

Management's discussion and analysis

The following is Management's Discussion and Analysis ("MD&A") of the financial performance and results of operations for Kiwetinohk Energy Corp. ("Kiwetinohk" or the "Company") as at and for the three and six months ended June 30, 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 and six months ended June 30, 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 July 30, 2024.

Overview of business

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 in significant Duvernay and Montney resources with development upside and owned infrastructure for processing the majority of the Company's production.

Power

The power business unit is pursuing development of an Alberta-based power generation project portfolio that currently includes solar, and natural gas-fired power and carbon capture and storage ("CCS") facilities for use in its own operations and by third parties. Successful development of Kiwetinohk's power projects would enable the production of reliable, dispatchable, affordable energy with lower emissions intensity relative to energy generated through Alberta's grid today.

Financial and operating highlights

	For the three months ended		For the six months ended	
	2024	June 30, 2023	2024	June 30, 2023
Production				
Oil & condensate (bbl/d)	7,598	6,398	8,025	6,975
NGLs (bbl/d)	3,817	2,275	3,922	2,395
Natural gas (Mcf/d)	89,259	70,552	89,859	77,003
Total (boe/d)	26,292	20,432	26,924	22,204
Oil and condensate % of production	29%	31%	30%	31%
NGL % of production	15%	11%	15%	11%
Natural gas % of production	56%	58%	55%	58%
Realized prices				
Oil & condensate (\$/bbl)	102.71	91.48	97.25	96.21
NGLs (\$/bbl)	42.21	47.94	44.49	57.14
Natural gas (\$/Mcf)	2.39	3.23	3.11	4.10
Total (\$/boe)	43.91	45.14	45.86	50.60
Royalty expense (\$/boe)	(3.96)	(5.29)	(3.78)	(5.61)
Operating expenses (\$/boe)	(6.17)	(8.82)	(6.61)	(8.19)
Transportation expenses (\$/boe)	(5.97)	(6.06)	(5.27)	(5.68)
Operating netback ¹ (\$/boe)	27.81	24.97	30.20	31.12
Realized gain on risk management (\$/boe) ²	0.70	4.58	0.76	2.34
Realized gain on risk management - purchases (\$/boe) ²	0.79	2.06	0.61	2.02
Net commodity sales from purchases (loss) (\$/boe) ¹	0.03	(1.61)	0.12	(0.77)
Adjusted operating netback (\$/boe) ¹	29.33	30.00	31.69	34.71
Financial results (\$000s, except per share amounts)				
Commodity sales from production	105,049	83,935	224,711	203,356
Net commodity sales from purchases (loss) ¹	87	(3,004)	597	(3,114)
Cash flow from operating activities	61,232	41,360	136,415	121,520
Adjusted funds flow from operations ¹	60,637	46,319	135,661	122,300
Per share basic	1.39	1.05	3.11	2.77
Per share diluted	1.37	1.04	3.08	2.74
Net debt to annualized adjusted funds flow from operations ¹	0.81	0.64	0.81	0.64
Free funds flow deficiency from operations (excluding acquisitions/dispositions) ¹	(9,802)	(12,486)	(10,567)	(45,134)
Net (loss) income	(26,538)	21,701	(15,446)	75,650
Per share basic	(0.61)	0.49	(0.35)	1.71
Per share diluted	(0.61)	0.49	(0.35)	1.70
Capital expenditures prior to acquisitions (dispositions) ¹	70,439	58,805	146,228	167,434
Net acquisitions (dispositions) ¹	—	431	(21)	(350)
Capital expenditures and net acquisitions (dispositions) ¹	70,439	59,236	146,207	167,084
			June 30, 2024	December 31, 2023
Balance sheet (\$000s, except share amounts)				
Total assets			1,083,142	1,085,615
Long-term liabilities			304,233	305,735
Net debt ¹			206,626	186,523
Adjusted working capital (deficit) surplus ¹			(17,447)	7,565
Weighted average shares outstanding				
Basic			43,666,592	43,971,108
Diluted			44,148,950	44,467,348
Shares outstanding end of period			43,668,489	43,662,644

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

Kiwetinohk made the following updates to its full year 2024 guidance last provided on May 27, 2024:

- **Increased the lower end of full-year production guidance** from 25.0 - 27.5Mboe/d to a revised range of 26.0 - 27.5Mboe/d.
- **Reduced full-year operating cost projections** from \$7.75 - \$8.25/boe to \$7.25 - \$7.75/boe.
- **Reduced full-year transportation cost projections** from \$5.75 - \$6.25/boe to \$5.50 - \$6.00/boe.

Kiwetinohk also revised sensitivities for its adjusted funds flow from operations and projected ratio of net debt to adjusted funds flow from operations using realized pricing and US\$70/bbl and US\$2.00/MMBtu and US\$80/bbl and US\$3.00/MMBtu flat pricing for the remainder of the year. The sensitivity for the ratio of net debt to adjusted funds flow from operations¹ increased to reflect lower realized pricing, minor unplanned production downtime in July, and accelerated capital forecast for 2024.

Kiwetinohk's revised 2024 guidance and related sensitivities provide information relevant to expectations for financial and operational results. This corporate guidance is based on various commodity price scenarios, assumptions and economic conditions and readers are cautioned that guidance estimates may fluctuate and are subject to numerous risks and uncertainties. Kiwetinohk will update guidance if and as required throughout the year. Details of current full year guidance are presented below.

