Management's discussion and analysis

The following is Management's Discussion and Analysis ("MD&A") of the financial performance and results of operations for Kiwetinohk Energy Corp. ("Kiwetinohk" or the "Company") as at and for the three and nine months ended September 30, 2023. Kiwetinohk's common shares commenced trading on the Toronto Stock Exchange under the symbol KEC on January 14, 2022.

This MD&A should be read in conjunction with the Company's condensed consolidated interim financial statements as at and for the three and nine months ended September 30, 2023 (the "Financial Statements") and the audited financial statements as at and for the year ended December 31, 2022. Additional information is available on Kiwetinohk's website at www.kiwetinohk.com and SEDAR+ at www.sedarplus.ca. 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 and Other Financial Measurements", "Forward-Looking Statements", "Future Oriented Financial Information", "Abbreviations" and "Oil and Gas Advisories" below.

The reporting currency is the Canadian dollar, and all dollar amounts in this MD&A are stated in Canadian dollars unless otherwise indicated. This MD&A is dated November 7, 2023.

Overview of business

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

Upstream

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

Power

The power business unit is pursuing greenfield and examining potential brownfield development opportunities across a diversified Alberta-based power generation project portfolio that currently includes renewable solar, and natural gas-fired power with carbon capture and storage ("CCS"). Successful development of Kiwetinohk's power projects will enable the production of clean, reliable, dispatchable, affordable energy and provide downstream markets for potential future integration of the Company's natural gas production, allowing it to capture a larger portion of the energy value chain.

Financial and operating highlights

	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Production				
Oil & condensate (bbl/d)	**6,367**	5,558	**6,770**	5,446
NGLs (bbl/d)	**2,765**	1,944	**2,520**	1,793
Natural gas (Mcf/d)	**72,518**	53,912	**75,492**	49,741
Total (boe/d)	**21,218**	16,487	**21,872**	15,529
Oil and condensate % of production	**30%**	34%	**31%**	35%
NGL % of production	**13%**	12%	**11%**	12%
Natural gas % of production	**57%**	54%	**58%**	53%
Realized prices				
Oil & condensate ($/bbl)	**100.05**	114.48	**97.43**	121.48
NGLs ($/bbl)	**48.21**	75.50	**53.84**	76.68
Natural gas ($/Mcf)	**3.53**	10.20	**3.92**	9.01
Total ($/boe)	**48.38**	80.86	**49.87**	80.31
Royalty expense ($/boe)	**(2.75)**	(12.51)	**(4.68)**	(7.34)
Operating expenses ($/boe)	**(9.17)**	(11.13)	**(8.51)**	(11.04)
Transportation expenses ($/boe)	**(5.59)**	(6.63)	**(5.65)**	(5.34)
Operating netback [1] ($/boe)	**30.87**	50.59	**31.03**	56.59
Realized gain (loss) on risk management ($/boe) [2]	**1.23**	(19.41)	**1.97**	(16.96)
Realized gain (loss) on risk management - purchases ($/boe) [2]	**1.59**	(16.92)	**1.88**	(6.77)
Net commodity sales from purchases (loss) ($/boe) [1]	**(1.22)**	21.64	**(0.92)**	9.18
Adjusted operating netback [1]	**32.47**	35.90	**33.96**	42.04
Financial results ($000s, except per share amounts)				
Commodity sales from production	**94,432**	122,644	**297,788**	340,441
Net commodity sales from purchases (loss) [1]	**(2,376)**	32,813	**(5,490)**	38,895
Cash flow from operating activities	**60,294**	91,710	**181,814**	155,822
Adjusted funds flow from operations [1]	**55,314**	49,342	**177,614**	162,576
Per share basic	**1.26**	1.12	**4.03**	3.69
Per share diluted	**1.25**	1.10	**3.99**	3.65
Net debt to annualized adjusted funds flow from operations [1]	**0.67**	0.65	**0.67**	0.65
Free funds flow deficiency from operations (excluding acquisitions/ dispositions) [1]	**(7,827)**	(11,119)	**(52,961)**	(4,445)
Net (loss) income	**(12,056)**	55,379	**63,594**	75,681
Per share basic	**(0.27)**	1.26	**1.44**	1.72
Per share diluted	**(0.27)**	1.24	**1.43**	1.70
Capital expenditures prior to (dispositions) acquisitions [1]	**63,141**	60,461	**230,575**	167,021
Net (dispositions) acquisitions [1]	**(1,645)**	59,181	**(1,995)**	57,323
Capital expenditures and net (dispositions) acquisitions [1]	**61,496**	119,642	**228,580**	224,344
Balance sheet ($000s, except share amounts)				
Total assets	**1,028,176**	837,349	**1,028,176**	837,349
Long-term liabilities	**279,402**	214,536	**279,402**	214,536
Net debt [1]	**187,517**	125,263	**187,517**	125,263
Adjusted working capital (deficit) surplus [1]	**(8,240)**	(24,065)	**(8,240)**	(24,065)
Weighted average shares outstanding				
Basic	**43,884,942**	44,114,105	**44,058,853**	44,004,315
Diluted	**44,389,687**	44,795,079	**44,554,647**	44,491,336
Shares outstanding end of period	**43,785,925**	44,117,187	**43,785,925**	44,117,187

1 – Non-GAAP and other financial 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 and Other Financial Measures" section of this MD&A
2 – Realized gain (loss) on risk management contracts includes settlement of financial hedges on production and foreign exchange, with gains (loss) on contracts associated with purchases presented separately.

Guidance update

Management continues to execute on its upstream and power development plans and is maintaining 2023 corporate and upstream guidance targets. Power project development is currently being managed to focus development expenditures primarily on the Homestead and Opal projects, which are the most advanced and currently considered the highest priority. The Company is also actively deferring expenditures on the remaining power projects within its development project portfolio, where possible, as it awaits further clarity from provincial and federal governments on pending electricity regulations. However, Kiwetinohk expects to continue to incur costs required to maintain the competitive position of all its projects within the AESO queue. As a result of these measures, 2023 power expenditures are now expected to be between $15 - $18 million which is below the previously announced guidance of $18 - $22 million.

On November 1, 2023 the Company disposed of non-core assets in the Rimbey area for estimated proceeds of $17.6 million subsequent to closing adjustments. The Rimbey assets were not considered core to Kiwetinohk's upstream strategy and were under-capitalized within the portfolio as the Company is focused on the long-term development of its liquids-rich Simonette and Placid assets. They represented less than 1% of total proved plus probable reserves as at December 31, 2022 and contributed approximately 1% of corporate production in the nine months ended September 30, 2023. This sale allows Kiwetinohk to accelerate debt reduction, further strengthening its balance sheet, with the ratio of net debt to adjusted funds flow from operations now expected to exit 2023 at the low end of previously published guidance of 0.7x - 0.9x.

The following table summarizes Kiwetinohk's guidance for 2023:

2023 Financial & Operational Guidance		Revised November 7, 2023	Revised August 1, 2023
Production (2023 average) [1]	Mboe/d	21.5 - 23.5	21.5 - 23.5
Oil & liquids	Mbbl/d	9.5 - 10.4	9.5 - 10.4
Natural gas [2]	MMcf/d	71.9 - 78.5	71.9 - 78.5
Financial			
Royalty rate	%	10% - 12%	10% - 12%
Operating costs	$/boe	$8.25 - $9.25	$8.25 - $9.25
Transportation	$/boe	$6.00 - $6.50	$6.00 - $6.50
Corporate G&A expense [3]	$MM	$22 - $24	$22 - $24
Cash taxes [4]	$MM	$0	$0
Capital guidance	$MM	$300 - $318	$303 - $322
Upstream	$MM	$285 - $300	$285 - $300
DCET	$MM	$230 - $240	$230 - $240
Plant expansion, production maintenance and other	$MM	$55 - $60	$55 - $60
Power	$MM	$15 - $18	$18 - $22
2023 Adjusted Funds Flow from Operations commodity pricing sensitivities [5]			
US$70/bbl WTI & US$2.75/MMBtu HH	CAD$MM	$230 - $250	$230 - $250
US$80/bbl WTI & US$3.25/MMBtu HH	CAD$MM	$240 - $265	$240 - $265
US$ WTI +/- $1.00/bbl	CAD$MM	+/- $0.8	+/- $3.9
US$ Chicago +/- $0.10/MMBtu	CAD$MM	+/- $0.3	+/- $6.1
CAD$ AECO 5A +/- $0.10/GJ	CAD$MM	+/- $0.3	+/- $2.1
Exchange Rate (CAD$/US$) +/- $0.01	CAD$MM	+/- $0.4	+/- $2.4
2023 Net debt to Adjusted Funds Flow from Operations sensitivities [5]			
US$70/bbl WTI & US$2.75/MMBtu HH	X	0.8x - 0.9x	0.8x - 0.9x
US$80/bbl WTI & US$3.25/MMBtu HH	X	0.7x - 0.8x	0.7x - 0.8x

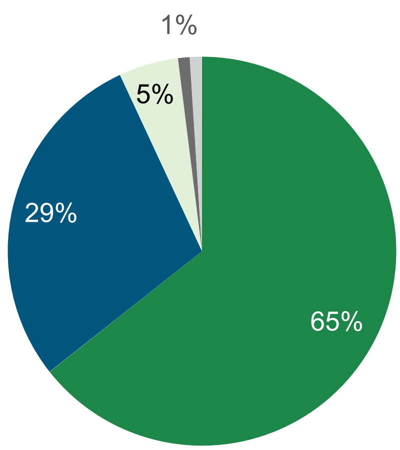
1 – Production and cash operating costs include scheduled downtime to accommodate plant expansion work completed in the third quarter.
2 – Chicago sales of ~90% expected for 2023.
3 – Includes G&A expenses for all divisions of the Company – corporate, upstream, power and business development.
4 – The Company expects to pay cash taxes of approximately $0.3 million on its US subsidiary during 2023. No Canadian taxes are anticipated in 2023.
5 – Non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Please refer to the section “Non-GAAP Measures” herein.
6 – Assumes US$75/bbl WTI, US$3.00/mmbtu HH, US$1.00/mmbtu HH - AECO basis diff, $0.75 USD/CAD.

