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 months ended March 31, 2024. 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 months ended March 31, 2024 (the "Financial Statements") and the audited financial statements as at and for the year ended December 31, 2023. Additional information is available on Kiwetinohk's website at www.kiwetinohk.com and on the Company's profile on 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 May 7, 2024.

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 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 owned infrastructure for processing the majority of the Company's production. 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 profitable future downstream markets for the Company's natural gas production, allowing it to capture a larger portion of the energy value chain.

Financial and operating highlights

	Q1 2024	Q1 2023
Production		
Oil & condensate (bbl/d)	**8,452**	7,558
NGLs (bbl/d)	**4,027**	2,517
Natural gas (Mcf/d)	**90,459**	83,526
Total (boe/d)	**27,556**	23,996
Oil and condensate % of production	**31%**	31%
NGL % of production	**15%**	10%
Natural gas % of production	**54%**	59%
Realized prices		
Oil & condensate ($/bbl)	**92.33**	100.25
NGLs ($/bbl)	**46.65**	65.55
Natural gas ($/Mcf)	**3.83**	4.84
Total ($/boe)	**47.72**	55.30
Royalty expense ($/boe)	**(3.62)**	(5.89)
Operating expenses ($/boe)	**(7.03)**	(7.66)
Transportation expenses ($/boe)	**(4.60)**	(5.35)
Operating netback [1] ($/boe)	**32.47**	36.40
Realized gain on risk management ($/boe) [2]	**0.80**	0.41
Realized gain on risk management - purchases ($/boe) [2]	**0.45**	1.98
Net commodity sales from purchases (loss) ($/boe) [1]	**0.20**	(0.05)
Adjusted operating netback [1]	**33.92**	38.74
Financial results ($000s, except per share amounts)		
Commodity sales from production	**119,662**	119,421
Net commodity sales from purchases (loss) [1]	**510**	(110)
Cash flow from operating activities	**75,183**	80,160
Adjusted funds flow from operations [1]	**75,024**	75,981
Per share basic	**1.72**	1.72
Per share diluted	**1.71**	1.70
Net debt to annualized adjusted funds flow from operations [1]	**0.79**	0.52
Free funds flow deficiency from operations (excluding acquisitions/dispositions) [1]	**(765)**	(32,648)
Net income	**11,092**	53,949
Per share basic	**0.25**	1.22
Per share diluted	**0.25**	1.21
Capital expenditures prior to dispositions [1]	**75,789**	108,629
Net dispositions [1]	**(21)**	(781)
Capital expenditures and net dispositions [1]	**75,768**	107,848

	March 31, 2024	December 31, 2023
Balance sheet ($000s, except share amounts)		
Total assets	**1,102,040**	984,214
Long-term liabilities	**300,684**	234,853
Net debt [1]	**189,916**	157,540
Adjusted working capital (deficit) surplus [1]	**(5,667)**	(17,808)
Weighted average shares outstanding		
Basic	**43,662,644**	44,218,711
Diluted	**43,878,950**	44,748,871
Shares outstanding end of period	**43,662,644**	44,184,985

1 – Non-GAAP and other financial measures that do 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 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

Given strong first quarter results and taking into account the anticipated impact of the Company's hedging program, Kiwetinohk has made the following updates to its 2024 guidance:

- **Production** is ahead of expectations as a result of strong new well production and an efficient capital program which resulted in wells being brought on stream earlier than planned. As a result, the Company has raised its full year production guidance to a range of 25.0 - 27.5 Mboe/d.

- **Royalties** are expected to decrease in response to lower benchmark natural gas pricing and increases in the proportion of production benefiting from Alberta royalty incentive programs. Accordingly, Kiwetinohk lowered its full year royalty rate guidance to 7% - 10% of revenue.

- **Operating costs** per boe benefited from increases in production and efficiencies realized at owned and operated infrastructure within the Simonette play as Kiwetinohk took advantage of unused infrastructure capacity. As a result, projected operating costs for the full year are reduced to $7.75 - $8.25/boe.

- **Transportation** costs benefited from a positive adjustment to 2023 expenses that was received in the first quarter of 2024. The adjustment reconciled previously paid pipeline obligations to match the actual volumes of goods shipped in 2023 and resulted in a reduction to 2024 transportation expenses. Accordingly, expected transportation costs for the full year are reduced to $5.75 - $6.25/boe.

- **Capital expenditures** are still expected to fall in a range between $275 - $295 million. Kiwetinohk maintains the flexibility to accelerate capital in the second half of 2024 if market conditions warrant.

- **Adjusted funds flow from operations** and the ratio of net debt to adjusted funds flow from operations are now updated to reflect strong first quarter results offset by a weaker commodity price outlook for the rest of the year. Taking into account actual results to date:

    - at US$70/bbl crude oil prices and US$2.00/MMBtu HH natural gas prices for the remainder of the year, full year adjusted funds flow from operations is now expected to fall within a range of $260 - $280 million
    - at US$80/bbl crude oil prices and US$3.00MMBtu HH natural gas prices for the remainder of the year, full year adjusted funds flow from operations is now expected to fall within a range of $290 - $315 million.

    At currently projected levels of capital expenditure, these revised guidance ranges would result in an expected ratio of net debt to adjusted funds flow from operations in a range from 0.5x to 0.8x exiting 2024.

Kiwetinohk's revised 2024 guidance discussed above and summarized below provides information relevant to expectations for financial and operational results. This corporate guidance is based on various commodity price scenarios, regulatory assumptions and economic conditions and readers are cautioned that certain guidance estimates may fluctuate. The Company has retained the flexibility to accelerate three additional Duvernay wells with an investment decision anticipated later in the second quarter of 2024. Kiwetinohk will update guidance if and as required throughout the year.

2024 Financial & Operational Guidance		Revised May 7, 2024	Previous March 5, 2024
Production (2024 average) [1]	Mboe/d	25.0 - 27.5	24.0 - 27.0
Oil & liquids	%	45% - 49%	45% - 49%
Natural gas [1]	%	51% - 55%	55% - 51%