2024 Financial & Operational Guidance		Current July 30, 2024	Previous May 27, 2024
Production (2024 average)¹	Mboe/d	26.0 - 27.5	25.0 - 27.5
Oil & liquids	%	45% - 49%	45% - 49%
Natural gas ¹	%	55% - 51%	55% - 51%
Financial			
Royalty rate	%	7% - 10%	7% - 10%
Operating costs	\$/boe	\$7.25 - \$7.75	\$7.75 - \$8.25
Transportation	\$/boe	\$5.50 - \$6.00	\$5.75 - \$6.25
Corporate G&A expense ²	\$MM	\$23 - \$25	\$23 - \$25
Cash taxes ³	\$MM	\$—	\$—
Capital guidance	\$MM	\$320 - \$340	\$320 - \$340
Upstream	\$MM	\$315 - \$332	\$315 - \$332
DCET	\$MM	\$295 - \$310	\$295 - \$310
Infrastructure, production maintenance and other	\$MM	\$20 - \$22	\$20 - \$22
Power ⁷	\$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	\$MM	\$265 - \$285	\$260 - \$280
US\$80/bbl WTI & US\$3.00/MMBtu HH	\$MM	\$290 - \$310	\$290 - \$315
US\$ WTI +/- \$1.00/bbl ⁶	\$MM	+/- \$1.7	+/- \$2.6
US\$ Chicago +/- \$0.10/MMBtu ⁶	\$MM	+/- \$0.8	+/- \$1.0
CAD\$ AECO 5A +/- \$0.10/GJ ⁶	\$MM	+/- \$0.6	+/- \$0.9
Exchange Rate (CAD\$/US\$) +/- \$0.01 ⁶	\$MM	+/- \$1.8	+/- \$2.4
2024 Net debt to Adjusted Funds Flow from Operations sensitivities^{4,5}			
US\$70/bbl WTI & US\$2.00/MMBtu HH	X	0.9x - 1.0x	0.7x - 0.8x
US\$80/bbl WTI & US\$3.00/MMBtu HH	X	0.7x - 0.8x	0.5x - 0.6x

¹ Net debt to adjusted funds flow from operations is a non-GAAP measure that does not have any standardized meaning under IFRS and therefore may not be comparable to similar measures presented by other entities. Please refer to the section "Non-GAAP and other financial measures" herein for further information.

1 – Approximately 90% of natural gas sales are expected to be to the Chicago market in 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 \$0.2 million reflecting taxes payable by its US marketing 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 scenarios that assume actual realized pricing to date and flat forecast pricing at the indicated levels for the remainder of the year.

6 – Assumes US\$75/bbl WTI, US\$2.50/mmbtu HH, US\$0.80/mmbtu HH - AECO basis differentials and \$0.74 USD/CAD for the remainder of the year.

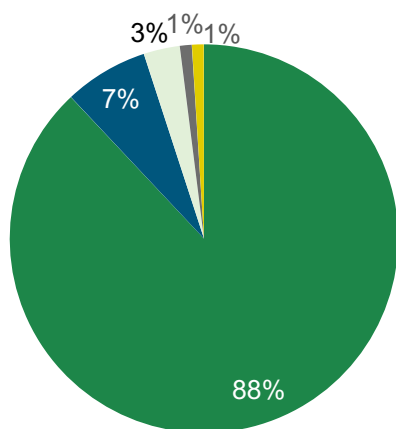
7 – The company has incurred \$3.4 million of costs within the first six months of 2024, and expects remaining expenditures to primarily be expensed for the remainder of the year. Guidance reflected includes capitalized costs and expensed project development costs.

Capital expenditures

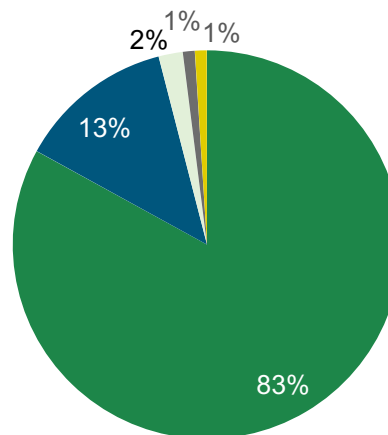
\$000s	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Drilling, completions, and equipping	61,956	36,713	121,783	103,525
Facilities, pipelines, roads and optimization	5,236	17,907	18,846	55,593
Power projects	1,958	3,275	2,918	5,298
Land and other	415	57	870	957
Capitalized G&A - upstream	636	672	1,338	1,668
Capitalized G&A - power	238	181	473	393
Capital expenditures ¹	70,439	58,805	146,228	167,434
Upstream net acquisitions (dispositions) ¹	—	431	(21)	(350)
Capital and net acquisitions (dispositions) ¹	70,439	59,236	146,207	167,084

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.

Capital expenditures
Q2 2024¹



Capital expenditures
YTD 2024¹



1 – Capital expenditures shown are before acquisitions/dispositions.

