and $45.5 million, respectively. The unrealized loss on risk management contracts of $7.2 million and $44.7 million for the three and six months ended June 30, 2022, represents changes in the fair value of risk management contracts during those periods.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting and consequently records the fair value of its natural gas and crude oil financial contracts on the balance sheet at each reporting period with the change in the fair value being classified as unrealized gains and losses in the 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 June 30, 2022:

Type		Q3 2022	Q4 2022	2023	2024
Crude oil					
WTI fixed price	bbl/d	750	750	1,175	500
WTI buy put	bbl/d	2,983	2,650	1,375	-
WTI sell call	bbl/d	1,983	1,733	1,063	-
WTI swap average	US$/bbl	$54.34	$54.35	$65.76	$70.62
WTI buy put average	US$/bbl	$64.84	$64.21	$83.81	-
WTI sell call average	US$/bbl	$59.55	$59.56	$100.63	-
Natural gas [2]					
NYMEX Henry Hub fixed price	MMBtu/d	20,350	15,350	11,375	2,500
NYMEX Henry Hub buy put	MMBtu/d	2,500	9,500	4,375	-
NYMEX Henry Hub sell call	MMBtu/d	2,500	9,500	4,375	-
NGI Chicago basis to NYMEX Henry Hub	MMBtu/d	18,450	21,283	10,625	-
NYMEX Henry Hub fixed price average	US$/MMBtu	$2.97	$2.68	$3.35	$3.23
NYMEX Henry Hub buy put average	US$/MMBtu	$3.00	$4.03	$3.41	-
NYMEX Henry Hub sell call average	US$/MMBtu	$4.75	$4.93	$5.86	-
NGI Chicago basis to NYMEX Henry Hub average	US$/MMBtu	($0.17)	$0.01	$0.05	-
AECO 5A fixed price	GJ/d	2,025	2,025	-	-
AECO 5A average	C$/GJ	$2.09	$2.09	-	-
Natural gas transportation [2,3]					
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	80,000	26,667	-	-
Sell GDD Chicago basis (to NYMEX Henry Hub)	MMBtu/d	(80,000)	(26,667)	-	-
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	($1.25)	($1.25)	-	-
GDD Chicago basis (to NYMEX Henry Hub) average)	US$/MMBtu	($0.12)	($0.12)	-	-

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 June 30, 2022:

Type		Q3 2022	Q4 2022	2023	2024
Foreign exchange					
Sell USD CAD (monthly average)	US$	$5.0 MM	$1.7 MM	-	-
USD CAD buy put	US$	$7.5 MM	$5.8 MM	$0.6 MM	-
USD CAD sell call	US$	$7.5 MM	$5.8 MM	$0.6 MM	-
USD CAD fixed sell rate		$1.29	$1.29	-	-
USD CAD put rate		$1.26	$1.26	$1.26	-
USD CAD call rate		$1.30	$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	June 30, 2022	December 31, 2021
Short term risk management contracts	**62,138**	26,115
Long term risk management contracts	**11,370**	2,688
Total risk management contracts liability	**73,508**	28,803

$ 000's	June 30, 2022	December 31, 2021
Liability on produced volumes	**67,575**	28,529
Liability on purchased volumes	**5,989**	1,936
Asset on foreign exchange contracts	**(56)**	(1,662)
Total risk management liability	**73,508**	28,803

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

Type	Unit	Q4 2022	2023	2024
Natural gas [2]				
NYMEX Henry Hub buy put	MMBtu/d	-	5,000	-
NYMEX Henry Hub buy put average	US$/MMBtu	-	$5.25	-
Natural gas transportation [2,3]				
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	16,667	20,833	-
Sell GDD Chicago basis (to NYMEX Henry Hub)	MMBtu/d	(16,667)	(20,833)	-
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	($1.28)	($1.28)	-
GDD Chicago basis (to NYMEX Henry Hub) average)	US$/MMBtu	0.10	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.

Net commodity sales from purchases

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Commodity sales from purchases	**82,429**	17,770	**143,027**	17,770
Commodity purchases, transportation and other	**(76,943)**	(18,937)	**(136,945)**	(18,937)
Net commodity sales from purchases [1]	**5,486**	(1,167)	**6,082**	(1,167)
Realized hedging loss on purchases[1]	**(3,982)**	112	**(385)**	112
Net commodity sales from purchases after hedging[1]	**1,504**	(1,055)	**5,697**	(1,055)
$/boe – before hedging	**3.58**	(1.19)	**2.23**	(1.11)
$/boe – after hedging	**0.98**	(1.08)	**2.09**	(1.08)

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

In the three and six months ended June 30, 2022, the Company realized net commodity sales from purchases of $5.5 million and $6.1 million on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system.