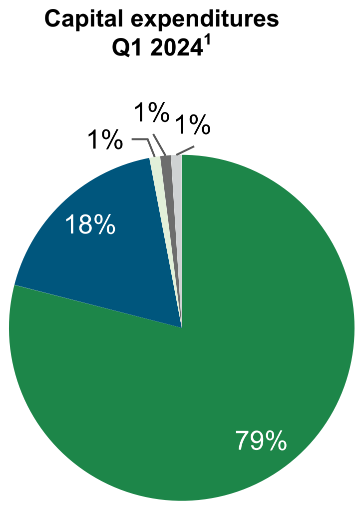
2024 Financial & Operational Guidance		Revised May 7, 2024	Previous March 5, 2024
Financial			
Royalty rate	%	7% - 10%	9% - 11%
Operating costs	$/boe	$7.75 - $8.25	$8.00 - $8.75
Transportation	$/boe	$5.75 - $6.25	$6.00 - $6.50
Corporate G&A expense [2]	$MM	$23 - $25	$23 - $25
Cash taxes[3]	$MM	$—	$—
Capital guidance	$MM	$275 - $295	$275 - $295
Upstream	$MM	$270 - $287	$270 - $287
DCET	$MM	$250 - $265	$250 - $265
Infrastructure, production maintenance and other	$MM	$20 - $22	$20 - $22
Power	$MM	$5 - $8	$5 - $8
2024 Adjusted Funds Flow from Operations commodity pricing sensitivities [4, 5]			
US$70/bbl WTI & US$2.00/MMBtu HH	CAD$MM	$260 - $280	$260 - $290
US$80/bbl WTI & US$3.00/MMBtu HH	CAD$MM	$290 - $315	$305 - $340
US$ WTI +/- $1.00/bbl [6]	CAD$MM	+/- $2.6	+/- $3.5
US$ Chicago +/- $0.10/MMBtu [6]	CAD$MM	+/- $1.0	+/- $1.4
CAD$ AECO 5A +/- $0.10/GJ [6]	CAD$MM	+/- $0.9	+/- $0.9
Exchange Rate (CAD$/US$) +/- $0.01 [6]	CAD$MM	+/- $2.4	+/- $3.1
2024 Net debt to Adjusted Funds Flow from Operations sensitivities [4, 5]			
US$70/bbl WTI & US$2.00/MMBtu HH	X	0.7x - 0.8x	0.7x - 0.8x
US$80/bbl WTI & US$3.00/MMBtu HH	X	0.5x - 0.6x	0.4x - 0.5x

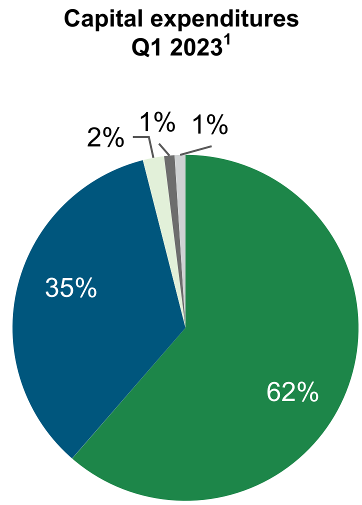
1 – Chicago sales of ~90% expected for 2024.
2 – Includes G&A expenses for all divisions of the Company – corporate, upstream, power and business development.
3 – The Company expects to pay United States cash taxes of approximately $0.3 million reflecting taxes payable by its US subsidiary during 2024. No Canadian cash taxes are anticipated in 2024..
4 – Non-GAAP and other financial measures that do 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.
5 – Based on actual realized pricing to date and flat forecast pricing for the remainder of the year.
6 – Assumes US$75/bbl WTI, US$2.50/mmbtu HH, US$0.80/mmbtu HH - AECO basis diff, $0.74 USD/CAD.

Capital expenditures

$000s	Q1 2024	Q1 2023
Drilling, completions, and equipping	**59,827**	66,812
Facilities, pipelines, roads and optimization	**13,610**	37,686
Power projects	**960**	2,023
Land and other	**455**	900
Capitalized G&A - upstream	**702**	996
Capitalized G&A - power	**235**	212
Capital expenditures [1]	**75,789**	108,629
Upstream net dispositions [1]	**(21)**	(781)
Capital and net dispositions [1]	**75,768**	107,848

1 – Non-GAAP and other financial measures that do 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.





1 – Capital expenditures shown are before acquisitions and 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 months ended March 31, 2024, the Company spent $59.8 million on its development program with a focus on the Simonette Duvernay lands. The Company completed and tied in a three well Duvernay pad ahead of schedule and finished drilling on another two well pad, which comprised one Duvernay and one Montney well, with completions expected to occur on these two wells in the third quarter of 2024. In addition, the Company commenced a two rig drilling program on two Duvernay pads (3 wells each) within the Tony Creek area with drilling expected to conclude in the second quarter of 2024.

The Company remains focused on further development of its core Simonette Duvernay lands with a smaller portion of its development capital allocated to delineation and optimization of the well design on the Company's Montney acreage.

Facilities, pipelines, roads and optimization

For the three months ended March 31, 2024, the Company spent $13.6 million on facilities, pipelines, roads and production optimization. Kiwetinohk's 2023 capital program included a significant investment in facilities and other infrastructure required to support growth and continue development within the basin. The 2024 program benefits from this upfront investment and requires less infrastructure spending, with a focus on infrastructure required to manage base production and develop and expand pipelines that are required to bring production from the 2024 development program on-stream.

Power development projects

The Company's power development portfolio includes four gas-fired and three solar projects with a total estimated nameplate capacity of approximately 2,150 MW. During the three months ended March 31, 2024, the Company moderated its development expenditures across the entire portfolio to $1.2 million, as participants in the Alberta power industry await policy clarity from both provincial and federal governments. Development activity is currently focused on preserving longer dated project positions in the Alberta Electric Systems Operator ("AESO") review process while advancing the Homestead Solar project and Opal Firm Renewable (gas-fired peaking) project toward a Final Investment Decision ("FID").

The majority of power capital expenditures in the first quarter of 2024 were directed to the Homestead Solar and Opal Firm Renewable projects, which remain the Company's most advanced development projects having achieved Stage 4 and 5 of their respective regulatory approval processes. During the first quarter, transmission approval was received from the the Alberta Utilities Commission ("AUC") for the Opal project, making it the Company's first fully permitted and licensed project. Transmission line approval remains the final key regulatory hurdle for the Homestead solar project. Kiwetinohk is seeking external non-dilutive capital to finance its power projects and has engaged a financial advisor to help identify potential financing partners and/or acquirers of the Homestead and/or Opal projects. Funding options for these projects include a partial or outright sale with proceeds helping to fund ongoing development of the remaining portfolio.

The Company is currently evaluating the regulatory environment and total estimated capital cost of the 101MW Opal project prior to any FID decision. The Company plans to make this decision after seeking and evaluating estimates on total installed costs and obtaining further clarity on the regulatory and operating environment for gas-fired peaking projects. Upon receiving confirmation of advancing to Stage 5 of the AESO regulator process, the Company paid a $1.0 million refundable deposit to the AESO for the Generating Unit Owner's Contribution ("GUOC") payment that was previously secured by a letter of credit. This payment has been recognized as part of prepaid expenses and deposits on the Condensed Consolidated Interim Balance Sheet and has not been recognized as a project development capital expenditure. This payment is expected to be refunded over a prescribed period upon achieving in-service status and satisfaction of specified performance criteria and any amounts not expected to be refunded would be expensed at such time.

The Company continues to review the status and potential impact of the final form of the Federal Government's Draft Clean Electricity Regulation ("CER") and the Alberta Government's proposal for a Restructured Energy Market ("REM") and interim measures that were announced at the end of the first quarter. The Company is currently evaluating the impact that these newly announced policy changes will have on its development portfolio and associated costs and timelines.