■ Drilling, completions and equipping ■ Facilities, pipelines, roads and optimization
■ Power projects ■ Land and other ■ Total capitalized G&A

Drilling, completions and equipping

For the three and six months ended June 30, 2024, the Company spent \$62.0 million and \$121.8 million, respectively, on its development program with a focus on the Simonette Duvernay lands. During the second quarter of 2024, the Company executed a two-rig drilling program, drilling a total of 6 wells on two Duvernay pads (three wells on each pad) within the Tony Creek area. Completions activity on these wells commenced at the end

of the second quarter in anticipation of production being on-stream early in the third quarter of 2024. In the first half of 2024, the Company has drilled a total of seven Duvernay wells and one Montney well, and brought three Duvernay wells on-stream that had been drilled and completed in late 2023. The Company anticipates bringing eight additional wells on-stream in the third quarter of 2024, which include 6 wells in the Tony Creek Duvernay, 1 Simonette Duvernay well, and 1 well in the Simonette Montney.

The Company's upstream drilling program remains focused on the 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, with flexibility retained throughout the program to respond to Montney well results.

Facilities, pipelines, roads and optimization

For the three and six months ended June 30, 2024, the Company spent \$5.2 million and \$18.8 million, respectively, on facilities, pipelines, roads and production optimization. The 2024 upstream capital program benefits from upfront investment on infrastructure made in 2023 and requires less infrastructure spending, with a focus on the incremental infrastructure required to manage base production and develop or 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 gas-fired and solar projects with a total estimated nameplate capacity of approximately 2 GW. During the first half of 2024, the Company moderated its development expenditures across the entire portfolio to \$3.4 million, inclusive of capitalized G&A.

The Company is still advancing its Homestead solar project towards a Final Investment Decision ("FID"). Kiwetinohk has engaged a financial advisor to assist in financing the project.

Subsequent to quarter end, the Company received notice from the Alberta Electric Systems Operator ("AESO") that its Phoenix solar project has been removed from Stage 3 of the review process and the Company expects to resubmit the Phoenix solar project application.

At June 30, 2024, an accounting impairment indicator was identified on early-stage development projects, excluding Homestead, related to government policy and regulatory uncertainty. As a result, the Company has limited its capital allocation and an impairment expense of \$29.2 million has been recorded. This represents the book value for the Opal and Little Flipi gas-fired peaking projects; the Granum and Phoenix solar projects and the Black Bear and Flipi natural gas combined-cycle projects. Future development expenditures (excluding Homestead) are expected to be expensed going forward until the Company has a clear line of sight to financing and making a FID on projects under development.

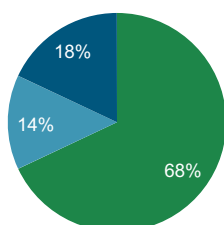
Results of operations

Production

	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Oil & condensate (bbl/d)	7,598	6,398	8,025	6,975
NGLs (bbl/d) ¹	3,817	2,275	3,922	2,395
Natural gas (Mcf/d)	89,259	70,552	89,859	77,003
Total production (boe/d)	26,292	20,432	26,924	22,204
Oil and condensate % of production	29%	31%	30%	31%
NGL % of production	15%	11%	15%	11%
Natural gas % of production	56%	58%	55%	58%
Total production volumes %	100%	100%	100%	100%

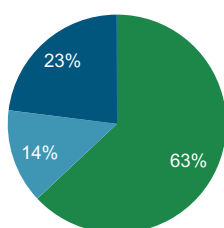
1 - NGL production includes production volumes for ethane (C2), propane (C3), butane (C4) and pentane (C5).

**Revenue Mix (\$)
Q2 2024**



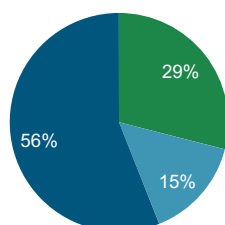
Oil and Condensate
NGLs
Natural Gas

YTD 2024



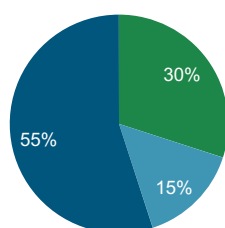
Oil and Condensate
NGLs
Natural Gas

**Production Mix (boe)
Q2 2024**



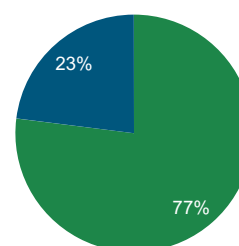
Oil and Condensate
NGLs
Natural Gas

YTD 2024



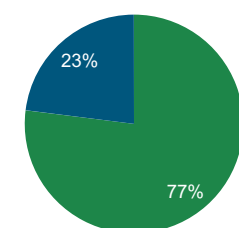
Oil and Condensate
NGLs
Natural Gas

**Production by Area (boe)
Q2 2024**



Simonette
Placid

YTD 2024



Simonette
Placid
Other

Production for the three and six months ended June 30, 2024 increased by 29% to 26,292 boe/d and by 21% to 26,924 boe/d, respectively, compared to the same periods in 2023. The increase in the Company's production volumes is attributable to the capital development program and the Company's continued focus on developing its

core Simonette Duvernay lands, with six incremental wells brought on-stream in the second half of 2023 and three wells brought on-stream in the first quarter of 2024.