Capital expenditures

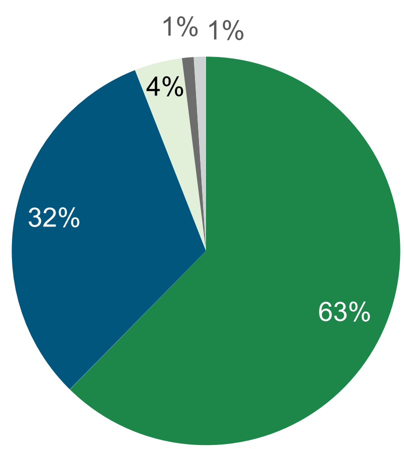
$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Drilling, completions, and equipping	**40,761**	50,371	**144,286**	142,445
Facilities, pipelines, roads and optimization	**18,360**	7,722	**73,953**	16,779
Power projects	**2,865**	1,442	**8,163**	5,210
Land and other	**398**	274	**1,355**	799
Capitalized G&A	**757**	652	**2,818**	1,788
Capital expenditures [1]	**63,141**	60,461	**230,575**	167,021
Upstream net (dispositions) acquisitions [1]	**(1,645)**	59,181	**(1,995)**	54,823
Power net acquisitions [1]	**—**	—	**—**	2,500
Capital and net (dispositions) acquisitions [1]	**61,496**	119,642	**228,580**	224,344

1 – Non-GAAP and other financial 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 and Other Financial Measures” section of this MD&A.

Capital expenditures Q3 2023[1]



Capital expenditures YTD 2023[1]



1 – Capital expenditures shown are before Acquisitions/dispositions.

Drilling, completions and equipping | Facilities, pipelines, roads and optimization | Power projects | Land and other | Capitalized G&A

Drilling, completions and equipping

For the three and nine months ended September 30, 2023, the Company spent $40.8 million and $144.3 million, respectively, across all operating areas. During the first nine months, the Company's development program within Placid included four new Montney wells which were tied in during the second quarter of 2023. In Simonette, the Company has completed and tied in five wells with the most recent two well Duvernay pad on-stream at the end of the third quarter. In addition, the Company returned to a four well Duvernay pad that was previously halted to accommodate the caribou calving season, and completed drilling operations with production expected to be on-stream during the fourth quarter of 2023.

The Company remains focused on developing both the Duvernay and Montney assets with the program aiming to delineate and add value to its upstream assets while retaining core land in both Simonette and Placid.

Facilities, pipelines, roads and optimization

For the three and nine months ended September 30, 2023, the Company spent $18.4 million and $74.0 million, respectively, on facilities, pipelines, roads and production optimization. Construction of an expansion of the Company's 10-29 processing plant in the Simonette area (to increase inlet capacity by approximately ~30 MMcf/d through addition of two new compressors) was largely completed in the third quarter of 2023. In addition, the Company has incurred engineering and procurement costs in connection with an expansion of its 5-31 plant (to add ~15 MMcf/d of inlet capacity) during the first nine months of 2023. Construction of this expansion has been delayed until it is required to accommodate anticipated production growth. In addition,costs were incurred to construct roads, leases and pipelines required to execute the Company's drilling program and allow for future production growth.

Power development projects

During the first nine months of 2023, the Company continued to advance its power development portfolio, which includes four gas-fired and three solar projects, with a total estimated nameplate capacity of approximately 2,150 MW.

For the three and nine months ended September 30, 2023, excluding capitalized G&A, the Company invested $2.9 million and $8.2 million, respectively, to advance all seven power projects. Expenditures included costs to complete engineering, consultations, regulatory reviews, environmental studies, Alberta Electric Systems Operator ("AESO") processes, legal reviews and various pre-Front End Engineering and Design ("FEED") and FEED work, as well as, other risk reduction and contracting activities. The majority of the Company's power capital expenditures in 2023 has been directed to the Homestead Solar and Opal Firm Renewable projects, both of which are well advanced in their respective regulatory approval processes. Alberta Utilities Commission ("AUC") transmission approvals remain as the final key regulatory hurdle for each project.

The transmission line regulatory approvals for the Homestead project, which advanced to Stage 4 of the AESO regulatory process, are now expected to require an AUC hearing which will result in the delay of a Final Investment Decision ("FID") to the second half of 2024. The Company has selected a large, reputable engineering, procurement and construction ("EPC") firm with experience in utility-scale solar construction for the project. The Company has continued to optimize the design and development plan for Homestead resulting in estimated savings of $25.0 million when compared to previous capital cost estimates. Capital costs for this project are now estimated at $725.0 million. The Company exercised land lease options on its Homestead project to secure its position for future development and retains the ability to terminate these leases upon providing notice to landowners and satisfaction of certain reclamation requirements.

Work also continues to advance detailed engineering on the 101MW Opal project, currently in Stage 3 of the AESO regulatory review process. The Company has delayed the earliest expected FID for Opal to the second half of 2024 as it awaits transmission line approval and is currently reviewing the implications of the Federal Government's draft Clean Electricity Regulation ("CER").

Effective as of April 2023, the AESO implemented a new connection assessment process under which newly proposed power generation projects will be batched ("clustered") with their impact studied together simultaneously as opposed to on an individual basis. The cluster assessment process will apply to generation and storage projects providing 5 MW or more of generation capacity to the Alberta interconnected electric system. During the third quarter, Kiwetinohk received confirmation that none of the projects in its power portfolio are affected by the new AESO cluster study assessment process thereby enhancing regulatory clarity for the Company's projects. Multiple power projects have been cancelled from the AESO's Connection Project List following the introduction of the cluster study assessment process. Kiwetinohk continues to advance its significant development portfolio and remains competitively well positioned within the Alberta market.

On August 3, 2023, the Generation Approvals Pause Regulation came into effect through a concurrent order-in-council by the Alberta Government. This regulation imposes a moratorium on the AUC for granting approvals for renewable electricity-generating power projects with a further update expected to be provided to the government by the AUC after February 29, 2024. Subsequently, on August 22, 2023, the AUC issued a statement clarifying its position and confirming that it will continue processing both existing and new applications during the pause period. The Company's Homestead solar project has already received AUC power plant approval and is unaffected by the moratorium while the Company's Phoenix and Granum solar projects will continue to be reviewed by the AUC during the pause period.

Early-stage development and design factors and the status of each project as at November 7, 2023 are summarized in the following table:

Early-stage power development, design factors & status	Homestead (Solar 1)	Opal (Firm Renewable 1) [9]	Granum (Solar 2)	Phoenix (Solar 3)	Black Bear (NGCC 2)	Flipi (NGCC 1)	Little Flipi (Firm Renewable 2) [9]
Approximate Capacity (nameplate, AC) [6]	400 MW	101 MW	350 MW	170 MW	500 MW	500 MW	124 MW
Approximate Capacity (net to grid, AC)	400 MW	97 MW	350 MW	170 MW	466 MW	466 MW	120 MW
Capacity factor	27% [6]	20% [7]	27% [6]	27% [6]	90%	90%	20% [7]
Heat rate [8] (MJ/KWH: +/-5%)	—	7.6	—	—	6.0	6.0	TBD
AESO stage	4	3	2	3	2	3	2
Earliest FID date	H2 2024	H2 2024	TBD [11]	TBD [11]	TBD [11]	TBD [11]	TBD [11]
Earliest COD date [4, 11]	H2 2026	H1 2026	TBD [11]	TBD [11]	TBD [11]	TBD [11]	TBD [11]
Total estimated installed capital cost ($ million) [1, 2, 3, 5]	$725 (Class 2)	$156 (Class 3)	$660 (Class 3)	$320 (Class 4)	$875 (Class 4)	$875 (Class 4)	Preliminary estimate underway [10]

1 – Total installed cost estimates are classified in a manner consistent with American Association of Cost Engineering ("AACE") standards and excludes costs to finance projects.
2 – Total installed cost numbers exclude CCS for gas-fired projects. Preliminary carbon capture capital cost for an NGCC power plant is estimated to be an incremental 60 to 80% of the total installed power plant cost based on a third party engineering study (March 2022), and for Opal, an incremental 70 to 100% of the total installed power plant cost based on an independent engineering study (January 2023).
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 a positive FID is reached, the Company will advance the project towards estimated Commercial Operations Date ("COD").
5 – Capital costs may increase due to, among other things, 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 were updated with completion of a Class 2 estimate on June 8, 2022 and further refined through the EPC contract. Pre-Feed studies by a third party engineering firm on NGCC plants (January 2023) validate previous estimates.
6 – First year capacity factor based on DC/AC ratio of 1.35, and bifacial, single axis solar panel tracking design.
7 – Designed for intermittent operation. The actual dispatch will be based on market conditions and contracting.
8 – Gas-fired generation simple cycle heat rates averaged 9.5 and NGCC heat rates averaged 7 on existing projects within the AESO grid as per publicly available data.
9 - The term "Firm Renewable" is a Kiwetinohk-originated term that describes efficient, flexible-output, fast-responding, gas-fired, internal reciprocating engine-driven power generation.
10 - Kiwetinohk has advanced development of the project including progressing AESO stage reviews, securing a project site, initiating a preliminary capital cost estimate, and building a project schedule.
11 - Kiwetinohk continues to monitor and assess the draft Clean Electricity Regulations and the Alberta Utilities Commission Inquiry and any impact on project timelines. Indicated timelines are the best estimate taking into account potential delays.

Kiwetinohk is not in a position to update FID and COD dates on further dated projects until clarity is provided on pending electricity regulations from provincial and federal governments and regulators.