Early-stage development and design factors and the status of each of the Company's current power generation development projects as at May 7, 2024 are summarized in the following table:

<table>
<tr><th>Early-stage power development, design factors & status</th><th>Homestead (Solar 1)</th><th>Opal (Firm Renewable 1) [1]</th><th>Granum (Solar 2)</th><th>Phoenix (Solar 3)</th><th>Black Bear (NGCC 2)</th><th>Flipi (NGCC 1)</th><th>Little Flipi (Firm Renewable 2) [1]</th></tr>
<tr><td>Approximate Capacity (nameplate, AC)</td><td>400 MW</td><td>101 MW</td><td>350 MW</td><td>170 MW</td><td>500 MW</td><td>500 MW</td><td>124 MW</td></tr>
<tr><td>Approximate Capacity (net to grid, AC)</td><td>400 MW</td><td>97 MW</td><td>350 MW</td><td>170 MW</td><td>466 MW [8]</td><td>466 MW [8]</td><td>120 MW</td></tr>
<tr><td>Capacity factor</td><td>26% [5]</td><td>20% [6]</td><td>26% [5]</td><td>26% [5]</td><td>90%</td><td>90%</td><td>20% [6]</td></tr>
<tr><td>Heat rate [7] (MJ/KWH: +/-5%)</td><td>—</td><td>7.6</td><td>—</td><td>—</td><td>6.0</td><td>6.0</td><td>Under Evaluation</td></tr>
<tr><td>AESO stage</td><td>4</td><td>5</td><td>3</td><td>3</td><td>3</td><td>3</td><td>3</td></tr>
<tr><td>Earliest FID date</td><td>H2 2024</td><td colspan="6" rowspan="3">Kiwetinohk is currently limiting its investment in the project to the minimum required to maintain viability and regulatory positioning until further clarity is provided on the regulatory and policy revisions at both the federal and provincial levels. Once clarity is received, the Company will provide further project updates. Accordingly, the estimates of such dates and costs which had been previously provided by Kiwetinohk were withdrawn.</td></tr>
<tr><td>Earliest COD date [4]</td><td>H2 2026</td></tr>
<tr><td>Total estimated installed approximate capital cost ($ million) [2, 3]</td><td>$675 (Class 2)</td></tr>
</table>

1. The term "Firm Renewable" is a Kiwetinohk-originated term that describes efficient, flexible-output, fast-responding, gas-fired, reciprocating engine power generation. These facilities are also referred to as "gas-fired peakers" in the power industry.
2. Total installed approximate cost estimates are classified in a manner consistent with American Association of Cost Engineering (“AACE”) standards and excludes costs to finance projects. Class 2 estimates have an expected accuracy range of -15% to +20%.
3. None of the Company’s planned power generation projects have a final design, performance projection or cost estimate, or internal or external funding. With the exception of Opal, none of the projects have received full regulatory approval. 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 the estimated Commercial Operations Date (“COD”).
5. First year capacity factor based on DC/AC ratio of 1.39, and a bifacial, single axis solar panel tracking design.
6. Designed for intermittent operation. The actual dispatch will be based on market conditions and contract provisions.
7. 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.
8. Based on current regulations, power providers are restricted to generating a maximum of 466 MW on a single line.

Carbon storage hubs

The Company continued to evaluate its two proposed carbon storage hubs during the first quarter of 2024. Kiwetinohk believes it will be well positioned as a primary user of its provincially awarded carbon hubs through its associated power projects, Opal and Black Bear, which are in the early stages of development and through potential future CCS projects it may develop for its own use and the use of third parties.

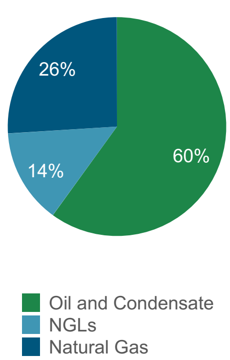
Results of operations

Production

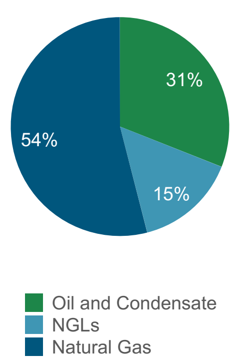
	Q1 2024	Q1 2023
Oil & condensate (bbl/d)	**8,452**	7,558
NGLs (bbl/d) [1]	**4,027**	2,517
Natural gas (Mcf/d)	**90,459**	83,526
Total production (boe/d)	**27,556**	23,996
Oil and condensate % of production	**31%**	31%
NGL % of production	**15%**	10%
Natural gas % of production	**54%**	59%
Total production volumes %	**100%**	100%

1 - NGL production includes production volumes for ethane (C2), propane (C3), butane (C4) and pentane (C5).

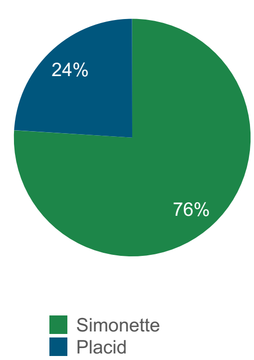
Revenue Mix ($)
Q1 2024



Production Mix (boe)
Q1 2024



Production by Area (boe)
Q1 2024



The Company achieved record quarterly production during the first quarter of 2024 averaging 27,556 boe/d compared to 23,996 boe/d in the first quarter of 2023. The increase in the Company's production volumes is attributable to the ongoing capital development program, which resulted in production from thirteen new wells placed into production since the first quarter of 2023, including the three well Duvernay pad that was brought on stream ahead of schedule during the first quarter of 2024.

The Company's production portfolio during the first quarter of 2024 was 31% oil and condensate, 15% NGLs and 54% natural gas, with the production profile becoming more liquids rich as compared to the first quarter of 2023. This change in composition was a result of the contribution of new wells brought on stream and as a result of a marketing decision in the fourth quarter of 2023 to operate the Company's processing facilities at a colder temperature to extract NGLs for sale to the Alberta market.

Benchmark and realized prices

	Q1 2024	Q1 2023
Liquid benchmark prices		
WTI (US$/bbl)	**76.96**	76.13
WTI (CDN$/bbl)	**103.82**	102.90
Edmonton Light (CDN$/bbl)	**92.14**	99.01
Natural gas benchmark prices		
Henry Hub (US$/MMBtu)	**2.25**	3.42
Chicago City Gate MI (US$/MMBtu)	**2.49**	4.32
Chicago City Gate DI (US$/MMBtu)	**2.82**	2.64
AECO 5A (CDN$/GJ)	**2.36**	3.05
AECO 7A (CDN$/GJ)	**1.94**	4.12
Foreign exchange rates (CAD/USD)	**0.74**	0.74

	Q1 2024	Q1 2023
Realized prices (before impact of hedging program)		
Oil & condensate ($/bbl)	**92.33**	100.25
NGLs ($/bbl)	**46.65**	65.55
Natural gas ($/Mcf)	**3.83**	4.84
Total ($/boe)	**47.72**	55.30

While crude oil prices have been subject to significant volatility over the past year, average prices for the three months ended March 31, 2024 were consistent with the comparative period in 2023, averaging US$76.96 and US$76.13 per barrel, respectively. However, Edmonton Light benchmark pricing experienced a decrease of approximately 7% when compared to the prior year period due to increased supply and a lack of available egress out of the Western Canadian Sedimentary basin.