The composition of the Company's production portfolio during the six months ended June 30, 2024 was 30% oil and condensate, 15% NGLs, and 55% natural gas, with the production profile becoming more liquids rich compared to the prior period. This change in composition was a result of new wells brought on stream and a marketing decision in the fourth quarter of 2023 to operate the Company's processing facilities at a colder temperature to extract NGLs in Alberta for sale to the Alberta market.

Benchmark and realized prices

	For the three months ended		For the six months ended	
	2024	June 30, 2023	2024	June 30, 2023
Liquid benchmark prices				
WTI (US\$/bbl)	80.57	73.78	78.77	74.95
WTI (CDN\$/bbl)	110.25	99.11	107.03	101.00
Edmonton Light (CDN\$/bbl)	105.28	94.96	98.71	96.99
Natural gas benchmark prices				
Henry Hub (US\$/MMBtu)	1.89	2.10	2.07	2.76
Chicago City Gate MI (US\$/MMBtu)	1.60	1.99	2.05	3.16
Chicago City Gate DI (US\$/MMBtu)	1.65	1.98	2.23	2.31
AECO 5A (CDN\$/GJ)	1.12	2.32	1.74	2.69
AECO 7A (CDN\$/GJ)	1.36	2.22	1.65	3.17
Foreign exchange rates (CAD/USD)	0.73	0.74	0.74	0.74

	For the three months ended		For the six months ended	
	2024	June 30, 2023	2024	June 30, 2023
Realized prices (before impact of hedging program)				
Oil & condensate (\$/bbl)	102.71	91.48	97.25	96.21
NGLs (\$/bbl)	42.21	47.94	44.49	57.14
Natural gas (\$/Mcf)	2.39	3.23	3.11	4.10
Total (\$/boe)	43.91	45.14	45.86	50.60

While crude oil prices have been subject to significant volatility over the past year, average prices for the three and six months ended June 30, 2024 increased from the comparative periods in 2023. In 2024, pricing averaged \$110.25 and \$107.03 per barrel compared to \$99.11 and \$101.00 per barrel, respectively. Increases in benchmark pricing resulted from increased global demand and ongoing sanctions on Russian supply. Edmonton Light benchmark pricing also increased in 2024 compared to 2023, generally driven by the same factors as WTI prices.

NGL sales contracts are negotiated annually in April each year, with pricing for the three and six months ended June 30, 2024 declining when compared to the comparative periods of 2023 primarily as a result of increased North American supply which put downward pressure on contract prices.

Henry Hub natural gas prices decreased to \$1.89 and \$2.07 per Mcf in the three and six months ended June 30, 2024, respectively, when compared to \$2.10 and \$2.76 per Mcf in the comparative periods of 2023. The price declines were due to lower demand as a result of a relatively mild winter in North America coupled with increased North American supply and higher than average inventory levels. The Chicago City Gate monthly benchmark

averaged US \$1.60 and US \$2.05 per MMBtu compared to US \$1.99 and US \$3.16 per MMBtu in the comparative periods of 2023, respectively. The Chicago City Gate monthly index benchmark for natural gas also declined in the three and six months ended June 30, 2024, when compared to prior periods for the same reasons.

Natural gas prices at AECO in Alberta also decreased as new supply outpaced demand and export capacity in the basin. On average, AECO 7A spot prices decreased during the three and six months ended June 30, 2024, when compared to the same periods in 2023, decreasing by \$0.86/GJ to \$1.36/GJ for the second quarter of 2024, and by \$1.52/GJ to \$1.65/GJ for the six months ended June 30, 2024.

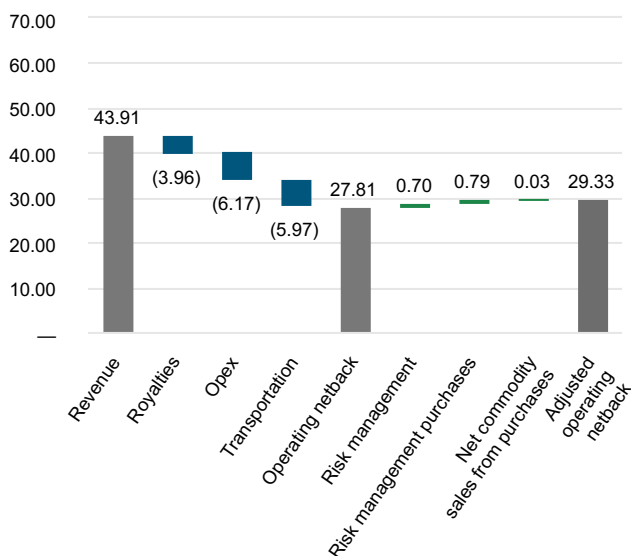
Operating netback

	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Realized price (\$/boe)	43.91	45.14	45.86	50.60
Royalty expenses (\$/boe)	(3.96)	(5.29)	(3.78)	(5.61)
Operating expenses (\$/boe)	(6.17)	(8.82)	(6.61)	(8.19)
Transportation expenses (\$/boe)	(5.97)	(6.06)	(5.27)	(5.68)
Operating netback (\$/boe) ¹	27.81	24.97	30.20	31.12
Realized gain on risk management (\$/boe) ²	0.70	4.58	0.76	2.34
Realized gain on risk management - purchases (\$/boe) ²	0.79	2.06	0.61	2.02
Net commodity sales from purchases (loss) (\$/boe) ¹	0.03	(1.61)	0.12	(0.77)
Adjusted operating netback (\$/boe) ¹	29.33	30.00	31.69	34.71
Total production (boe/d)	26,292	20,432	26,924	22,204