Royalty expense

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Royalty expense	**4,119**	2,559	**12,158**	2,773
As a % of revenue	**3%**	6%	**6%**	6%
$/boe	**2.69**	2.60	**4.47**	2.64

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties in the three and six months ended June 30, 2022 increased to $4.1 million and $12.2 million as compared to $2.5 million and $2.8 million in the comparative periods of 2021. During the second quarter, royalties as a percentage of revenues decreased to 3% as compared to 6% which resulted from a recovery of $8.2 million being received in relation to finalizing the Company's 2021 GCA calculation. This recovery served to offset increases to royalties resulting from higher benchmark pricing and production during the three and six month periods.

Operating expenses

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Operating expenses	**18,530**	7,954	**29,932**	8,541
$/boe	**12.11**	8.10	**10.99**	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 increased significantly in the three and six months ended June 30, 2022, compared to the comparative periods of 2021 as production volumes increased by 6,013 boe/d and 9,245 boe/d respectively. In addition, during the second quarter of 2022 the Company incurred periodic operating expenses in relation to the Company's first full facility turnarounds, which are required on a four-to-five-year basis, and a decision to accelerate new well production which required producing through higher cost temporary flowback equipment ahead of permanent tie-in operations to take advantage of the high price environment. These incremental operating expenses contributed $5.5 million during 2022.

On a per boe basis, operating costs increased by $4.01/boe in the second quarter of 2022 to $12.11/boe compared to $8.10/boe in the second quarter of 2021. For the six-month period, operating costs increased by $2.85/boe from the prior year period to $10.99/boe. The incremental operating expenses discussed above were $3.56/boe and $2.00/boe respectively for the three and six-month periods, of which, the turnaround accounted for $1.70/boe and $0.95/boe. Excluding these incremental costs, operating expenses during the three and six-month periods ended June 30, 2022 were $8.55/boe and $8.99/boe, respectively. Additional increases over comparable periods in 2021 resulted from 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	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Transportation expenses	**7,144**	4,287	**12,568**	4,334
$/boe	**4.67**	4.36	**4.62**	4.13

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. The increase in transportation expenses for the three and six-month periods is due to higher production levels during 2022 with the $/boe transportation expense being relatively consistent between periods.

Adjusted funds flow from (used in) operations

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Cash flow from (used in) operating activities	**38,780**	(15,753)	**64,112**	(19,332)
Net change in non-cash working capital from operating activities	**36,944**	18,020	**47,958**	18,287
Asset retirement obligation expenditures	**508**	-	**1,164**	-
Restructuring costs	**-**	832	**-**	832
Acquisition costs	**-**	4,806	**-**	5,458
Settlement costs	**-**	10,000	**-**	10,000
Adjusted funds flow from (used in) operations [1]	**76,232**	17,905	**113,234**	15,245
$/boe	49.83	18.22	41.59	14.53

1 – Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. See "Non-GAAP Measures" section of this MD&A.

Adjusted funds from operations increased significantly during 2022 to $76.2 million and $113.2 million for the three and six months ended June 30, 2022, respectively. The significant increase is as a result of strength in 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 $38.8 million and $64.1 million for the three and six months ended June 30, 2022. Cash flow from (used in) operating activities has been adjusted for the net change in non-cash working capital from operating activities, restructuring costs associated with Distinction's *Companies' Creditors Arrangement Act* ("CCAA") process, acquisition costs to complete the Simonette and Distinction acquisitions and $10.0 million in one-time settlement costs to terminate certain carried interest rights and obligations. Non-cash working capital increased during the three and six months ended June 30, 2022 as average accounts receivable balances increased from higher production volumes in a strong commodity price environment.

Free funds flow (deficiency) from operations

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Adjusted funds flow from (used in) operations [1]	**76,232**	17,905	**113,234**	15,245
Capital expenditures (excluding acquisitions and dispositions)	**(52,348)**	(3,870)	**(106,560)**	(4,188)
Free funds flow from operations [1]	**23,884**	14,035	**6,674**	11,057
$/boe	15.61	14.28	2.45	10.54

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 six-month periods ended June 30, 2022 was $23.9 million and $6.7 million relative to $14.0 million and $11.1 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.