Carbon storage hubs

The Company has continued to evaluate its two carbon storage hubs during the first nine months of 2023, completing a feasibility study and identifying locations for appraisal wells. Kiwetinohk believes it will be well positioned as a primary user of its awarded carbon hubs through its associated power projects, Opal and Black

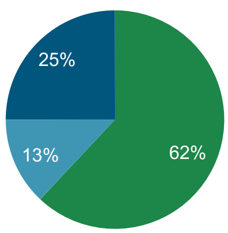
Bear, in development and through potential future CCS projects it may develop for its own use and the use of third parties.

Results of operations

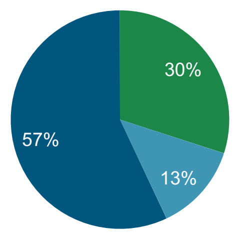
Production

	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Oil & condensate (bbl/d)	**6,367**	5,558	**6,770**	5,446
NGLs (bbl/d)	**2,765**	1,944	**2,520**	1,793
Natural gas (Mcf/d)	**72,518**	53,912	**75,492**	49,741
Total production (boe/d)	**21,218**	16,487	**21,872**	15,529
Oil and condensate % of production	**30%**	34%	**31%**	35%
NGL % of production	**13%**	12%	**11%**	12%
Natural gas % of production	**57%**	54%	**58%**	53%
Total production volumes %	**100%**	100%	**100%**	100%

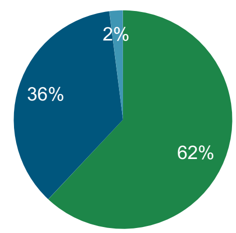
Revenue Mix ($)
Q3 2023



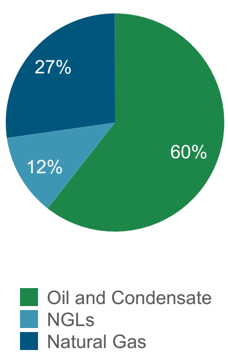
Production Mix (boe)
Q3 2023



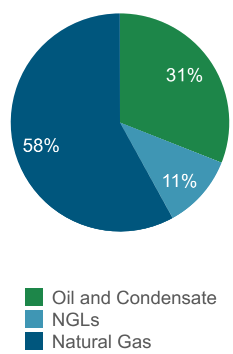
Production by Area (boe)
Q3 2023



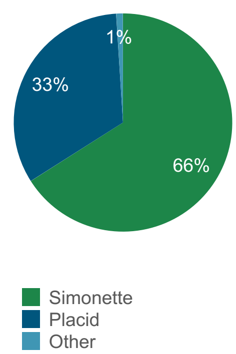
YTD 2023



YTD 2023



YTD 2023



Production during the third quarter of 2023 averaged 21,218 boe/d compared to 16,487 boe/d in the third quarter of 2022. Production during the nine months ended September 30, 2023 averaged 21,872 boe/d and increased by 41% compared to 15,529 boe/d in 2022. Kiwetinohk's production volumes have increased significantly through the Company's capital development program, adding incremental production through new wells brought on stream in key development areas of Simonette and Placid which together contributed 99% of year-to-date production volumes. In addition, on September 15, 2022 the Company completed an acquisition of an additional working interest in the Placid area which contributed to production growth in 2023 relative to the comparative periods in 2022. This year over year growth was achieved despite the fact that the Company's nine month production volumes were negatively impacted by the Alberta wildfires during the month of May, which forced a shut-in and loss of production of approximately 1,000 boe/d on an annualized basis.

The Company's production portfolio during the nine months ended September 30, 2023 was 31% oil and condensate, 11% NGLs, and 58% natural gas, with the natural gas weighting increasing from 2022 as a result of the composition of new wells brought on stream being more gas weighted compared to historical production.

Benchmark and realized prices

	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Liquid benchmark prices				
WTI (US$/bbl)	**82.26**	91.55	**77.39**	98.09
WTI (CDN$/bbl)	**110.38**	119.46	**104.13**	125.80
Edmonton Light (CDN$/bbl)	**107.89**	116.60	**100.62**	123.41
Natural gas benchmark prices				
Henry Hub (US$/MMBtu)	**2.55**	8.20	**2.69**	6.77
Chicago City Gate MI (US$/MMBtu)	**2.29**	7.86	**2.87**	6.86
Chicago City Gate DI (US$/MMBtu)	**2.31**	7.38	**2.31**	6.33
AECO 5A (CDN$/GJ)	**2.46**	3.95	**2.61**	5.10
AECO 7A (CDN$/GJ)	**2.26**	5.50	**2.87**	5.27
Foreign exchange rates (CAD/USD)	**0.75**	0.77	**0.74**	0.78

	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Realized prices (before impact of hedging program)				
Oil & condensate ($/bbl)	**100.05**	114.48	**97.43**	121.48
NGLs ($/bbl)	**48.21**	75.50	**53.84**	76.68
Natural gas ($/Mcf)	**3.53**	10.20	**3.92**	9.01
Total ($/boe)	**48.38**	80.86	**49.87**	80.31

WTI benchmark prices decreased in both the three and nine months ended September 30, 2023, over the comparative periods of 2022, averaging $110.38 and $104.13 per barrel compared to $119.46 and $125.80 per barrel, respectively. The reported year over year decreases in benchmark prices are in large part a reflection of the very high prices that prevailed through much of 2022 which was the result of simultaneous supply constraints, exacerbated by Russia's invasion of Ukraine and a resurgence of energy demand following the easing of COVID related lockdowns last year. Crude oil prices in 2023 are lower, but have remained relatively strong as a result of expectations of a tighter supply given production cuts in Saudi Arabia and ongoing sanctions against Russia which have offset concerns with respect to impact of weaker economic growth on global demand and growing US crude oil inventories.

Edmonton Light benchmark pricing also experienced decreases in 2023 compared to 2022, generally driven by the same factors as WTI prices. For the three and nine months ended September 30, 2023, Edmonton Light benchmark prices averaged $107.89 and $100.62 per barrel compared to $116.60 and $123.41 per barrel in the comparative periods of 2022, respectively.

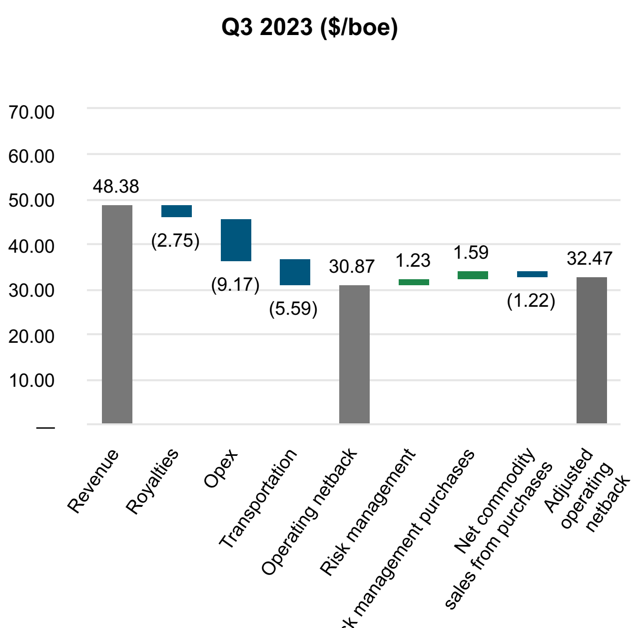
Henry Hub natural gas prices decreased in the three and nine months ended September 30, 2023, when compared to the prior year period due to record high inventory levels throughout the northern hemisphere. Henry Hub prices in 2022 were unusually high in 2022, driven by flat US production growth, a resurgence of domestic demand at the time of increased LNG exports and low storage levels. The Chicago City Gate monthly index benchmark for natural gas also declined in the three and nine months ended September 30, 2023, compared to prior periods for similar reasons. The Chicago City Gate monthly benchmark averaged US $2.29 and US $2.87 per MMBtu compared to US $7.86 and US $6.86 per MMBtu in the comparative periods of 2022, respectively.

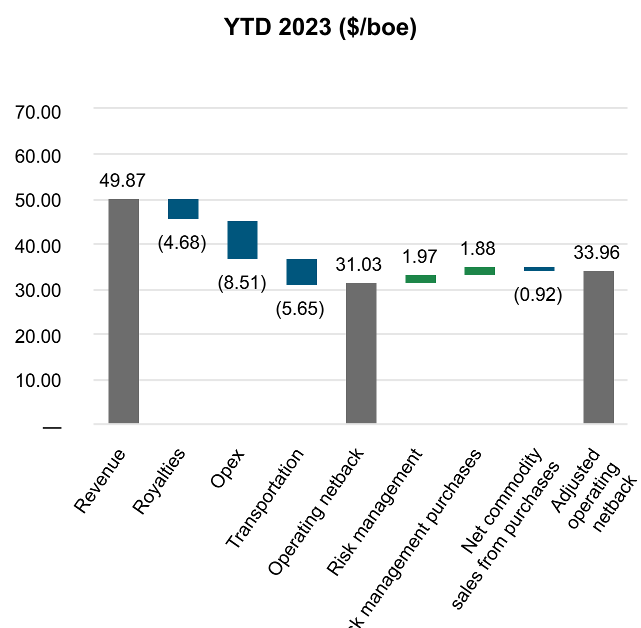
Natural gas prices at AECO in Alberta also decreased as new supply outpaced demand in the basin. On average, AECO 7A spot prices decreased during the three and nine months ended September 30, 2023, when compared to the same periods in 2022, decreasing by $3.24/GJ to $2.26/GJ for the third quarter of 2023, and by $2.40/GJ to $2.87/GJ for the nine months.