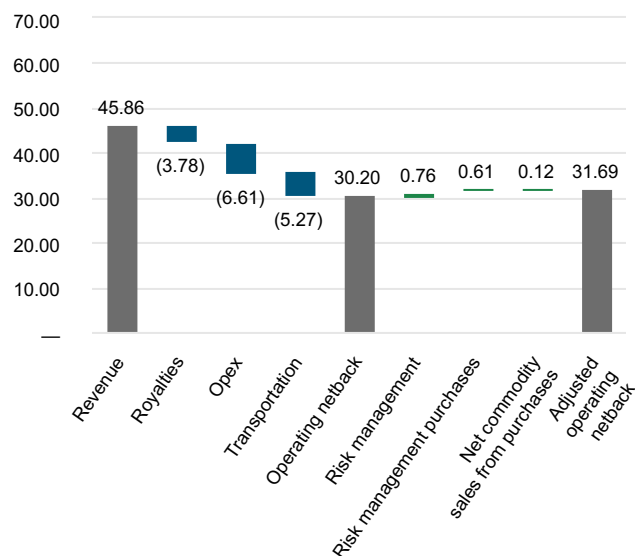
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Q2 2024 (\$/boe)



YTD 2024 (\$/boe)



Operating netback for the three months ended June 30, 2024 was \$27.81/boe compared to \$24.97/boe in the comparable period of 2023. The increase was driven by period over period cost savings achieved across operating expenses, transportation and royalties, partially offset by a reduction in averaged realized prices. During

the six month period, reduced realized pricing outweighed cost savings achieved and resulted in operating netback declining 3% to \$30.20/boe compared to \$31.12/boe in 2023.

Adjusted operating netback for the three and six months ended June 30, 2024, decreased by 3% and 9%, respectively, compared to the same periods in 2023. The Company realized gains of \$1.49/boe and \$1.37/boe on risk management contracts for the three and six months ended June 30, 2024, 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	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Oil & condensate	71,012	53,262	142,031	121,456
NGLs	14,663	9,923	31,760	24,772
Natural gas	19,374	20,750	50,920	57,128
Total commodity sales from production	105,049	83,935	224,711	203,356

Revenue from production increased to \$105.0 million and \$224.7 million, respectively, for the three and six months ended June 30, 2024, representing 25% and 11% respective growth over the comparative periods in 2023. Increases were driven by higher production levels in 2024 achieved through new well additions, partially offset by a decline in average realized pricing relative to 2023. Average price declines were driven by weaker natural gas and NGL benchmarks partially offset by an increase in WTI prices in both the three and six month periods as outlined above.

Net commodity sales from purchases

\$000s	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Commodity sales from purchases	7,353	17,475	23,336	37,973
Commodity purchases, transportation and other	(7,266)	(20,479)	(22,739)	(41,087)
Net commodity sales from purchases (loss) ¹	87	(3,004)	597	(3,114)
Realized hedging gain on purchases	1,882	3,824	2,999	8,103
Net commodity sales from purchases after hedging ¹	1,969	820	3,596	4,989
\$/boe – before hedging	0.03	(1.61)	0.12	(0.77)
\$/boe – after hedging	0.82	0.45	0.73	1.25

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 six months ended June 30, 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 and six months ended June 30, 2024, the Company realized a gain of \$0.1 million and \$0.6 million, respectively, on its marketing activities associated with purchasing natural gas to fulfill its transmission commitment on the Alliance pipeline system. Including the impact of related risk management contracts, the Company realized overall marketing income of \$2.0 million and \$3.6 million for the three and six months ended June 30, 2024, respectively, relative to \$0.8 million and \$5.0 million for the comparable periods 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	For the three months ended		For the six months ended	
	2024	June 30, 2023	2024	June 30, 2023
Risk management:				
Unrealized (loss) gain	(16,820)	8,887	(31,960)	37,698
Realized gain	3,542	12,333	6,677	17,502
Total (loss) gain on risk management	(13,278)	21,220	(25,283)	55,200
Unrealized (loss) gain (\$/boe)	(7.03)	4.78	(6.52)	9.38
Realized gain (\$/boe)	1.49	6.64	1.37	4.36

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

\$000s	For the three months ended		For the six months ended	
	2024	June 30, 2023	2024	June 30, 2023
Realized gain on production	3,234	8,857	5,906	10,830
Realized gain on purchases	1,882	3,824	2,999	8,103
Realized loss on foreign exchange	(1,574)	(348)	(2,228)	(1,431)
Total realized gain	3,542	12,333	6,677	17,502
Realized gain on production (\$/boe)	1.36	4.77	1.21	2.70
Realized gain on purchases (\$/boe)	0.79	2.06	0.61	2.02
Realized loss on foreign exchange (\$/boe)	(0.66)	(0.19)	(0.45)	(0.36)

For the three and six months ended June 30, 2024, the Company recorded realized gains on risk management contracts of \$3.5 million and \$6.7 million, respectively. Approximately 53% of the second quarter and 45% of the current year-to-date gains realized were related to natural gas volumes purchased for resale required to meet

pipeline commitments in excess of the Company's production needs, where the Company hedges price differences between Chicago and Alberta markets at the time of contracting third party natural gas purchases.