NGL contracts are negotiated annually in April each year, with pricing in the first quarter of 2024 declining as compared to the first quarter of 2023 as a result of declines in contracted pricing. In addition, as a result of the Company's decision to sell additional volumes within the Alberta market in the fourth quarter of 2023, the Company sold those volumes into the lower priced spot markets ahead revised NGL contract terms in April 2024.

Henry Hub natural gas prices decreased to US $2.25 in the three months ended March 31, 2024, compared to US $3.42 in the first quarter of 2023. Declines were due to a relatively mild winter and increased North American supply. The Chicago City Gate monthly index benchmark for natural gas also decreased in the three months ended March 31, 2024 compared to the prior period for similar reasons. The Chicago City Gate monthly benchmark averaged US $2.49 per MMBtu compared to US $4.32 per MMBtu in 2023.

Natural gas prices at AECO in Alberta also decreased as new supply outpaced demand in the basin. On average, AECO 7A spot prices decreased to $1.94/GJ during the three months ended March 31, 2024 when compared to $4.12/GJ in the same period in 2023.

Operating netback

	Q1 2024	Q1 2023
Realized price ($/boe)	**47.72**	55.30
Royalty expenses ($/boe)	**(3.62)**	(5.89)
Operating expenses ($/boe)	**(7.03)**	(7.66)
Transportation expenses ($/boe)	**(4.60)**	(5.35)
Operating netback ($/boe) [1]	**32.47**	36.40
Realized gain on risk management ($/boe) [2]	**0.80**	0.41
Realized gain on risk management - purchases ($/boe) [2]	**0.45**	1.98
Net commodity sales from purchases (loss) ($/boe) [1]	**0.20**	(0.05)
Adjusted operating netback [1]	**33.92**	38.74
Total production (boe/d)	**27,556**	23,996

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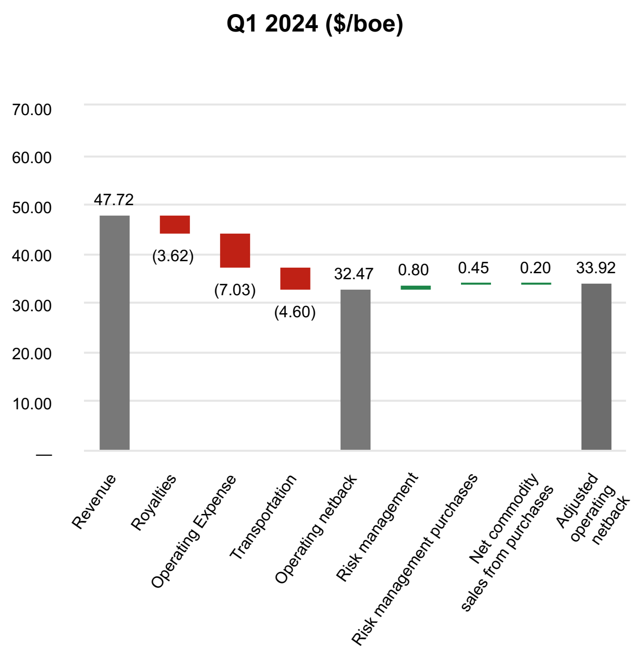

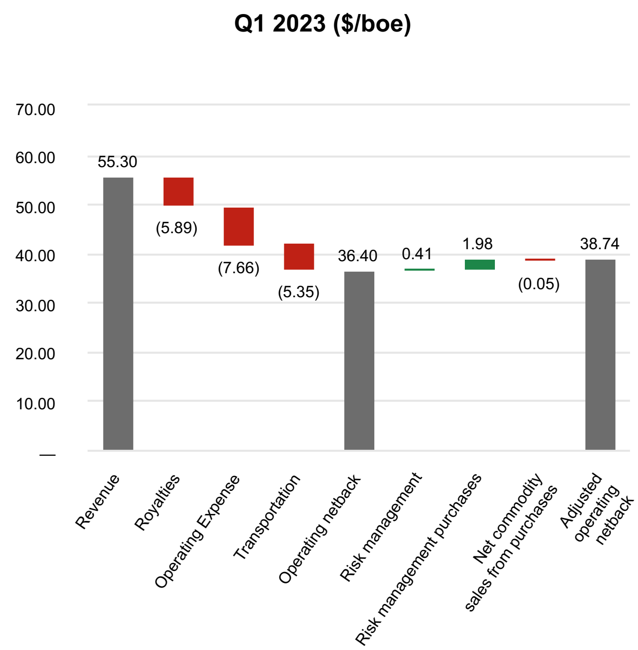

Operating netback during the three months ended March 31, 2024 was $32.47/boe compared to $36.40/boe in the comparative period in 2023. The decrease was driven by a $7.58/boe decline in average realized pricing relative to 2023, partially offset by cost savings realized within the quarter. During the three months ended March 31, 2024, per barrel royalties declined as a result of lower realized pricing and a larger proportion of the Company's production coming from new wells that are producing under royalty incentive programs. Operating costs per barrel improved largely as a result of higher production volumes and transportation costs per barrel declined as a result of a prior period adjustment which offset pipeline toll increases and increases in trucking charges resulting from changing production composition.

Adjusted operating netback was $33.92/boe for the quarter ended March 31, 2024. The Company realized gains on risk management contracts of $1.25/boe for the quarter, which partially offset decreases in realized pricing given a portion of produced and purchased volumes were hedged in accordance with Company policy to manage price volatility and ensure more predictable cash flows during a period of significant capital expenditures and growth.

Commodity sales from production

$000s	Q1 2024	Q1 2023
Oil & condensate	**71,019**	68,194
NGLs	**17,097**	14,849
Natural gas	**31,546**	36,378
Total commodity sales from production	**119,662**	119,421

The Company realized $119.7 million in revenues from production during the three months ended March 31, 2024, which was consistent with the comparative period in 2023. The Company grew production by approximately 15% when compared to the prior year period, however growth in production was offset by a 14% decrease in realized pricing when compared to the prior year period.

Net commodity sales from purchases

$000s	Q1 2024	Q1 2023
Commodity sales from purchases	**15,983**	20,498
Commodity purchases, transportation and other	**(15,473)**	(20,608)
Net commodity sales from purchases (loss) [1]	**510**	(110)
Realized hedging gain on purchases	**1,117**	4,279
Net commodity sales from purchases after hedging[1]	**1,627**	4,169
$/boe – before hedging	**0.20**	(0.05)
$/boe – after hedging	**0.65**	1.93

1 – Non-GAAP and other financial measures that do 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. The Company was able to successfully purchase and fill the balance of its Alliance firm transportation commitment during the three months ended March 31, 2024, not met through proprietary field production and temporarily assigned volumes.