Operating netback

	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Realized price ($/boe)	**48.38**	80.86	**49.87**	80.31
Royalty expenses ($/boe)	**(2.75)**	(12.51)	**(4.68)**	(7.34)
Operating expenses ($/boe)	**(9.17)**	(11.13)	**(8.51)**	(11.04)
Transportation expenses ($/boe)	**(5.59)**	(6.63)	**(5.65)**	(5.34)
Operating netback [1]($/boe)	**30.87**	50.59	**31.03**	56.59
Realized gain (loss) on risk management ($/boe) [2]	**1.23**	(19.41)	**1.97**	(16.96)
Realized gain (loss) on risk management contracts - purchases ($/boe) [2]	**1.59**	(16.92)	**1.88**	(6.77)
Net commodity sales from purchases (loss)($/boe) [1]	**(1.22)**	21.64	**(0.92)**	9.18
Adjusted operating netback [1]	**32.47**	35.90	**33.96**	42.04
Total production (boe/d)	**21,218**	16,487	**21,872**	15,529

1 – Non-GAAP and other financial 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 and Other Financial Measures" section of this MD&A.
2 – Realized gain (loss) on risk management contracts includes settlement of financial hedges on production and foreign exchange, with gains on contracts associated with purchases presented separately.





Operating netback for the three and nine months ended September 30, 2023, was $30.87/boe and $31.03/boe, respectively, compared to $50.59/boe and $56.59/boe in the comparable periods of 2022. The decrease in both periods was attributable to lower average realized prices, an increase in the gas weighting within production mix, partially offset by lower royalty expenses resulting from a gas cost allowance recovery and lower per barrel operating cost savings as higher production was accommodated by the Company's existing processing facilities. Reductions in the use of higher cost interruptible NGL transportation led to reduced third quarter transportation charges when compared to the third quarter of 2022. Per barrel transportation increased during the nine months ended September 30, 2023, as a result of additional volumes flowing on the higher cost Alliance pipeline in order to access markets where a better all-in netback could be achieved.

Adjusted operating netback incorporates the impact of risk management contracts and marketing activities. Adjusted operating netback for the three and nine months ended September 30, 2023, decreased compared to 2022, with $32.47/boe realized during the third quarter and $33.96/boe during the first nine months, for the reasons discussed above. Gains realized on commodity risk management contracts during 2023 partially mitigated the impact of pricing declines during the three and nine month periods as a portion of volumes are systematically hedged, in accordance with established risk management guidelines as approved by the Company's board of directors, to manage price volatility and ensure predictable cash flows during a period of significant capital expenditures and growth. The Company also manages cash flows associated with commodity sales from purchases through an ongoing hedging program, as further described below (see Net commodity sales from purchases).

Revenue

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Oil & condensate	**58,608**	58,532	**180,064**	180,603
NGLs	**12,261**	13,501	**37,033**	37,528
Natural gas	**23,563**	50,611	**80,691**	122,310
Total commodity sales from production	**94,432**	122,644	**297,788**	340,441

Revenue decreased to $94.4 million and $297.8 million, respectively, for the three and nine months ended September 30, 2023, representing 23% and 13% respective declines over the comparative periods in 2022. Decreases for the three and nine months ended September 30, 2023 were due to a weaker commodity price environment with the Company realizing pricing of $48.38/boe and $49.87/boe, respectively, as compared to $80.86/boe and $80.31/boe in the comparative periods of 2022. Declines in realized pricing were partially offset by greater production levels during the 2023 periods.

Net commodity sales from purchases

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Commodity sales from purchases	**19,464**	77,623	**57,437**	220,650
Commodity purchases, transportation and other	**(21,840)**	(44,810)	**(62,927)**	(181,755)
Net commodity sales from purchases (loss) [1]	**(2,376)**	32,813	**(5,490)**	38,895
Realized hedging gain (loss) on purchases	**3,113**	(29,435)	**11,216**	(28,699)
Net commodity sales from purchases after hedging[1]	**737**	3,378	**5,726**	10,196
$/boe – before hedging	**(1.22)**	21.64	**(0.92)**	9.18
$/boe – after hedging	**0.37**	2.23	**0.96**	2.41

1 – Non-GAAP and other financial 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 and Other Financial Measures" section of this MD&A.

In order to mitigate the cost of transportation service in excess of current production needs, the Company purchases available natural gas volumes in Alberta and/or British Columbia and resells these volumes in Chicago. Other than during wildfire related production shut-ins in May, the Company was able to successfully purchase and fill the balance of its Alliance firm transportation commitment during the nine months ended September 30, 2023, not met through proprietary field production and temporarily assigned volumes. The Company also enters into risk management contracts associated with purchased natural gas volumes for resale to secure the pricing difference between the Alberta and Chicago sales points. To date, this strategy has resulted in positive net commodity sales from purchases after hedging while allowing the Company to meet its excess transportation commitments on the Alliance pipeline.

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

Total net commodity sales from purchases have declined during the three and nine months ended September 30, 2023 relative to the comparable periods in 2022. As the Company increases production levels, the quantity of production required to be purchased to fill Alliance pipeline commitments, and the risk associated with take or pay pipeline obligations and marketing of purchased volumes is reduced.

In the three and nine months ended September 30, 2023, the Company realized losses of $2.4 million and $5.5 million, respectively, on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system. Including the offsetting impact of risk management contracts associated with natural gas differentials in Chicago, the Company realized overall marketing income of $0.7 million and $5.7 million for the three and nine months ended September 30, 2023, respectively (2022: $3.4 million and $10.2 million, respectively).

Risk management contracts

In an effort to mitigate commodity price fluctuations for natural gas, crude oil and natural gas liquids, the Company enters into financial commodity contracts as part of its risk management program which is designed to protect cash flows from its base production and help ensure sufficient capital and liquidity is available to execute its strategy and complete its Company's planned capital development program.

Risk management contracts are entered into at prices that the Company believes enhance the probability of capital projects meeting or exceeding their targeted financial return hurdles. All risk management contracts are entered into in accordance with the Company's risk management policy, ensuring the Company retains its ability to cover all outstanding risk management liabilities when they arise. The Company regularly reviews its credit exposure to the counterparties that it enters into risk management contracts with.

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Risk management:				
Unrealized (loss) gain	**(38,802)**	26,266	**(1,104)**	(18,439)
Realized gain (loss)	**5,514**	(55,108)	**23,016**	(100,597)
Total (loss) gain on risk management	**(33,288)**	(28,842)	**21,912**	(119,036)
Unrealized (loss) gain ($/boe)	**(19.88)**	17.32	**(0.18)**	(4.35)
Realized gain (loss) ($/boe)	**2.82**	(36.33)	**3.85**	(23.73)

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

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Realized gain (loss) on production	**2,511**	(25,190)	**13,341**	(72,339)
Realized gain (loss) on purchases	**3,113**	(29,435)	**11,216**	(28,699)
Realized (loss) gain on foreign exchange	**(110)**	(483)	**(1,541)**	441
Total realized gain (loss)	**5,514**	(55,108)	**23,016**	(100,597)
Realized gain (loss) on production ($/boe)	**1.29**	(16.60)	**2.23**	(17.06)
Realized gain (loss) on purchases ($/boe)	**1.59**	(19.41)	**1.88**	(6.77)
Realized (loss) gain on foreign exchange ($/boe)	**(0.06)**	(0.32)	**(0.26)**	0.10

For the three and nine months ended September 30, 2023, the Company recorded realized gains on risk management contracts of $5.5 million and $23.0 million, respectively. Approximately 56% of the third quarter and 49% of the nine month gains were related to natural gas volumes purchased for resale required to meet pipeline commitments in excess of the Company's production needs, where the Company hedges price differences between Chicago and Alberta markets at the time of contracting third party natural gas purchases.

Gains were realized on production hedges in the three and nine months ended September 30, 2023 relative to significant losses in the comparative periods of 2022 as a result of higher hedged prices relative to benchmark pricing, with significantly higher benchmark pricing in 2022 driving prior year losses. When compared to 2022, gains related to volumes purchased to fill pipeline capacity increased as a result of the differential between Chicago and AECO prices narrowing relative to hedged rates (see – Net commodity sales from purchases).

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, crude oil, and foreign exchange 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) income and comprehensive (loss) income.

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 unrealized loss on risk management of $38.8 million and $1.1 million during the three and nine months ended September 30, 2023, represents changes in the fair value of risk management contracts outstanding at the end of those periods bringing the portfolio to a liability (net payable) of $18.9 million as at September 30, 2023 (December 31, 2022: net payable of $17.8 million).

The Company has the following commodity risk management contracts outstanding as of September 30, 2023:

Type		Q4 2023	2024	2025
Crude oil [1]				
WTI fixed price	bbl/d	1,100	500	—
WTI buy put	bbl/d	4,483	2,971	1,000
WTI buy call [4]	bbl/d	500	—	—
WTI sell call	bbl/d	4,000	2,229	1,000
WTI swap average	US$/bbl	$70.41	$70.62	$—
WTI buy put average	US$/bbl	$70.65	$67.68	$67.50
WTI buy call average [4]	US$/bbl	$85.00	$—	$—
WTI sell call average	US$/bbl	$85.26	$78.71	$77.38

Type		Q4 2023	2024	2025
Natural gas [1,2]				
NYMEX Henry Hub fixed price	MMBtu/d	10,500	3,333	—
NYMEX Henry Hub buy put	MMBtu/d	37,000	29,792	14,167
NYMEX Henry Hub sell call	MMBtu/d	29,500	21,667	14,167
NYMEX Henry Hub buy call [4]	MMBtu/d	5,000	—	—
NYMEX Henry Hub fixed price average	US$/MMBtu	$3.24	$3.18	$—
NYMEX Henry Hub buy put average	US$/MMBtu	$3.86	$3.25	$3.31
NYMEX Henry Hub sell call average	US$/MMBtu	$4.36	$4.03	$4.87
NYMEX Henry Hub buy call average [4]	US$/MMBtu	$7.00	$—	$—
Natural gas transportation [1,2,3]				
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	8,333	—	—
Sell GDD Chicago basis (to NYMEX Henry Hub) [5]	MMBtu/d	(8,333)	—	—
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	$(1.28)	$—	$—
GDD Chicago basis (to NYMEX Henry Hub) average [5]	US$/MMBtu	$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 exposure to basis pricing differentials between AECO and Chicago arising from firm transportation commitments.
4 – The Company has entered into select bought call transactions in order to preserve potential upside associated with swap and collar transactions over the same period.
5 – Gas Daily Daily ("GDD") pricing represents the daily natural gas settlement price in Chicago.