Gains were realized on production hedges in the three and six months ended June 30, 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. Hedging gains realized in 2024 declined relative to the 2023 periods driven largely by reduced gains on natural gas hedges carried by the Company where the difference between the hedge contract prices and settlement prices narrowed relative to the prior period.

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

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

The unrealized loss on risk management of \$16.8 million and \$32.0 million during the three and six months ended June 30, 2024, respectively, represents changes in the fair value of risk management contracts outstanding at the end of those periods. As of June 30, 2024 the Company's hedging portfolio was a \$12.4 million liability (net payable) 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 June 30, 2024:

Type		Q3 2024	Q4 2024	2025	2026	2027
Crude oil ¹						
WTI swap	bbl/d	1,750	2,000	563	—	—
WTI buy put	bbl/d	4,167	3,500	2,333	500	42
WTI sell call	bbl/d	3,667	3,000	2,333	500	42
WTI swap average	US\$/bbl	\$74.32	\$73.91	\$74.17	\$—	\$—
WTI buy put average	US\$/bbl	\$69.19	\$69.29	\$69.34	\$70.19	\$70.00
WTI sell call average	US\$/bbl	\$78.79	\$77.18	\$77.07	\$73.38	\$73.18
Natural gas ¹						
NYMEX Henry Hub swap	MMBtu/d	2,500	2,500	—	—	—
NYMEX Henry Hub buy put	MMBtu/d	45,833	40,833	28,958	15,868	863
NYMEX Henry Hub sell call	MMBtu/d	35,833	32,500	28,958	15,868	863
NYMEX Henry Hub swap average	US\$/MMBtu	\$3.23	\$3.23	\$—	\$—	\$—
NYMEX Henry Hub buy put average	US\$/MMBtu	\$3.11	\$3.19	\$3.24	\$3.14	\$3.00
NYMEX Henry Hub sell call average	US\$/MMBtu	\$3.96	\$4.14	\$4.60	\$4.49	\$3.90

Type		Q3 2024	Q4 2024	2025	2026	2027
Natural gas transportation ^{1,2}						
Purchase AECO 5A basis (to NYMEX Henry Hub)	MMBtu/d	30,000	13,333	4,167	—	—
Sell GDD Chicago basis (to NYMEX Henry Hub) ³	MMBtu/d	(30,000)	(13,333)	(4,167)	—	—
AECO 5A basis (to NYMEX Henry Hub) average	US\$/MMBtu	\$(1.28)	\$(1.37)	\$(1.42)	\$—	\$—
GDD Chicago basis (to NYMEX Henry Hub) average ³	US\$/MMBtu	\$(0.07)	\$(0.10)	\$(0.12)	\$—	\$—

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 June 30, 2024:

Type		Q3 2024	Q4 2024	2025	2026	2027
Foreign exchange ¹						
Sell USD CAD (monthly average)	US\$	\$9.0 MM	\$9.0 MM	\$16.5 MM	\$— MM	\$— MM
USD CAD buy put	US\$	\$5.0 MM	\$5.0 MM	\$2.5 MM	\$5.0 MM	\$— MM
USD CAD sell call	US\$	\$5.0 MM	\$5.0 MM	\$2.5 MM	\$5.0 MM	\$— MM
USD CAD fixed sell rate		\$1.33	\$1.33	\$1.34	\$—	\$—
USD CAD put rate		\$1.32	\$1.32	\$1.33	\$1.28	\$—
USD CAD call rate		\$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 (liability) outstanding are as follows:

\$000s	June 30, 2024	December 31, 2023
Short term risk management asset	—	10,708
Long term risk management asset	178	8,838
Short term risk management liability	(9,355)	—
Long term risk management liability	(3,237)	—
Total risk management contracts (liability) asset	(12,414)	19,546

\$000s	June 30, 2024	December 31, 2023
(Liability) asset on produced volumes	(2,980)	9,186
(Liability) asset on purchased volumes	(1,291)	3,616
(Liability) asset on foreign exchange contracts	(8,143)	6,744
Total risk management contracts (liability) asset	(12,414)	19,546

Subsequent to June 30, 2024, the Company entered into the following risk management contracts:

Type		Q3 2024	Q4 2024	2025	2026	2027
Crude oil contracts ^{1,2}						
WTI buy put	bbl/d	333	333	—	—	—
WTI sell call	bbl/d	333	333	—	—	—
WTI buy put average	US\$/bbl	\$70.00	\$70.00	\$—	\$—	\$—
WTI sell call average	US\$/bbl	\$88.50	\$88.50	\$—	\$—	\$—

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

2 – Additional contracts were layered into the Company's existing risk management portfolio as part of the Company's risk management policy. The Company does not seek to speculate on commodity price movements through the hedging program.