As part of its broader risk management program, the Company 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 utilize 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.

In the three months ended March 31, 2024, the Company realized a gain of $0.5 million on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system. Including the impact of associated risk management contracts, the Company realized overall marketing income of $1.6 million for the three months ended March 31, 2024, relative to $4.2 million for the same period in 2023.

Risk management contracts

In an effort to mitigate commodity price fluctuations for natural gas, crude oil and NGLs, 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 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 also regularly reviews its credit exposure to the counterparties that it enters into risk management contracts with.

$000s	Q1 2024	Q1 2023
Risk management:		
Unrealized (loss) gain	**(15,140)**	28,811
Realized gain	**3,135**	5,169
Total (loss) gain on risk management	**(12,005)**	33,980
Unrealized (loss) gain ($/boe)	**(6.04)**	13.34
Realized gain ($/boe)	**1.25**	2.39

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

$000s	Q1 2024	Q1 2023
Realized gain on production	**2,672**	1,973
Realized gain on purchases	**1,117**	4,279
Realized loss on foreign exchange	**(654)**	(1,083)
Total realized gain	**3,135**	5,169
Realized gain on production ($/boe)	**1.06**	0.91
Realized gain on purchases ($/boe)	**0.45**	1.98
Realized loss on foreign exchange ($/boe)	**(0.26)**	(0.50)

For the three months ended March 31, 2024, the Company recorded realized gains on risk management contracts of $3.1 million. Approximately 36% of the gains for the quarter was related to natural gas volumes purchased for resale required to meet pipeline commitments in excess of the Company's production needs, where the Company hedges price differences between Chicago and Alberta markets at the time of contracting third party natural gas purchases.

Gains were realized on production hedges in the three months ended March 31, 2024 and 2023. Hedge contract prices were generally higher than relevant benchmark prices at the time of settlement in each respective period resulting in gains being realized. When compared to the first quarter of 2023, gains related to volumes purchased to fill pipeline capacity declined as a result of the differential between Chicago and AECO prices relative to hedged rates widening (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 and crude oil financial contracts on the balance sheet at each reporting period with the change in the fair value being classified as unrealized gains and losses in the condensed consolidated interim statement of net income and comprehensive 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 $15.1 million during the first quarter of 2024 represents the change in the fair value of risk management contracts during that period. As of March 31, 2024 the Company's hedging portfolio was a $4.4 million asset (net receivable) as compared to an asset of $19.5 million as at December 31, 2023.

The Company has the following commodity risk management contracts outstanding as of March 31, 2024:

Type		Q2 2024	Q3 2024	Q4 2024	2025	2026	2027
Crude oil [1]							
WTI swap	bbl/d	1,750	1,750	2,000	563	—	—
WTI buy put	bbl/d	4,367	3,833	3,000	1,833	—	—
WTI sell call	bbl/d	3,500	3,333	2,500	1,833	—	—
WTI swap average	US$/bbl	$74.32	$74.32	$73.91	$74.17	$—	$—
WTI buy put average	US$/bbl	$67.75	$69.14	$69.17	$69.14	$—	$—
WTI sell call average	US$/bbl	$79.52	$79.32	$77.98	$78.16	$—	$—
Natural gas [1]							
NYMEX Henry Hub swap	MMBtu/d	3,333	2,500	2,500	—	—	—
NYMEX Henry Hub buy put	MMBtu/d	45,833	45,833	40,833	28,958	15,868	1,035
NYMEX Henry Hub sell call	MMBtu/d	37,500	35,833	32,500	28,958	15,868	1,035
NYMEX Henry Hub swap average	US$/MMBtu	$3.18	$3.23	$3.23	$—	$—	$—
NYMEX Henry Hub buy put average	US$/MMBtu	$3.14	$3.11	$3.19	$3.24	$3.14	$3.00
NYMEX Henry Hub sell call average	US$/MMBtu	$3.92	$3.96	$4.14	$4.60	$4.49	$3.90
Natural gas transportation [1,2]							
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	30,000	30,000	10,000	—	—	—
Sell GDD Chicago basis (to NYMEX Henry Hub) [3]	MMBtu/d	(30,000)	(30,000)	(10,000)	—	—	—
AECO 5A basis (to NYMEX Henry Hub) average	US$/MMBtu	$(1.28)	$(1.28)	$(1.28)	$—	$—	$—
GDD Chicago basis (to NYMEX Henry Hub) average [3]	US$/MMBtu	$(0.07)	$(0.07)	$(0.07)	$—	$—	$—

1 – Prices per unit and volumes per day are represented at the average amounts for the period.
2 – Natural gas transportation hedges relate to exposure to basis pricing differentials between AECO and Chicago arising from firm transportation commitments.
3 – 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 March 31, 2024:

Type		Q2 2024	Q3 2024	Q4 2024	2025	2026	2027
Foreign exchange							
Sell USD CAD (monthly average)	US$	$9.0 MM	$9.0 MM	$9.0 MM	$16.5 MM	$— MM	$— MM
USD CAD buy put	US$	$5.0 MM	$5.0 MM	$5.0 MM	$2.5 MM	$5.0 MM	$— MM
USD CAD sell call	US$	$5.0 MM	$5.0 MM	$5.0 MM	$2.5 MM	$5.0 MM	$— MM
USD CAD fixed sell rate		$1.33	$1.33	$1.33	$1.34	$—	$—
USD CAD put rate		$1.32	$1.32	$1.32	$1.33	$1.28	$—
USD CAD call rate		$1.34	$1.34	$1.34	$1.38	$1.35	$—

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 asset outstanding are as follows:

$000s	March 31, 2024	December 31, 2023
Short term risk management asset	**12,040**	10,708
Long term risk management asset	**175**	8,838
Short term risk management liability	**(6,758)**	—
Long term risk management liability	**(1,051)**	—
Total risk management contracts asset	**4,406**	19,546

$000s	March 31, 2024	December 31, 2023
Asset on produced volumes	**3,914**	9,186
Asset on purchased volumes	**5,595**	3,616
(Liability) asset on foreign exchange contracts	**(5,103)**	6,744
Total risk management contracts asset	**4,406**	19,546

Royalty expense

$000s	Q1 2024	Q1 2023
Royalty expense	**9,067**	12,718
As a % of revenue	**7.6 %**	10.6 %
$/boe	**3.62**	5.89

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties in the three months ended March 31, 2024 decreased to $9.1 million and 7.6% of revenue as compared to $12.7 million and 10.6% of revenue in the comparative period of 2023. Decreases in royalties resulted from declines in realized pricing and an increased proportion of production from new wells which benefit from provincial incentive programs. Alberta's drilling and completion cost allowance program 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.