The Company has the following foreign exchange risk management contracts outstanding at September 30, 2023:

Type		Q4 2023	2024	2025
Foreign exchange				
Sell USD CAD (monthly average)	US$	15.5 MM	13.0 MM	16.5 MM
USD CAD buy put	US$	15.0 MM	11.0 MM	2.5 MM
USD CAD sell call	US$	15.0 MM	11.0 MM	2.5 MM
USD CAD fixed sell rate		$1.34	$1.34	$1.34
USD CAD put rate		$1.32	$1.32	$1.33
USD CAD call rate		$1.36	$1.36	$1.38

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

The components of the Company's total risk management contract liability outstanding are as follows:

$000s	September 30, 2023	December 31, 2022
Short term risk management asset	—	2,554
Short term risk management liability	**(13,499)**	(13,687)
Long term risk management liability	**(5,372)**	(6,634)
Total risk management contracts liability	**(18,871)**	(17,767)

$000s	September 30, 2023	December 31, 2022
Liability on produced volumes	**(12,177)**	(17,466)
Asset on purchased volumes	**460**	131
Liability on foreign exchange contracts	**(7,154)**	(432)
Total risk management liability	**(18,871)**	(17,767)

Subsequent to September 30, 2023, the Company entered into the following risk management contracts:

Type		Q4 2023	2024	2025	2026
Crude oil contracts [1,2]					
WTI fixed price	bbl/d	—	—	250	—
WTI buy put	bbl/d	—	250	458	—
WTI sell call	bbl/d	—	250	458	—
WTI swap average	US$/bbl	$—	$—	$74.00	$—
WTI buy put average	US$/bbl	$—	$74.00	$72.33	$—
WTI sell call average	US$/bbl	$—	$80.00	$79.38	$—
Natural gas [1,2]					
NYMEX Henry Hub buy put	MMBtu/d	—	—	2,500	2,083
NYMEX Henry Hub sell call	MMBtu/d	—	—	2,500	2,083
NYMEX Henry Hub buy put average	US$/MMBtu	$—	$—	$3.35	$3.35
NYMEX Henry Hub sell call average	US$/MMBtu	$—	$—	$5.00	$5.00
Natural gas transportation [1,2,3,4]					
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	20,000	25,000	—	—
Sell GDD Chicago basis (to NYMEX Henry Hub) [5]	MMBtu/d	(20,000)	(25,000)	—	—
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	$(1.23)	$(1.27)	$—	$—
GDD Chicago basis (to NYMEX Henry Hub) average [5]	US$/MMBtu	$0.13	$(0.01)	$—	$—

1 – Prices per unit and volumes per day are represented at the average amounts for the period.
2 – Additional contracts were layered into the Company's existing risk management portfolio as part of the Company's risk management policy. The Company does not seek to speculate on commodity price movements through the hedging program.
3 – All basis swap pricing is in $USD / unit relative to NYMEX Henry Hub benchmark pricing.
4 – Natural gas transportation hedges relate to exposure to basis pricing differentials between AECO and Chicago arising from firm transportation commitments.
5 – Gas Daily Daily ("GDD") pricing represents the daily natural gas settlement price in Chicago.

Royalty expense

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Royalty expense	**5,360**	18,973	**27,919**	31,131
As a % of revenue	**5.7 %**	16.0 %	**9.4 %**	9.0 %
$/boe	**2.75**	12.51	**4.68**	7.34

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties for the three and nine months ended September 30, 2023 decreased to $5.4 million and $27.9 million, respectively, as compared to $19.0 million and $31.1 million in the comparative periods of 2022. The Company continues to benefit from Alberta's drilling and completion cost allowance program, which provides a 5% royalty rate on a well's initial production until the well's cumulative revenue from all hydrocarbon products equals a maximum threshold. Royalties as a percentage of revenue of 5.7% during the three months ended September 30, 2023 decreased relative to the comparative period in 2022 due to a gas cost allowance recovery combined with a higher proportion of production coming from new wells which benefit from rate reductions relative to older wells reverting to higher base royalty rates. Royalties as a percentage of revenue of 9.4% for the nine months ended September 30, 2023 was consistent with the comparative period in 2022.

Operating expenses

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Operating expenses	**17,895**	16,873	**50,822**	46,805
$/boe	**9.17**	11.13	**8.51**	11.04

Operating costs include amounts incurred to extract commodities to the surface including expenditures for field operators, gas and liquids processing, gathering and compression, utilities, chemicals and maintenance related costs. Operating costs during the three and nine months ended September 30, 2023 increased by 6% to $17.9 million and by 9% to $50.8 million, respectively, due to increased production volumes and higher levels of activity.

On a per barrel basis, operating costs decreased to $9.17/boe and $8.51/boe for the three and nine months ended September 30, 2023, respectively, compared to $11.13/boe and $11.04/boe in the comparative periods of 2022. Operating costs per boe decreased over both periods as a result of higher production volumes being accommodated by existing Company processing facilities, demonstrating the value of Company owned and operated infrastructure. In the third quarter of 2023, per barrel savings were partially offset by operating costs associated with additional workovers and downtime associated with the expansion at the Company's 10-29 processing facility.

Transportation expenses

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Transportation expenses	**10,913**	10,060	**33,735**	22,628
$/boe	**5.59**	6.63	**5.65**	5.34

Transportation expenses are incurred to deliver oil and natural gas commodities from the Company's production sites to the delivery point of sale. The Company has contracted for firm transportation service on the Alliance pipeline system from Alberta to Chicago and on the NGTL system in Alberta. The balance of costs pertains to trucking charges and pipeline fees related to oil, NGL and condensate transportation charges.

Per barrel transportation expenses decreased 16% to $5.59/boe during the third quarter of 2023 from $6.63/boe during the comparable period in 2022. The decrease is, in part, a reflection of additional transportation charges incurred during 2022 as a result of NGL production exceeding contracted firm pipeline commitments which resulted in a portion of NGL volumes being transported at a higher cost posted rate. For the nine months ended September 30, 2023 per barrel costs increased 6% to $5.65/boe as compared to $5.34/boe for the first nine months of 2022. Higher transportation costs resulted from the Company flowing a higher proportion of natural gas production to the higher cost Alliance pipeline in 2023.

Adjusted funds flow from operations

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Cash flows from operating activities	**60,294**	91,710	**181,814**	155,822
Net change in non-cash working capital from operating activities	**(5,454)**	(42,916)	**(8,076)**	5,042
Asset retirement obligation expenditures	**474**	423	**3,876**	1,587
Adjusted funds flow from operations [1]	**55,314**	49,342	**177,614**	162,576
$/boe	**28.34**	32.53	**29.75**	38.35

1 – Non-GAAP and other financial 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 and Other Financial Measures" section of this MD&A.

Adjusted funds flow from operations during the three and nine months ended September 30, 2023 increased to $55.3 million and $177.6 million relative to the comparative periods in 2022 ($49.3 million and $162.6 million, respectively.)

On a per barrel basis, adjusted funds flow from operations of $28.34/boe and $29.75/boe were 13% and 22% lower, respectively, during the three and nine months ended September 30, 2023 relative to the comparable periods of 2022. Declines in 2023 were driven by the reduction in adjusted operating netbacks described above and increased financing costs resulting from higher average debt levels outstanding at higher interest rates.

The Company's cash flow from operating activities was $60.3 million and $181.8 million for the three and nine months ended September 30, 2023. Cash flow from operating activities has been adjusted for the net change in non-cash working capital from operating activities and asset retirement obligation expenditures in the determination of adjusted funds from operations.

Free funds flow from operations

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Adjusted funds flow from operations [1]	**55,314**	49,342	**177,614**	162,576
Capital expenditures [1]	**(63,141)**	(60,461)	**(230,575)**	(167,021)
Free funds flow deficiency from operations [1]	**(7,827)**	(11,119)	**(52,961)**	(4,445)
$/boe	**(4.01)**	(7.33)	**(8.87)**	(1.05)

1 – Non-GAAP and other financial 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 and Other Financial Measures" section of this MD&A.

During the three and nine months ended September 30, 2023, the Company had a free funds flow deficiency of $7.8 million and $53.0 million relative to a deficiency of $11.1 million and $4.4 million in the comparative periods of 2022. The increased deficiency in 2023 resulted from the Company continuing to execute a capital program aimed at generating short and longer-term production growth and cash-flow through development of its existing reserve base and investment in infrastructure required to grow production in future periods.

The Company has been able to fund its capital plan through funds flow from operations and available credit facilities. The Company continuously monitors liquidity and financial performance to ensure sufficient balance sheet strength is maintained. If required, the Company has the ability to adjust future capital spending plans to manage liquidity and/or balance sheet constraints.

General and administrative ("G&A") expenses

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Gross G&A expenses	**4,958**	4,187	**17,352**	14,806
Less capitalized G&A	**(757)**	(652)	**(2,818)**	(1,788)
G&A Expenses	**4,201**	3,535	**14,534**	13,018
$/boe	**2.15**	2.33	**2.43**	3.07

For the three and nine months ended September 30, 2023, the Company incurred gross G&A expenses of $5.0 million and $17.4 million, respectively, as compared to $4.2 million and $14.8 million in the comparable periods of 2022, with the increases attributable to Company growth and increased activity levels since 2022.