Royalty expense

\$000s	For the three months ended		For the six months ended	
	2024	2023	2024	2023
Royalty expense	9,470	9,841	18,537	22,559
As a % of revenue	9.0 %	11.7 %	8.2 %	11.1 %
\$/boe	3.96	5.29	3.78	5.61

The Company pays Crown, freehold, and overriding royalties on production volumes. Royalties for the three and six months ended June 30, 2024 decreased to \$9.5 million and \$18.5 million, respectively, as compared to \$9.8 million and \$22.6 million in the comparative periods of 2023. Royalties as a percentage of revenue for the three and six months ended June 30, 2024 of 9.0% and 8.2% decreased over the same periods in 2023. Decreases in royalties resulted from declines in realized natural gas and NGL 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	For the three months ended		For the six months ended	
	2024	2023	2024	2023
Operating expenses	14,758	16,385	32,383	32,927
\$/boe	6.17	8.82	6.61	8.19

Operating costs include amounts incurred to extract commodities to the surface including expenditures for field operators, gas and liquids processing, gathering and compression, utilities, chemicals and maintenance related costs. Operating costs for the three and six months ended June 30, 2024 were \$14.8 million and \$32.4 million, as compared to \$16.4 million and \$32.9 million, respectively, in the comparable periods of 2023.

On a per barrel basis, operating expenses for the three and six months ended June 30, 2024 decreased by 30% to \$6.17/boe and 19% to \$6.61/boe, respectively, as higher production led to operating efficiencies gained through the Company's owned and operated infrastructure within Simonette. In addition, during the second quarter of 2023, incremental operating costs of \$0.45/boe and \$0.21/boe were incurred in response to the Company's response to Alberta wildfires in the month of May 2023.

Transportation expenses

\$000s	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Transportation expenses	14,280	11,274	25,819	22,822
\$/boe	5.97	6.06	5.27	5.68

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 expenses for the three and six months ended June 30, 2024 were \$14.3 million and \$25.8 million, respectively, as compared to \$11.3 million and \$22.8 million in the respective 2023 periods. Transportation costs increased as a result of higher production, however, per barrel transportation expenses of \$5.97/boe during the second quarter of 2024 were consistent with the second quarter of 2023. On a year to date basis, per barrel transportation costs of \$5.68/boe declined from the comparative period in 2023 as a result of a positive adjustment to 2023 expenses received in the first quarter of 2023. This adjustment reconciled previously paid pipeline obligations to match the actual volumes of goods shipped in 2023, resulting in a reduction to 2024 transportation expenses. Excluding this credit, transportation expenses per barrel for the first half of 2024 would have been consistent with the prior year periods.

Adjusted funds flow from operations

\$000s	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Cash flows from operating activities	61,232	41,360	136,415	121,520
Net change in non-cash working capital from operating activities	(969)	4,701	(1,673)	(2,622)
Asset retirement obligation expenditures	374	258	919	3,402
Adjusted funds flow from operations ¹	60,637	46,319	135,661	122,300
\$/boe	25.34	24.91	27.69	30.43

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

Adjusted funds flow from operations during the three and six months ended June 30, 2024 increased to \$60.6 million and \$135.7 million relative to \$46.3 million and \$122.3 million during the comparative periods in 2023, respectively. Increases on a total basis were driven by growth in the business driven by increased production levels as described above (see operating netback), partially offset by increased financing costs resulting from higher average debt levels outstanding at higher interest rates.

On a per barrel basis, adjusted funds flow from operations during the three and six months ended June 30, 2024 increased by 2% to \$25.34/boe and decreased 9% to \$27.69/boe, respectively, relative to the comparable periods of 2023. Per barrel changes relative to the 2023 periods, are consistent with the changes in adjusted operating netback and adjusted funds flow from operations described above.

Free funds flow from operations

\$000s	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Adjusted funds flow from operations ¹	60,637	46,319	135,661	122,300
Capital expenditures ¹	(70,439)	(58,805)	(146,228)	(167,434)
Free funds flow deficiency from operations ¹	(9,802)	(12,486)	(10,567)	(45,134)
\$/boe	(4.10)	(6.72)	(2.16)	(11.23)

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.

During the three and six months ended June 30, 2024, the Company had a free funds flow deficiency of \$9.8 million and \$10.6 million relative to a deficiency of \$12.5 million and \$45.1 million in the comparative periods 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 cash flow 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	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Gross G&A expenses	6,629	6,811	13,656	12,394
Less capitalized G&A	(874)	(853)	(1,811)	(2,061)
G&A Expenses	5,755	5,958	11,845	10,333
\$/boe	2.41	3.20	2.42	2.57

For the three and six months ended June 30, 2024, the Company incurred gross G&A expenses of \$6.6 million and \$13.7 million, respectively, relative to \$6.8 million and \$12.4 million in the comparable periods in 2023. G&A expenses per barrel decreased over the same periods to \$2.41/boe and \$2.42/boe, respectively, 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 solar and natural gas-fired power generation projects as well as early stage investigation of opportunities to develop carbon capture hubs within Alberta.

Share-based compensation expenses

\$000s	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Equity-settled awards	801	2,411	1,610	3,367
Cash-settled awards	1,867	442	3,137	682
Total share-based compensation expenses	2,668	2,853	4,747	4,049
\$/boe	1.12	1.53	0.97	1.01

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.