General and administrative ("G&A") expenses

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Gross G&A expenses	**5,213**	3,083	**10,619**	5,089
Less capitalized G&A	**(706)**	(300)	**(1,136)**	(300)
G&A Expenses	**4,507**	2,783	**9,483**	4,789
$/boe	**2.95**	2.83	**3.48**	4.56

G&A expenses increased by $1.7 million and $4.7 million during the three and six months ended June 30, 2022 as compared to 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 activity continues to be directly related to business development initiatives in the Green Energy segment consistent with Kiwetinohk's strategy to capture a larger portion of the hydrocarbons value chain by securing access to downstream power, petrochemicals, and LNG/LPG markets.

Gross G&A expenses were reduced by $0.7 million and $1.1 million for direct and incremental G&A costs for upstream and green energy projects that were capitalized during the three and six months ended June 30, 2022 (2021 - $0.3 million and $0.3 million).

Share-based compensation expenses

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Share-based compensation expenses	**2,713**	3,740	**5,998**	7,670
$/boe	**1.77**	3.81	**2.20**	7.31

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

Share-based compensation was $2.7 million and $6.0 million for the three and six months ended June 30, 2022 compared to $3.7 million and $7.7 million in the comparable prior year periods.

Finance costs

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Interest and bank charges	**1,552**	590	**2,478**	590
Accretion of asset retirement obligations	**436**	155	**873**	174
Interest on lease obligations	**5**	-	**16**	-
Deferred financing amortization	**323**	273	**646**	273
Unrealized loss (gain) on foreign exchange	**(869)**	-	**10**	-
Total finance costs	**1,447**	1,018	**4,023**	1,037
$/boe	**0.95**	1.04	**1.48**	0.99

The Company has a $375 million senior secured extendible revolving facility (the “Credit Facility”) with a syndicate of banks. As at June 30, 2022 the Company had drawn $74.8 million on the facility (June 30, 2021 - $60.2 million), net of deferred financing charges. The increase in financing costs for the three and six-month periods ended June 30, 2022 is associated with higher average debt levels outstanding during the periods.

Depreciation and depletion

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Depreciation	**293**	110	**585**	219
Depletion	**16,446**	5,631	**29,067**	5,632
Total depreciation and depletion	**16,739**	5,741	**29,652**	5,851
$/boe	**10.94**	5.84	**10.89**	5.58

Increases in depletion for the three and six-month periods ended June 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 $16.7 million and $29.7 million for the three and six-month periods ended June 30, 2022 (2021 - $5.7 million and $5.9 million respectively).

Exploration and evaluation ("E&E") expenses

$000s	Q2 2022	Q2 2021	YTD 2022	YTD 2021
Depletion	**494**	1,024	**1,216**	3,986
Impairment	**4,342**	-	**6,367**	46,015
Other	**159**	2,161	**667**	3,109
Total E&E expenses	**4,995**	3,185	**8,250**	53,110
$/boe	**3.27**	3.24	**3.03**	50.62

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

E&E depletion expense is recorded on a unit of production basis for properties that have production but have not yet been transferred to property plant and equipment. The decrease in current quarter 2022 depletion is a result of production declines and the transfer of assets to property plant and equipment in June 2022.

Following the Simonette Acquisition the Company has re-prioritized its development and drilling plans to higher return undeveloped land locations and as a result, the Company recognized impairment relating to near-term land expiries of $4.3 million and $6.4 million during the three and six month periods, respectively (2021 - $24.4 million).

Income taxes

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

Category	Deductibility	$000's
Canadian oil and gas property expense ("COGPE")	10%	185,610
Successored COGPE	10%	1,242
Canadian development expense ("CDE")	30%	110,611
Successored CDE	30%	97,149
Canadian exploration expense ("CEE")	100%	-
Successored CEE	100%	15,422
Undepreciated capital cost ("UCC")	Primarily 25%, declining balance	88,608
Non-capital losses	100%	215,616
Share/Debt issue costs	5-year straight line	4,023
Other	Various	(1,797)
Total estimated tax pools		716,484

Asset retirement obligations

The Company's asset retirement obligations ("ARO") of $88.6 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 $31.4 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.