On a per boe basis, G&A expenses for the three and nine months ended September 30, 2023 decreased by 8% and 21%, respectively, primarily as a result of production growth.

The Company's G&A expense encompasses corporate activity, the upstream business, and the development of the power business, including the development of renewable and natural gas-fired power generation projects. In addition, the Company continues to evaluate business development opportunities in upstream, power, carbon capture technology and hydrogen production. Administrative and other overhead costs related to development of these activities are also captured within G&A.

Share-based compensation expenses

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Share-based compensation expenses	**1,027**	2,277	**5,076**	8,275
$/boe	**0.53**	1.50	**0.85**	1.95

Share-based compensation is the compensation expense recognized for non-cash equity-settled incentive plans including stock options and performance warrants and cash-settled incentive plans including deferred share units, performance share units and restricted share units. The compensation expense for equity-settled awards 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. The compensation expense related to cash-settled awards is calculated using the fair value method based on the trading price of the Company's shares at the end of each reporting period after adjusting for an estimated forfeiture rate, vesting period, and any applicable performance criteria with changes in fair value recognized as share-based compensation expense.

Share-based compensation was $1.0 million and $5.1 million for the three and nine months ended September 30, 2023 compared to $2.3 million and $8.3 million in the comparable prior year periods due to the graded nature of vesting with the decline on a per barrel basis also attributable to higher production levels in 2023.

Finance costs

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Interest and bank charges	**4,511**	2,313	**11,992**	4,791
Accretion of asset retirement obligations	**956**	697	**2,676**	1,570
Interest on lease obligations	**428**	214	**872**	230
Deferred financing amortization	**161**	323	**754**	969
Unrealized gain on foreign exchange	**(307)**	(1,881)	**(139)**	(1,871)
Total finance costs	**5,749**	1,666	**16,155**	5,689
$/boe	**2.95**	1.10	**2.71**	1.34

The Company has a $375 million senior secured extendible revolving facility (the "Credit Facility") with a syndicate of banks. As at September 30, 2023 the Company had drawn $180.4 million on the facility (September 30, 2022 - $102.1 million). The increase in financing costs for the three and nine months ended September 30, 2023 is associated with higher average debt levels and higher interest rates when compared to the comparable prior year periods. During the three and nine months ended September 30, 2023 the average outstanding debt was approximately $92 million and $68 million higher than during the same periods in 2022. Average interest rates were approximately 8.1% for the nine months ended September 30, 2023 (2022 - approximately 5.0%).

Depletion and Depreciation

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Depletion	**30,026**	18,031	**88,699**	47,000
Depreciation	**525**	384	**1,407**	1,067
Total depletion and depreciation	**30,551**	18,415	**90,106**	48,067
$/boe	**15.65**	12.14	**15.09**	11.34

Increases in depletion per barrel for the three and nine months ended September 30, 2023 are attributable to a greater depletable base arising from an increase in year over year estimated future development costs as outlined in the Company's 2022 reserve report. Increases resulted from inflationary pressures and other assumptions utilized by external reserve evaluators, partially offset by an increase in proved and probable reserves assigned. During the third quarter, the Company disposed of non-core assets within the Simonette area which increased the depletion rate within Simonette through a reduction of future development costs of $0.2 billion and an approximately 12% reduction in total proved plus probable reserves.

The Company recognized depletion of $30.0 million and $88.7 million for the three and nine months ended September 30, 2023 (2022 - $18.0 million and $47.0 million respectively) with increases as a result of higher depletion per barrel combined with increased production levels in the respective periods of 2023.

Income taxes

During the nine months ended September 30, 2023, the Company incurred approximately $0.2 million in income taxes relating to the Company's United States subsidiary. The Company did not pay any Canadian income taxes in 2023 and does not expect to be taxable in Canada in the near future. As of September 30, 2023, the Company recognized a deferred tax asset of $8.8 million. Deferred tax assets have been recognized net of deferred tax liabilities. The Company's estimated tax pools as at September 30, 2023, are as follows:

Category	Deductibility	$000s
Canadian oil and gas property expense ("COGPE")	10%	204,034
Successored COGPE	10%	1,088
Canadian development expense ("CDE")	30%	195,763
Successored CDE	30%	67,526
Canadian exploration expense ("CEE")	100%	—
Successored CEE	100%	10,032
Undepreciated capital cost ("UCC")	Primarily 25%, declining balance	175,802
Non-capital losses	100%	204,326
Share/Debt issue costs	5-year straight line	2,616
Other	Various	363
Total estimated tax pools		861,550

Asset retirement obligations

The Company's asset retirement obligations ("ARO") 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. The Company estimates the total future cash flows to settle its ARO is $117.5 million, or $183.1 million inflated at 1.75% and undiscounted. These cash flows have been discounted using a risk-free interest rate of 3.81% to arrive at the present value estimate of $75.4 million.

There is approximately $26.1 million (December 31, 2022: $31.7 million) of abandonment and reclamation costs associated with inactive wells or facilities where there are no active operations or attributed reserves. Kiwetinohk is currently working on an abandonment program to reduce significantly the inactive decommissioning liabilities over the next five to seven years which exceeds the minimum regulatory requirements.

Select quarterly information

($000s except per share and production)	2023			2022				2021
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Production (average boe/d)	**21,218**	20,432	23,996	24,745	16,487	16,810	13,253	12,422
Commodity sales from production	**94,432**	83,935	119,421	159,457	122,644	137,931	79,866	70,267
Commodity sales from purchases	**19,464**	17,475	20,498	47,902	77,623	82,429	60,598	58,398
Cash flow from operating activities	**60,294**	41,360	80,160	87,028	91,710	38,780	25,332	25,509
Per share (basic)	**1.37**	0.94	1.81	1.97	2.08	0.88	0.58	0.58
Per share (diluted)	**1.36**	0.93	1.79	1.94	2.05	0.87	0.58	0.58
Net (loss) income	**(12,056)**	21,701	53,949	115,308	55,379	44,854	(24,552)	44,306
Per share (basic)	**(0.27)**	0.49	1.22	2.61	1.26	1.02	(0.56)	1.02
Per share (diluted)	**(0.27)**	0.49	1.21	2.57	1.24	1.01	(0.56)	1.02

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 address contingencies and execute on strategic business opportunities. The Company relies on cash flow from operating activities, available funding capacity 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 remaining 2023 capital program.

Credit Facility

On May 31, 2023 the Company completed the annual borrowing base review of the consolidated Credit Facility and confirmed no changes to the borrowing base of $375.0 million. The borrowing base is comprised of an operating facility of $65.0 million and a syndicated facility of $310.0 million.

At September 30, 2023, $180.4 million before deferred financing costs (December 31, 2022 - $119.7 million) was outstanding on the Credit Facility along with $88.9 million (December 31, 2022 - $40.8 million) in letters of credit issued to support transportation and other commitments, of which, $66.2 million has been provided for through the EDC facility (see below), and the remaining $22.7 million are held and reduce the available operating facility capacity.

$000s	Borrowing capacity	Drawn	Letters of credit	Available Capacity [1]
Credit Facility	375,000	180,350	22,732	**171,918**
EDC Facility	75,000	—	66,149	**8,851**
Total Capacity [1]				**180,769**

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

$000s	September 30, 2023	December 31, 2022
Credit facility drawn	**180,350**	119,738
Deferred financing costs	**(1,073)**	(539)
Loans and borrowings	**179,277**	119,199
Adjusted working capital deficit (surplus) [1]	**8,240**	3,105
Net debt [1]	**187,517**	122,304
Annualized adjusted funds flow from operations [1]	**279,120**	264,082
Net debt to annualized adjusted funds flow from operations [1]	**0.67**	0.46

1 – Non-GAAP and other financial 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 and Other Financial Measures" section of this MD&A.

The Credit Facility is a 364-day committed facility available on a revolving basis which was extended until May 31, 2024, 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, 2025. 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 ratio of the Company's debt to earnings before interest, taxes, depreciation and amortization ("bank EBITDA ratio"): 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 percent to 1.5625 percent based on the Company's bank EBITDA ratio.

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

The Company plans to continue using the Credit Facility for working capital purposes and to fund go forward capital plans in advance of cash flow from new investments and targets a net debt to last-twelve-months of adjusted funds flow from operations ratio of no more than 1.0 times (September 30, 2023 - 0.67 times).

EDC letter of credit facility

On June 5, 2023, Kiwetinohk amended and increased the unsecured demand revolving letter of credit facility (the "LC Facility") with Export Development Canada ("EDC") from $15.0 million to $75.0 million. Kiwetinohk's obligations under the LC Facility are supported by a performance security guarantee ("PSG") granted by EDC to the Credit Facility lender to guarantee the payment of certain amounts in respect of LCs. The PSG is valid to May 31, 2024 and may be extended from time-to-time at the option of Kiwetinohk and with the agreement of EDC. During the third quarter, Kiwetinohk provided letters of credit to the AESO as evidence that the Company has sufficient financial capacity to pay the Generating Unit Owner's Contribution ("GUOC") required for its power projects. By posting credit under this facility, the Company met all conditions required to ensure that its current portfolio of power projects would not be subject to the new AESO cluster study review process (see power development). At September 30, 2023, the Company has $8.8 million of capacity remaining under the LC Facility (December 31, 2022 - $0.6 million).

Base shelf prospectus

The Company filed a short-form base shelf prospectus ("Prospectus") in April 2022 with no immediate plan to raise equity or debt. The prospectus provides 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. 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 and an unlimited number of preferred shares issuable in series.