Operating expenses

$000s	Q1 2024	Q1 2023
Operating expenses	**17,625**	16,542
$/boe	**7.03**	7.66

Operating costs include amounts incurred to extract commodities to the surface such as field operators, gas and liquids processing, gathering and compression, utilities, chemicals and maintenance related costs. Operating costs during the three months ended March 31, 2024, increased to $17.6 million, due to increased production volumes and higher levels of activity.

For the three months ended March 31, 2024, operating expenses per boe decreased by 8.2% to $7.03/boe relative to the same period in 2023 as higher production led to operating efficiencies gained through the Company's owned and operated infrastructure within Simonette.

Transportation expenses

$000s	Q1 2024	Q1 2023
Transportation expenses	**11,539**	11,548
$/boe	**4.60**	5.35

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.

Transportation expense for the three months ended March 31, 2024 was $11.5 million and was consistent with the respective 2023 period. On a per barrel basis, transportation expenses decreased by 14.0% to $4.60/boe over the same period as a result of a positive adjustment to 2023 expenses that was received in the first quarter of 2024. The adjustment reconciled previously paid pipeline obligations to match the actual volumes of goods shipped in 2023 and resulted in a reduction to 2024 transportation expenses. Excluding this credit, transportation expenses per barrel for the first quarter of 2024 would have increased by 3% over the first quarter of 2023 to $5.49/boe as a result of pipeline toll increases and increases in trucking charges resulting from changing production composition.

Adjusted funds flow from operations

$000s	Q1 2024	Q1 2023
Cash flows from operating activities	**75,183**	80,160
Net change in non-cash working capital from operating activities	**(704)**	(7,323)
Asset retirement obligation expenditures	**545**	3,144
Adjusted funds flow from operations [1]	**75,024**	75,981
$/boe	**29.92**	35.18

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 from operations decreased to $75.0 million and $29.92/boe for the three months ended March 31, 2024, relative to 76.0 million and $35.18/boe for the same period in 2023. The decline on a total basis was driven by the reduction in adjusted operating netback described above and increased financing costs resulting from higher average debt levels outstanding at higher interest rates. The decrease on a per barrel basis is attributable to these same factors, offset by a 15% increase in production over the same period.

Free funds flow from operations

$000s	Q1 2024	Q1 2023
Adjusted funds flow from operations [1]	**75,024**	75,981
Capital expenditures [1]	**(75,789)**	(108,629)
Free funds flow deficiency from operations [1]	**(765)**	(32,648)
$/boe	**(0.31)**	(15.12)

1 – Non-GAAP and other financial measures that do 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.

Free funds flow deficiency from operations during the three months ended March 31, 2024 was $0.8 million relative to a free funds flow deficiency of $32.6 million in the comparative period of 2023. The Company continues to execute a capital program aimed at generating short and longer-term production and cash-flow growth through development of its existing reserve base and investment in the infrastructure required to grow production in future periods.

The Company has been able to fund capital spending using cashflow from operations and available credit facilities and continuously monitors its liquidity position and financial performance to ensure ongoing financial flexibility and has the ability to adjust future capital spending plans if required to manage liquidity and/or balance sheet constraints.

General and administrative ("G&A") expenses

$000s	Q1 2024	Q1 2023
Gross G&A expenses	**7,027**	5,583
Less capitalized G&A	**(937)**	(1,208)
G&A Expenses	**6,090**	4,375
$/boe	**2.43**	2.03

Gross G&A expenses increased to $7.0 million during the three months ended March 31, 2024 as compared to $5.6 million in the same period in 2023. G&A expense per barrel was $2.43/boe and increased compared to $2.03/boe in the comparative prior year period as a result of continued growth in the Company's operations and development activity.

A portion of G&A expense continues to be directly related to business development initiatives in the power segment including the development of renewable and natural gas-fired power generation projects as well as early stage investigation of opportunities of carbon capture technology and hydrogen production.

Share-based compensation expenses

$000s	Q1 2024	Q1 2023
Equity-settled awards	**809**	956
Cash-settled awards	**1,270**	240
Total share-based compensation expenses	**2,079**	1,196
$/boe	**0.83**	0.55

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 $2.1 million for the three months ended March 31, 2024 compared to $1.2 million in the same period in 2023, with the increase attributable to more cash-settled awards outstanding and a higher share price at the end of the 2024 period.

Finance costs

$000s	Q1 2024	Q1 2023
Interest and bank charges	**4,662**	3,382
Accretion of asset retirement obligations	**859**	865
Interest on lease obligations	**537**	220
Deferred financing amortization	**161**	324
Unrealized gain on foreign exchange	**(554)**	(4)
Total finance costs	**5,665**	4,787
$/boe	**2.26**	2.22

The Company has a $375 million senior secured extendible revolving facility (the “Credit Facility”) with a syndicate of banks. As at March 31, 2024 the Company had drawn $185.0 million on the facility (March 31, 2023 - $139.9 million).

The increase in financing costs for the three months ended March 31, 2024 is associated with higher average debt levels outstanding and higher interest rates. The average outstanding debt for the three months ended March 31, 2024 was approximately $60 million higher than the comparative period in 2023 with average interest rates of approximately 8.35% in the first quarter of 2024 compared to 7.91% in the first quarter of 2023.

Depletion and Depreciation

$000s	Q1 2024	Q1 2023
Depletion	**41,711**	31,440
Depreciation	**515**	448
Total depletion and depreciation	**42,226**	31,888
$/boe	**16.84**	14.77

The Company recognized depletion of $41.7 million for the three months ended March 31, 2024 compared to $31.4 million in 2023, with the increase due to a higher depletion rate combined with a 15% increase in production over the same period.

Depletion per barrel for the three months ended March 31, 2024 increased compared to 2023, due to a greater depletable base resulting from the Company's continued development and an increase in year over year estimated future development costs assigned in accordance with the Company's 2023 reserve report. Increases in future development costs arose from inflationary pressures and the reallocation of capital to more liquids-rich development along with changes to other assumptions utilized by independent external reserve evaluators, offset by an increase in proved and probable reserves assigned.

Income taxes

As of March 31, 2024, the Company recognized a net deferred tax liability of $13.5 million. The Company’s estimated tax pools as at March 31, 2024, are as follows:

Category	Deductibility	$000s
Canadian oil and gas property expense (“COGPE”)	10%	182,841
Successored COGPE	10%	1,032
Canadian development expense (“CDE”)	30%	239,048
Successored CDE	30%	51,751
Undepreciated capital cost (“UCC”)	Primarily 25%, declining balance	177,672
Non-capital losses	100%	193,331
Share/Debt issue costs	5-year straight line	2,531
Total estimated tax pools		848,206

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 undiscounted, uninflated, future cash flows to settle its ARO is $111.9 million, or $176.4 million inflated at 1.84% and undiscounted. These cash flows have been discounted using a risk-free interest rate of 3.34% to arrive at the present value estimate of $80.8 million.