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

	2022		2021				2020	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Production (boe/d)	**16,810**	13,253	12,422	15,058	10,797	741	645	793
Commodity sales from production	**137,931**	79,866	70,267	66,897	42,262	3,242	2,186	2,388
Commodity sales from purchases	**82,429**	60,598	58,398	38,349	17,770	-	-	-
Cash flow from (used in) operating activities	**38,780**	25,332	25,518	31,006	(17,125)	(3,579)	(777)	399
Per share (basic) [1]	**0.88**	0.58	0.58	0.90	(0.58)	(0.19)	(0.05)	0.03
Per share (diluted) [1]	**0.87**	0.58	0.58	0.90	(0.58)	(0.19)	(0.05)	0.03
Net income (loss) [2, 3]	**44,854**	(24,552)	44,306	(34,080)[2]	13,726[3]	(46,267)	9,732	(3,545)
Per share (basic) [1]	**1.02**	(0.56)	1.02	(0.99)	0.47	(2.43)	0.64	(0.27)
Per share (diluted) [1]	**1.01**	(0.56)	1.02	(0.99)	0.47	(2.43)	0.64	(0.27)

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. As at June 30, 2022 the Company has $273.6 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 $42.4 million working capital deficit held at June 30, 2022.

Credit Facility

On June 13, 2021, 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 June 30, 2022, $75.9 million (December 31, 2021- $34.7 million) (before deferred financing costs) was outstanding on the Credit Facility along with $40.5 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 $34.4 million in letters of credit which reduce the available operating facility capacity.

$000	Credit Facility	EDC Facility	Drawn	Letters of credit	Capacity [1]
Credit Facility	375,000	15,000	75,947	40,450	**273,603**

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	June 30, 2022	December 31, 2021
Credit facility drawn	**75,947**	34,698
Deferred financing costs	**(1,184)**	(1,830)
Loans and borrowings	**74,763**	32,868
Adjusted working capital deficit (surplus) [1]	**(18,810)**	18,644
Net debt [1]	**55,953**	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 plus stamping fees, lenders' prime rate or U.S. base rate plus the applicable margins, depending on the form of borrowing by the Company. The applicable margins and stamping fees are based on a sliding scale pricing grid tied to the Company's debt to earnings before interest, taxes, depreciation and amortization ratio ("bank EBITDA"): from a minimum of the bank's prime rate or U.S. base rate plus an applicable margin ranging from 1.75 percent to 5.25 percent or from a minimum of bankers' acceptances rate plus a stamping fee ranging from 2.75 percent to 6.25 percent. The undrawn portion of the Credit Facility is subject to standby fees ranging from 0.6875% to 1.5625% based on the Company's debt to bank EBITDA ratio.

The Credit Facility is secured by a $1.0 billion demand floating charge debenture and a general security agreement over all assets of the Company.

Moving forward the Company plans to use the Credit Facility for working capital purposes to fund go forward capital plans in advance of cash flow from new investments and will target a net debt to annualized 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 June 30, 2022, the Company has $9.0 million of capacity remaining under the LC Facility.

Base shelf prospectus

The Company has filed a short-form base shelf prospectus (Prospectus) 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 June 30, 2022	3-months ended June 30, 2021	6-months ended June 30, 2022	Year ended December 31, 2021
Weighted average shares outstanding				
Basic	**44,061**	29,506	**43,949**	24,285
Diluted	**44,503**	29,506	**44,333**	24,285
Outstanding securities				
Common shares	**44,111**	33,437	**44,111**	33,437
Stock options	**2,649**	2,559	**2,649**	2,559
Performance warrants	**7,725**	7,517	**7,725**	7,517
Capital warrants	**-**	2,007	**-**	2,007
Total diluted outstanding securities	**54,485**	45,520	**54,485**	45,520

At August 10, 2022 the Company has 44,114,266 common shares outstanding.

Commitments, contractual obligations, and provisions

$000s	2022	2023	2024	2025	2026	Thereafter
Gathering, processing and transport [1]	35.1	71.0	73.1	63.8	13.7	49.2
Natural gas purchases	58.6	55.1	-	-	-	-
Lease liabilities	0.1	0.5	1.8	2.1	2.2	9.9
Other	-	0.4	0.4	0.4	0.4	1.1
Risk management contracts	47.1	23.1	3.3	-	-	-
Loans and borrowings	-	-	75.9	-	-	-
Contingent payment consideration	1.5	11.9	-	-	-	-
Accounts payable	56.7	-	-	-	-	-
Total	199.1	162.0	154.5	66.3	16.3	60.2

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. The Company has a liquids extraction agreement with Aux Sable through October 2023. Through Distinction, the Company acquired a separate independent transportation agreement with Alliance to deliver 29.7 MMcf/d of natural gas volumes until October 31, 2025 to Chicago that is not contracted to Aux Sable.