On December 20, 2022, the Company announced the approval of its normal course issuer bid ("NCIB") to purchase and cancel up to 2.2 million Common Shares over a 12-month period, commencing December 22, 2022. During the nine months ended September 30, 2023, the Company purchased 473,295 Common Shares at a total cost of $6.0 million (an average price of $12.68 per share). The Company weighs the benefits to shareholders of allocating funds to new capital expenditures versus utilizing the NCIB program and will continue to monitor the use of the NCIB program throughout the remainder of the year with the amount and timing of any purchases depending among other things, on the share price, commodity prices and overall budget projections.

(000s)	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Weighted average shares outstanding				
Basic	**43,885**	44,114	**44,059**	44,004
Diluted	**44,390**	44,795	**44,555**	44,491
Outstanding securities				
Common shares	**43,786**	44,117	**43,786**	44,117
Stock options[1]	**2,730**	2,646	**2,730**	2,646
Performance warrants[1]	**6,779**	7,709	**6,779**	7,709
Total diluted outstanding securities	**53,295**	54,472	**53,295**	54,472

1 - Balance presented includes all potentially dilutive stock options and performance warrants issued and outstanding and is not limited to those currently available for exercise. Refer to Note 12 of the Condensed Consolidated Interim Financial Statements for further information regarding share based compensation plans.

At November 7, 2023, the Company has 43,726,270 Common Shares and no preferred shares outstanding.

Commitments, contractual obligations, and provisions

$ millions	2023	2024	2025	2026	2027	Thereafter
Accounts payable	61.5	—	—	—	—	—
Contingent payment consideration	—	1.7	—	—	—	—
Cash-settled compensation liability [1]	—	1.0	0.5	0.1	—	1.1
Loans and borrowings [2]	—	—	180.4	—	—	—
Risk management contracts	3.1	13.2	2.6	—	—	—
Gathering, processing and transport	18.9	78.3	68.9	15.7	17.2	40.1
Natural gas purchases	8.7	16.7	—	—	—	—
Upstream and corporate lease liabilities	0.4	1.8	2.2	2.2	2.2	7.9
Power lease liabilities[3]	—	2.0	1.3	1.3	1.3	27.2
Power construction	1.0	—	—	—	—	—
Other	—	0.4	0.4	0.4	0.4	0.7
Total	93.6	115.1	256.3	19.7	21.1	77.0

1 – cash outflows relating to the DSU cash-settled compensation liability will be paid when each director retires. The Company has no available information to estimate the year of cash outflow and therefore the entirety of the DSU expected outflow has been assigned to "Thereafter".
2 – represents current debt drawn repaid at the end of the Credit Facility term
3 – The Company has not reached a final investment decision ("FID") on power projects as of September 30, 2023. The Company has the ability to terminate the lease and remove this financial obligation if FID is not achieved.

The Company currently has natural gas transportation commitments of approximately 120.0 MMcf per day to deliver gas to Chicago on the Alliance pipeline through October 2025.

The Company currently has secured 27,000 GJ per day of gas supply (approximately 23.6 MMcf per day) from natural gas producers through September 2024, allowing the Company to fully utilize its remaining Alliance pipeline capacity after taking into account deliveries of its own production.

Lease liabilities represent the undiscounted payments required under lease obligations as described in Note 5 of the condensed consolidated interim financial statements. Power construction commitments are the expected payments to complete a full scale geotechnical and pile test program required to refine and finalize contract prices for the Homestead project.

Related party information

For the three and nine months ended September 30, 2023, the Company incurred a total of $0.2 million and $0.5 million, respectively (September 30, 2022 – $0.2 million and $1.3 million), in the following related party transactions:

- The Company has retained a law firm to provide legal services on corporate matters. A director of the Company is a partner of this law firm; and
- The Company has engaged an energy information services company to assist in the evaluation of prospective upstream oil and gas properties. A director of the Company is the Chairman of the Board of Directors 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. There are no contractual commitments associated with related parties.

Environment, social and governance

Kiwetinohk regularly reviews its environmental, social and governance ("ESG") risks and management strategies, and published its 2023 ESG report (for the 2022 reporting year) on November 9, 2023 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. There were no significant changes in key risks identified during the three and nine months ended September 30, 2023. For additional information on risk factors, refer to the Company's audited financial statements as at and for the year ended December 31, 2022 and the Company's Annual Information Form ("AIF") dated March 7, 2023 available on the Company's website at www.kiwetinohk.com or on the SEDAR+ website at www.sedarplus.ca.

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 its 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.

Control environment

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

The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") are responsible for internal controls over financial reporting to be designed under their supervision. Given the size of the Company and high involvement of the CEO and CFO in the day-to-day operating activities of the Company, there are appropriate disclosure controls and procedures in place to provide reasonable assurance that (i) material information relating to the Company is made known to the Company's CEO and CFO by others, and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed and reported within the time periods specified in securities legislation.

There were no changes in the Company's internal controls during the period beginning on July 1, 2023, and ending on September 30, 2023, 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, 2022 financial statements. Certain accounting policies require that management make appropriate decisions with respect to the formulation of estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, and expenses. Management reviews its estimates on a regular basis. The emergence of new information and changed circumstances may result in actual results or changes to estimate amounts that differ materially from current estimates. There have been no material changes to the Corporation's critical accounting estimates, judgments and policies during the three and nine months ended September 30, 2023.

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.

Financial instruments carried at fair value include contingent payment consideration, share based compensation liability, and risk management contracts. Contingent payment consideration, share based compensation liability and risk management contracts are classified as a Level 2 measurement in the fair value measurement hierarchy. All other financial instruments are measured at amortized cost.

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 accounts receivable and risk management contracts.

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

Liquidity risk

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

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 condensed consolidated interim statement of net (loss) income and comprehensive (loss) income to the extent the Company has outstanding financial instruments.

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

Off-balance sheet arrangements

Except as disclosed in the Financial Statements, the Company has not entered into any guarantee or off-balance sheet arrangements that would materially impact the financial position or results of operations as at September 30, 2023.

Other

Management changes

On August 24, 2023 the Company announced Fareen Sunderji as the new President of its power division. Fareen joins Kiwetinohk from a major energy infrastructure company where she held various leadership positions over the last decade in the power and natural gas business in engineering, supply chain, project execution, operations, commercial, asset integration and divestitures. Fareen holds a degree in Electrical Engineering from the University of Alberta and an MBA from Yale School of Management.

Non-GAAP and other financial measures

Throughout this MD&A and in other materials disclosed by the Company, the Company uses various specified financial measures including "non-GAAP financial measures", "non-GAAP financial ratios" and "capital management measures", as defined in National Instrument 52-112 Non-GAAP and Other Financial Measures Disclosure and explained in further detail below. These non-GAAP and other financial 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.

Non-GAAP Financial Measures

Operating netback & adjusted operating netback

"Operating netback" is calculated as commodity sales from production less royalty, operating, and transportation expenses. The Company 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. The table below reconciles operating netback and adjusted operating netback to the most directly comparable GAAP measure, commodity sales from production:

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Commodity sales from production	**94,432**	122,644	**297,788**	340,441
Royalty expenses	**(5,360)**	(18,973)	**(27,919)**	(31,131)
Operating expenses	**(17,895)**	(16,873)	**(50,822)**	(46,805)
Transportation expenses	**(10,913)**	(10,060)	**(33,735)**	(22,628)
Operating netback	**60,264**	76,738	**185,312**	239,877
Realized gain (loss) on risk management	**2,401**	(44,810)	**11,800**	(71,898)
Realized gain (loss) on risk management contracts - purchases	**3,113**	(55,108)	**11,216**	(28,699)
Net commodity sales from purchases (loss)	**(2,376)**	77,623	**(5,490)**	38,895
Adjusted operating netback	**63,402**	54,443	**202,838**	178,175

Capital expenditures, net acquisitions (dispositions) & capital expenditures and net acquisitions (dispositions)

“Capital expenditures” is calculated as cash used in investing activities, excluding changes in non-cash working capital, settlements of contingent consideration, acquisitions and dispositions. The Company uses capital expenditures to monitor its investment in property, plant and equipment, exploration and evaluation and projects in development. "Net acquisitions (dispositions)" is calculated as cash used in acquisitions and proceeds from disposition. “Capital expenditures and net acquisitions (dispositions)” is equal to the sum of capital expenditures and net acquisitions (dispositions). The table below reconciles capital expenditures, net acquisitions (dispositions) and capital expenditures and net acquisitions (dispositions) to the most directly comparable GAAP measure, cash flow used in investing activities:

$000s	Q3 2023	Q3 2022	YTD 2023	YTD 2022
Cash flow used in investing activities	**53,715**	117,773	**235,987**	226,809
Net change in non-cash investing working capital	**7,781**	3,369	**2,843**	4,035
Settlement of contingent consideration	**—**	(1,500)	**(10,250)**	(6,500)
Capital expenditures and net acquisitions (dispositions)	**61,496**	119,642	**228,580**	224,344
Cash used in acquisitions	**(855)**	(59,181)	**(1,286)**	(61,681)
Proceeds from disposition	**2,500**	—	**3,281**	4,358
Net (dispositions) acquisitions	**1,645**	(59,181)	**1,995**	(57,323)
Capital expenditures	**63,141**	60,461	**230,575**	167,021

Net commodity sales from purchases & Net commodity sales from purchases after hedging

Commodity sales from purchases and commodity purchases, transportation and other is revenue from the sale of purchased natural gas less associated commodity purchases, transportation expense and related marketing fees. “Net commodity sales from purchases” is used as a key measure of how the Company is managing its take or pay pipeline commitments. The Company also enters into risk management contracts associated with marketing activities to protect the basis differential between the Alberta and Chicago sales points related to net commodity sales from purchase. “Net commodity sales from purchases after hedging” includes the impact of these basis differential contracts. The Company has disclosed the reconciliation of net commodity sales from purchases & net commodity sales from purchases after hedging to the most directly comparable GAAP measure, commodity sales from purchases, in this MD&A within the Results of Operations section.