There is approximately $26.0 million (December 31, 2023: $26.7 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 significantly reduce 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)	2024	2023				2022		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Production (average boe/d)	**27,556**	24,707	21,218	20,432	23,996	24,745	16,487	16,810
Commodity sales from production	**119,662**	114,038	94,432	83,935	119,421	159,457	122,644	137,931
Commodity sales from purchases	**15,983**	18,136	19,464	17,475	20,498	47,902	77,623	82,429
Cash flow from operating activities	**75,183**	58,946	60,294	41,360	80,160	87,028	91,710	38,780
Per share (basic)	**1.72**	1.35	1.37	0.94	1.81	1.97	2.08	0.88
Per share (diluted)	**1.71**	1.33	1.36	0.93	1.79	1.94	2.05	0.87
Net income (loss)	**11,092**	48,302	(12,056)	21,701	53,949	115,308	55,379	44,854
Per share (basic)	**0.25**	1.11	(0.27)	0.49	1.22	2.61	1.26	1.02
Per share (diluted)	**0.25**	1.09	(0.27)	0.49	1.21	2.57	1.24	1.01

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. It relies on cash flow from operating activities, available funding capacity on its 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 Kiwetinohk's 2024 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 March 31, 2024, $185.0 million was outstanding on the Credit Facility before deferred financing costs (December 31, 2023 - $195.0 million) along with $86.3 million (December 31, 2023 - $89.4 million) in letters of credit issued to support transportation and other commitments. Of the $86.3 million letters of credit, $62.4 million were provided for through the EDC facility (see below), and the remaining $23.9 million were issued under the Credit Facility and reduce the available operating facility capacity.

$000s	Borrowing capacity	Drawn	Letters of credit	Available Capacity
Credit Facility	375,000	185,000	23,877	**166,123**
EDC Facility	75,000	—	62,396	**12,604**
Total				**178,727**

$000s	March 31, 2024	December 31, 2023
Credit facility drawn	**185,000**	195,000
Deferred financing costs	**(751)**	(912)
Loans and borrowings	**184,249**	194,088
Adjusted working capital deficit (surplus) [1]	**5,667**	(7,565)
Net debt [1]	**189,916**	186,523
Annualized adjusted funds flow from operations [1]	**240,354**	241,311
Net debt to annualized adjusted funds flow from operations [1]	**0.79**	0.77

1 – Non-GAAP and other financial measures that do 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 charged at the prevailing bankers' acceptance rate plus the applicable 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"). Applicable margins over the bank's prime rate or U.S. base rate range from 1.75 percent to 5.25 percent and stamping fees applicable to the relevant bankers' acceptance rate range 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 to fund working capital and planned capital expenditures in advance of cash flow from new investments while targeting to maintain a net debt to last-twelve-months of adjusted funds flow from operations ratio of no more than 1.0 times (March 31, 2024 - 0.79 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 letters of credit. 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. The Company expects to renew the PSG in May 2024 concurrently with its annual borrowing base review of the consolidated Credit Facility. At March 31, 2024, the Company has $12.6 million of capacity remaining under the LC Facility (December 31, 2023 - $8.9 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 Kiwetinohk continues to pursue potential acquisition opportunities. It 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.

The Company intends to file a renewal base shelf prospectus in the second quarter of 2024.

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 19, 2023, the Company renewed its normal course issuer bid ("NCIB"), allowing the Company to purchase and cancel up to 2.2 million Common Shares prior to December 22, 2024. The Company has not purchased shares under the NCIB program during the three months ended March 31, 2024.

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 2024 with the amount and timing of any purchases depending, among other things, on the share price, commodity prices and overall budget projections.

(000s)	Q1 2024	Q1 2023
Weighted average shares outstanding		
Basic	**43,663**	44,219
Diluted	**43,879**	44,749
Outstanding securities		
Common shares	**43,663**	44,185
Stock options[1]	**2,766**	2,601
Performance warrants[1]	**6,768**	7,095
Total diluted outstanding securities	**53,197**	53,881

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 May 7, 2024, the Company has 43,666,822 Common Shares and no preferred shares outstanding.

Commitments, contractual obligations, and contingencies

$ millions	2024	2025	2026	2027	2028	Thereafter
Accounts payable	61.9	—	—	—	—	—
Cash-settled compensation liability [1]	1.8	1.0	0.3	—	—	1.4
Loans and borrowings [2]	—	185.0	—	—	—	—
Gathering, processing and transport	57.3	67.2	14.8	16.2	16.2	21.8
Natural gas purchases	22.8	—	—	—	—	—
Upstream and corporate lease liabilities	1.5	2.2	2.2	2.2	2.2	6.3
Power lease liabilities[3]	2.0	1.3	1.3	1.3	1.3	25.9
Power construction	—	0.6	—	—	—	—
Other	—	0.4	0.4	0.4	0.4	0.4
Total	147.3	257.7	19.0	20.1	20.1	55.8

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 – Assumes current debt drawn is repaid at the current maturity date of the Credit Facility.
3 – The Company has not reached a final investment decision ("FID") on power projects as of the date hereof. 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 on the Nova Gas Transmission Ltd. and Alliance pipelines, with a commitment to deliver approximately 120.0 MMcf per day of gas to Chicago on Alliance through October 2025.

The Company currently has secured 37,100 GJ per day of gas supply (approximately 32.5 MMcf per day) from natural gas producers through October 2024, preparing 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.

The Company may be involved in litigation and disputes arising in the normal course of operations. Management is of the opinion that any potential litigation will not have a material adverse impact on the Company's financial position or results of operations as at March 31, 2024.

Related party information

For the three months ended March 31, 2024, the Company incurred a total of $0.3 million (March 31, 2023 – $0.2 million) in a related party transaction in which the Company retained a law firm to provide legal services on corporate matters. A director of the Company is a partner of this law 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 expects to publish its 2024 ESG report (for the 2023 reporting year) concurrently with this MD&A guided by the Sustainability Accounting Standards Board ("SASB") data standards for Oil & Gas – Exploration and Production and the Financial Stability Board's 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 months ended March 31, 2024. For additional information on risk factors, refer to the Company’s audited financial statements as at and for the year ended December 31, 2023 and the Company’s Annual Information Form (“AIF”) dated March 5, 2024 available 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 January 1, 2024, and ending on March 31, 2024, 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

Changes in accounting policies including initial adoption
There were no changes in accounting policies that had a material effect on the Company's financial statements during the three months ended March 31, 2024.

Critical accounting estimates

The significant accounting judgements and estimates used by the Company are discussed in the notes of the December 31, 2023 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 were no material changes to the Corporation's critical accounting estimates and judgments during the three months ended March 31, 2024.

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 cash, share based compensation liability, and risk management contracts. 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 expenditures 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 income and comprehensive 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 March 31, 2024.