The Company currently has secured 80,000 GJ per day of gas supply (approximately 70.1 MMcf per day) from several natural gas producers through 2022 and approximately 10,000 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. Subsequent to June 30, 2022 the Company entered into an additional natural gas purchase commitment for approximately $3.8 million (2022 - $1.5 million; 2023 - $2.3 million).

Acquisitions

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

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

1 – Includes value of Distinction net identifiable assets as at April 28, 2021 immediately prior to the Simonette Acquisition.
2 – Distinction working capital includes $95.8 million of cash acquired.
3 – The investment is comprised of $62.9 million in cash (average cost of $12.91 per share), transaction costs of approximately $2.8 million and an equity gain on investment of $32.6 million and subsequent to the joint Simonette Acquisition Distinction had $63.3 million of debt and working capital of $0.5 million.
4 – Additional shares were issued pursuant to the Arrangement (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 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 six months ended June 30, 2022, the Company incurred a total of $0.1 million and $0.7 million, respectively (June 30, 2021 – $0.2 million and $0.6 million), in the following related party transactions:

- The Company has retained a law firm to provide legal services on corporate matters. A director of the Company is a partner of this law firm.
- The Company has engaged an energy information services company to assist in the evaluation of prospective upstream oil and gas properties. A director of the Company is the CEO of this firm.

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

Health, safety and environmental

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

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

Risk factors and risk management

The Company's management team is focused on long-term strategic planning and has identified key material risks, uncertainties and opportunities associated with the Company's business that can impact the financial position, operations, cash flows and future prospects of the business. 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 legislationis 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 April 1, 2022, and ending on June 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 six months ended June 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 short-term exposure with these counterparties.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The Company operates in a capital-intensive industry with medium to long-term cash cycles. The Company may face lengthy development lead times, as well as risks associated with rising capital costs and timing of project completion because of the availability of resources, permits and other factors beyond its control. The Company regularly monitors its cash requirements by assessing its ability to generate cash flow from operations, access to external financing, debt obligations as they become due, and its expected future operating and capital expenditure requirements.

The Company's financial instruments recognized on the 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.

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 June 30, 2022.

Other

Non-GAAP measures
Certain information set forth in this document contains non-GAAP measures, including “operating netback”, “adjusted operating netback“, “adjusted funds flow from (used in) operations”, “free funds flow (deficiency)” from operations, “adjusted working capital deficit (surplus)”, “credit facility capacity”, “net debt”, “net debt to annualized adjusted funds flow from operations”, and “net commodity sales from purchases”. 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	June 30, 2022	December 31, 2021
Current assets	**95,336**	47,557
Current liabilities	**(137,738)**	(92,316)
Working capital deficit	**(42,402)**	(44,759)
Short term risk management contracts	**62,138**	26,115
Adjusted working capital surplus (deficit)	**19,736**	(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 deficit (surplus) 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	June 30, 2022	December 31, 2021
Loans and borrowings	**74,763**	32,868
Adjusted working capital (surplus) deficit	**(19,736)**	18,644
Net debt	**55,027**	51,512
Net debt to annualized adjusted funds flow from operations	**0.33**	0.74

Net commodity sales from purchases

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.

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;
- receipt of certain regulatory approvals, including AUC power plant approvals and AEP industrial approval and the timing of such approvals;
- anticipated grid capacity for green energy projects;
- development and permitting of the Company's solar and gas-fired power portfolio;
- anticipated production increases into the first quarter of 2023;
- future investigations by the Company of CCUS and application for grants related thereto;
- industry volatility and uncertainty around the timing and extent of a COVID-19 recovery;
- future taxes payable by the Company;
- 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;
- anticipated well production;
- asset retirement obligations;
- 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 anticipated development and permitting of the Company's solar and gas-fired power portfolio
- 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 aboveReaders 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
AEP	Alberta Environment and Parks
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

Farid Shirkavand
Vice President

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

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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

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