Non-GAAP Financial Ratios

Operating netback per boe & adjusted operating netback per boe

“Operating netback per boe” and “adjusted operating netback per boe” is calculated as operating netback and adjusted operating netback, respectively, divided by total production for the period. Operating netback per boe and adjusted operating netback per boe are key industry benchmarks and assist management with evaluating operating performance and efficiency on a comparable basis. The Company has disclosed the calculations of operating netback per boe & adjusted operating netback per boe in this MD&A within the Results of Operations section.

Adjusted funds flow from operations per boe

"Adjusted funds flow from operations" is cash flow from operating activities before changes in net change in non-cash working capital from operating activities, asset retirement obligations, and acquisition costs divided by total production for the period. Management considers adjusted funds flow from operations per boe 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. The composition of adjusted funds flow from operations is disclosed in this MD&A within the Results of Operations section.

Capital Management Measures

Adjusted funds flow from operations

"Adjusted funds flow from operations" is cash flow from operating activities before changes in net change in non-cash working capital from operating activities, asset retirement obligations, and acquisition costs. Management considers adjusted funds flow from 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. The composition of adjusted funds flow from operations is disclosed in this MD&A within the Results of Operations section.

Free funds flow (deficiency) from operations

"Free funds flow (deficiency) from operations" is adjusted funds flow from 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. The composition of Free funds flow (deficiency) from operations is disclosed in this MD&A within the Results of Operations section.

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. The following table includes the composition of adjusted working capital surplus (deficit).

$000s	September 30, 2023	December 31, 2022
Current assets	**64,688**	96,062
Current liabilities	**(86,427)**	(110,300)
Working capital deficit	**(21,739)**	(14,238)
Short term risk management contracts net liability (asset)	**13,499**	11,133
Adjusted working capital deficit	**(8,240)**	(3,105)

Net debt and net debt to annualized adjusted funds flow from operations or adjusted funds flow from operations

"Net debt" is comprised of loans and borrowings plus adjusted working capital surplus (deficit) and represents the Company's net financing obligations. Net debt is used by management to provide a more complete understanding of the Company's capital structure and provides a key measure to assess the Company's liquidity. "Net debt to annualized adjusted funds flow from operations" is a liquidity ratio that represents the Company's ability to cover its net debt with its adjusted funds flow from operations. Net debt to annualized adjusted funds flow is calculated as net debt divided by the trailing four quarter adjusted funds flow from operations. The composition of Net debt and net debt to annualized adjusted funds flow from operations is disclosed in this MD&A within the Capital resources and liquidity section.

Supplementary Financial Measures

This MD&A contains supplementary financial measures expressed as: (i) cash from operating activities, adjusted funds flow and free cash flow on a per share – basic and per share – diluted basis, (ii) realized prices, petroleum and natural gas sales, adjusted funds flow, revenue, royalties, operating expenses, transportation, realized loss on risk management, and net commodity sales from purchases on a $/bbl, $/Mcf or $/boe basis and (iii) royalty rate.

Cash from operating activities, adjusted funds flow and free cash flow on a per share – basic and diluted basis are calculated by dividing the cash from operating activities, adjusted funds flow or free cash flow, as applicable, over the referenced period by the weighted average basic or diluted shares outstanding during the period determined under IFRS.

Metrics presented on a $/bbl, $/Mcf or $/boe basis are calculated by dividing the respective measure, as applicable, over the referenced period by the aggregate applicable units of production (bbl, Mcf or boe) during such period.

Royalty rate is calculated by dividing royalties by petroleum and natural gas sales less royalty and other revenue.

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 Company’s growth strategy, including 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;
- successful execution of the Company’s power projects and the impacts thereof;
- expectations regarding the bringing on-stream of the Duvernay pad and the timing thereof;
- timing for the Company’s projects, including Homestead Solar, Opal Firm Renewable and Solar 3 projects to reach FID and COD;
- submission of applications and receipt of certain regulatory approvals, including AUC transmission line approval, and timing thereof;
- the duration and outcome of AUC hearings if required on its power projects;
- the Company’s use and development of carbon hubs;
- development, evaluation and permitting of the Company’s solar and gas-fired power portfolio;
- perceived benefits of the Company’s hub projects;
- expectations regarding Kiwetinohk being the primary user of its awarded carbon hubs;
- future investigations by the Company of CCS;
- the Company's expectations regarding being taxable in Canada and the timing thereof;
- anticipated contingent payments from acquisitions and the timing thereof;
- the timing and costs of the Company's capital projects, including, but not limited to, drilling, production and completion of certain wells;

- the continuing costs of engineering and procurement;
- the anticipated outcomes of the Company’s capital program;
- expectations regarding the Company’s working capital requirements and funding of the Company’s capital program;
- estimated nameplate capacity for the Company's power development portfolio;
- anticipated well production;
- asset retirement obligations and the estimated future cash flows to settle such obligations;
- the Company’s 2023 financial and operational guidance and adjustments to the previously communicated 2023 guidance, including anticipated reduction in production, capital expenditures and general and administrative expenses;
- operating and capital costs in 2023;
- sufficiency of funds to meet the Company's working capital requirements and anticipated drilling through 2023;
- 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;
- the expected demand for, and prices and inventory levels of, petroleum products, including NGL;
- 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 impact that the Company's projects under development will have on the power grid, including its ability to create a stable and sustainable power supply;
- the Company's expectation of reduced future energy costs for Albertans;
- the Company's unique position to deliver additional value to shareholders;
- 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;
- the ability of the Company to successfully market its products;
- power project debt will be held at the project level;
- power projects will be funded by third parties, as currently anticipated; and
- the Company's operational success and results being consistent with current expectations.

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;
- the ability of the Company to proceed with the power generation projects as described or at all;
- risks of war, hostilities, civil insurrection, pandemics (including COVID-19), instability and political and economic conditions (including the ongoing Russian-Ukranian conflict) in or affecting jurisdictions in which the Company operates;
- the risks of the power and renewable industries;
- operational and construction risks associated with certain projects;
- the possibility that government policies or laws may change or governmental approvals may be delayed or withheld;
- risks relating to regulatory approvals and financing;
- uncertainty involving the forces that power certain renewable projects;
- the Company's ability to enter into or renew leases;
- potential delays or changes in plans with respect to power and solar projects or capital expenditures;
- risks associated with rising capital costs and timing of project completion;
- fluctuations in commodity and power prices, foreign currency exchange rates and interest rates;
- inflation and increased pricing and costs for services, personnel and other items;
- risks inherent in the Company's marketing operations, including credit risk;
- health, safety, environmental and construction risks;
- risks associated with existing and potential future lawsuits and regulatory actions against the Company;
- uncertainties as to the availability and cost of financing;
- the ability to secure adequate product processing, transportation, fractionation and storage capacity on acceptable terms;
- processing, pipeline and fractionation infrastructure outages, disruptions and constraints;
- financial risks affecting the value of the Company's investments; and
- other risks and uncertainties described elsewhere in this document and in Kiwetinohk’s other filings with Canadian securities authorities.

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

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

Future Oriented Financial Information

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

Abbreviations

$/bbl	dollars per barrel
$/boe	dollars per barrel equivalent
$/GJ	dollars per gigajoule
$/Mcf	dollars per thousand cubic feet
AECO	the daily average benchmark price for natural gas at the physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
AESO	Alberta Electric Systems Operator
AIF	Annual Information Form
AUC	Alberta Utilities Commission
bbl/d	barrels per day
boe	barrel of oil equivalent, including crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe per six Mcf of natural gas)
boe/d	barrel of oil equivalent per day
CCS	Carbon Capture and Storage
COD	Commercial Operations Date
DI	daily index
EBITDA	earnings before interest, income taxes, depreciation, depletion, and amortization
FEED	Front End Engineering and Design
FID	Final Investment Decision
GJ	gigajoule
Mcf	thousand cubic feet
Mcf/d	thousand cubic standard feet per day
MI	monthly index
MMcf/d	million cubic feet per day
MMBtu	one million British Thermal Units is a measure of the energy content in gas
MMBtu/d	one million British thermal units per day
MW	one million watts
NGCC	Natural Gas Combined Cycle
NGLs	natural gas liquids, which includes butane, propane, and ethane
US$/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.

This MD&A includes references to sales volumes of "Oils and condensate", "NGLs" and "Natural gas" and revenues therefrom. National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities, includes condensate within the NGLs product type. The Company has disclosed condensate as combined with crude oil and separately from other NGLs since the price of condensate as compared to other NGLs is currently significantly higher, and the Company believes that this crude oil and condensate presentation provides a more accurate description of its operations and results therefrom. Crude oil therefore refers to light oil, medium oil, tight oil, and condensate. NGLs refers to ethane, propane, butane, and pentane combined. Natural gas refers to conventional natural gas and shale gas combined.

CORPORATE INFORMATION

Management

Pat Carlson
Chief Executive Officer

Jakub Brogowski
Chief Financial Officer

Mike Backus
Chief Operating Officer, Upstream

Janet Annesley
Chief Sustainability Officer

Fareen Sunderji
President, Power

Sue Kuethe
Executive VP, Land and Community Inclusion

Mike Hantzsch
Senior Vice President, Midstream and Market Development

Lisa Wong
Senior Vice President, Business Systems

Chris Lina
Vice President, Projects

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Bankers

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

Auditor

Deloitte LLP
Calgary, AB

Board of Directors

Kevin Brown
Board Chair

Beth Reimer-Heck
Lead Director

Judith Athaide
Director

Pat Carlson
Director and Chief Executive Officer

Leland Corbett
Director

Colin Bergman
Director

Kaush Rakhit
Director

Steve Sinclair
Director

John Whelen
Director

Reserve Engineers

McDaniel & Associates Consultants Ltd.
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Legal Counsel

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Norton Rose Fulbright Canada LLP
Calgary, AB

Transfer Agent

Computershare
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Stock Symbol

KEC
Toronto Stock Exchange