Other

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	Q1 2024	Q1 2023
Commodity sales from production	**119,662**	119,421
Royalty expenses	**(9,067)**	(12,718)
Operating expenses	**(17,625)**	(16,542)
Transportation expenses	**(11,539)**	(11,548)
Operating netback	**81,431**	78,613
Realized gain on risk management	**2,018**	890
Realized gain on risk management - purchases	**1,117**	4,279
Net commodity sales from purchases (loss)	**510**	(110)
Adjusted operating netback	**85,076**	83,672

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, and refundable payments made under the AESO connection process. 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	Q1 2024	Q1 2023
Cash flow used in investing activities	**69,283**	102,101
Net change in non-cash investing working capital	**7,470**	15,747
Power connection process payment	**(985)**	—
Settlement of contingent consideration	**—**	(10,000)
Capital expenditures and net acquisitions (dispositions)	**75,768**	107,848
Proceeds from disposition	**21**	781
Net dispositions	**21**	781
Capital expenditures	**75,789**	108,629

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.

<u>Non-GAAP Financial Ratios</u>

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 as measured by boe. 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 per boe” is cash flow from operating activities before changes in net change in non-cash working capital from operating activities, asset retirement obligations, and transaction 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.

<u>Capital Management Measures</u>

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 transaction 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	March 31, 2024	December 31, 2023
Current assets	**78,868**	87,951
Current liabilities	**(79,253)**	(69,678)
Working capital (deficit) surplus	**(385)**	18,273
Short term risk management contracts net liability (asset)	**(5,282)**	(10,708)
Adjusted working capital (deficit) surplus	**(5,667)**	7,565

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 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 vision of incorporating carbon capture technology and hydrogen production to its portfolio, all as a part of a broader, integrated portfolio of clean energy assets;
- the Company's growth strategy, including identification and development of natural gas-fired power generation and renewable projects and the Company's plans for the power portfolio to create future profitable markets for the Company's natural gas production;
- expected greenfield and brownfield development opportunities;
- the Company's detailed 2024 financial and operational guidance and adjustments to the previously communicated 2024 guidance, including anticipated increase in production, reduction in royalties, reduction in operating costs and reduction in transportation costs, reduction in adjusted funds flow from operations and confirmation of expected future capital expnditures plans ;
- anticipated well production;
- 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 timing and amount of cash taxes for the Company's US subsidiary and the Company's expectations regarding being taxable in Canada and the timing thereof;
- expectations regarding the conclusion of drilling two Duvernay pads and the timing thereof;
- receipt of further clarity from provincial and federal governments regarding pending electricity regulations;
- successful execution of the Company's power projects and the impacts thereof;
- receipt of regulatory approvals for the Company's Homestead Solar project, and timing thereof, including AUC transmission line approval;
- submission of applications and receipt of certain regulatory approvals, for the broader power portfolio, and timing thereof;
- the expected structure of a financing arrangement for power projects, or the portfolio, including external capital and/or sale of projects;
- the anticipated outcomes of successful execution of the Company's investment and financing strategies for its power project portfolio;
- timing for the Company's Homestead Solar project to reach FID and COD, and the expected costs thereof;
- the Company's future investigations, 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;
- 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;
- asset retirement obligations and the estimated future cash flows to settle such obligations;
- the expectation of reducing the inactive asset retirement obligations over the next five to seven years through the creation of an abandonment program;
- operating and capital costs in 2024;
- sufficiency of funds to meet the Company's working capital requirements and anticipated drilling through 2024;
- timing for the next scheduled redetermination of the borrowing base on the Company's consolidated Credit Facility and EDC letter of credit facility;
- the Company's expectations regarding the renewal of its base shelf prospectus;
- 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 Company's expectations on timing and use of the NCIB program during 2024;
- the Company's expectations regarding the impact of future accounting pronouncements on the consolidated financial statements;
- expectations regarding the Company's ability to continue to manage risk through hedging contracts and risk management contracts;
- the Company's ability to continue to meet its pipeline transportation commitments;
- expectations regarding the future risk associated with take or pay pipeline obligations;
- the Company's ability to continue to benefit from Alberta's drilling and completion cost allowance program;

- the expected demand for, and prices and inventory levels of, petroleum products, including NGL;
- 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 expectation of ~90% of natural gas sales being directed to the Chicago market during 2024;
- 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 expectation of adding value through delineating the Duvernay and Montney assets and retaining core land;
- the impact of the Federal Government's draft CER and the REM
- 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 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 extend the PSG under the EDC LC Facility;
- 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 natural disaster, 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 natural disaster, war, hostilities, civil insurrection, pandemics (including COVID-19), instability and political and economic conditions (including the ongoing Russian-Ukrainian 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 regarding provincial and federal government electricity regulations and policies;
- 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 information concerning expectations for adjusted funds flow from operations and the ratio of 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
$/Mcf	dollars per thousand cubic feet
AECO	the daily average benchmark price for natural gas at the physical storage and trading hub for natural gas on the TransCanada Alberta transmission system which is the delivery point for various benchmark Alberta index prices
AESO	Alberta Electric Systems Operator
AIF	Annual Information Form
AUC	Alberta Utilities Commission
bbl/d	barrels per day
boe	barrel of oil equivalent, including crude oil, condensate, natural gas liquids, and natural gas (converted on the basis of one boe per six Mcf of natural gas)
boe/d	barrel of oil equivalent per day
CCS	Carbon Capture and Storage
CER	Clean Electricity Regulation
COD	Commercial Operations Date
DI	daily index
FEED	Front End Engineering and Design
FID	Final Investment Decision
GJ	gigajoule
Mcf	thousand cubic feet
Mcf/d	thousand cubic standard feet per day
MI	monthly index
MMcf/d	million cubic feet per day
MMBtu	one million British Thermal Units is a measure of the energy content in gas
MMBtu/d	one million British thermal units per day
MW	one million watts
NGCC	Natural Gas Combined Cycle
NGLs	natural gas liquids, which includes butane, propane, and ethane
REM	Restructured Energy Market
US$/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. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from an energy equivalency of 6:1, utilizing a conversion ratio of 6:1 may be misleading as an indication of value.

This MD&A includes references to sales volumes of "crude oil" "oil 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

Janet Annesley
Chief Sustainability Officer

Mike Backus
Chief Operating Officer, Upstream

Jakub Brogowski
Chief Financial Officer

Mike Hantzsch
Senior Vice President, Midstream and Market Development

Sue Kuethe
Executive VP, Land and Community Inclusion

Chris Lina
Senior Vice President, Projects

Craig Parsons
Vice President, Finance, Power Division

Fareen Sunderji
President, Power

Lisa Wong
Senior Vice President, Business Systems

Board of Directors

Kevin Brown
Board Chair

Beth Reimer-Heck
Lead Director

Judith Athaide
Director

Colin Bergman
Director

Pat Carlson
Director and Chief Executive Officer

Leland Corbett
Director

Kaush Rakhit
Director

Steve Sinclair
Director

John Whelen
Director

Corporate Head Office

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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

Reserve Engineers

McDaniel & Associates Consultants Ltd.
Calgary, AB

Legal Counsel

Stikeman Elliot LLP
Norton Rose Fulbright Canada LLP
Calgary, AB

Transfer Agent

Computershare
Calgary, AB

Stock Symbol

KEC
Toronto Stock Exchange