Total share-based compensation was \$2.7 million and \$4.7 million for the three and six months ended June 30, 2024 compared to \$2.9 million and \$4.0 million, in the respective prior year periods, with increases largely driven by cash-settled awards with more awards outstanding, stronger relative performance to peers during the first half of 2024, and a higher share price at the end of the 2024 second quarter period.

Finance costs

\$000s	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Interest and bank charges	4,677	4,099	9,339	7,481
Accretion expense	925	855	1,784	1,720
Interest on lease obligations	548	224	1,085	444
Deferred financing amortization	183	269	344	593
Unrealized gain (loss) on foreign exchange	(119)	172	(673)	168
Total finance costs	6,214	5,619	11,879	10,406
\$/boe	2.60	3.02	2.42	2.59

The Company has a \$400 million senior secured extendible revolving facility (the "Credit Facility") with a syndicate of banks. As at June 30, 2024 the Company had drawn \$190.7 million on the facility (June 30, 2023 - \$139.9 million).

The increase in financing costs for the three and six months ended June 30, 2024 is associated with higher average debt levels and higher interest rates when compared to the comparable prior year periods. Average interest rates were approximately 8.4% for the six months ended June 30, 2024 as compared to 7.9% in the comparative period of 2023.

Depletion and Depreciation

\$000s	For the three months ended June 30,		For the six months ended June 30,	
	2024	2023	2024	2023
Depletion	39,555	27,233	81,266	58,673
Depreciation	511	434	1,026	882
Total depletion and depreciation	40,066	27,667	82,292	59,555
\$/boe	16.75	14.88	16.79	14.82

The Company recognized depletion of \$39.6 million and \$81.3 million during the three and six months ended June 30, 2024 compared to \$27.2 million and \$58.7 million during the comparative periods of 2023. Increases in depletion are due to a higher depletion rate combined with increases in period over period production levels.

Depletion per barrel for the three and six months ended June 30, 2024 increased compared to the comparative periods in 2023, due to a greater depletable base resulting from the Company's continued upstream development activity 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

During the six months ended June 30, 2024, the Company incurred approximately \$7.0 thousand in income taxes relating to the Company's United States subsidiary. The Company did not pay any Canadian income taxes in 2023 and does not expect to be taxable in Canada in the near future.

As of June 30, 2024, the Company recognized a net deferred tax liability of \$5.8 million. The Company's estimated tax pools as at June 30, 2024, are as follows:

Category	Deductibility	\$000s
Canadian oil and gas property expense ("COGPE")	10%	178,804
Successored COGPE	10%	1,006
Canadian development expense ("CDE")	30%	270,694
Successored CDE	30%	47,580
Canadian exploration expense ("CEE")	100%	1,241
Undepreciated capital cost ("UCC")	Primarily 25%, declining balance	175,562
Non-capital losses	100%	184,394
Share/Debt issue costs	5-year straight line	3,037
Other	Various	362
Total estimated tax pools		862,680

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 \$114.2 million, or \$176.9 million inflated at 1.80% and undiscounted. These cash flows have been discounted using a risk-free interest rate of 3.39% to arrive at the present value estimate of \$81.5 million.

There is approximately \$25.9 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.

Provision for onerous contract

The Company has recognized a provision related to an onerous contract to transport and offload natural gas from the Nova Gas Transmission Ltd. pipeline system for use at its Opal gas-fired peaking project. The provision represents the future tolling obligations that the Company is presently obligated to make under the contract. The Company estimates the total undiscounted future tolling obligations under this contract to be \$5.1 million. These payments have been discounted using a seven-year risk-free interest rate of 3.49% to arrive at a present value estimate of \$4.5 million (December 31, 2023 – nil). The Company expects to reduce the provision by \$0.7 million over the next twelve months as obligations become due. The estimate may vary as a result of changes in future discount rates and revisions in published tolls over the contract period.

Select quarterly information

(\$000s except per share and production)	2024		2023		2022			
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Production (average boe/d)	26,292	27,556	24,707	21,218	20,432	23,996	24,745	16,487
Commodity sales from production	105,049	119,662	114,038	94,432	83,935	119,421	159,457	122,644
Commodity sales from purchases	7,353	15,983	18,136	19,464	17,475	20,498	47,902	77,623
Cash flow from operating activities	61,232	75,183	58,946	60,294	41,360	80,160	87,028	91,710
Per share (basic)	1.40	1.72	1.35	1.37	0.94	1.81	1.97	2.08
Per share (diluted)	1.39	1.71	1.33	1.36	0.93	1.79	1.94	2.05
Net (loss) income	(26,538)	11,092	48,302	(12,056)	21,701	53,949	115,308	55,379
Per share (basic)	(0.61)	0.25	1.11	(0.27)	0.49	1.22	2.61	1.26
Per share (diluted)	(0.61)	0.25	1.09	(0.27)	0.49	1.21	2.57	1.24

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 27, 2024 the Company completed the annual borrowing base review of the consolidated Credit Facility and increased the borrowing base from \$375.0 million to \$400.0 million. The borrowing base is comprised of an operating facility of \$65.0 million and a syndicated facility of \$335.0 million.

At June 30, 2024, \$190.7 million was outstanding on the Credit Facility before deferred financing costs (December 31, 2023 - \$195.0 million) along with \$81.6 million (December 31, 2023 - \$89.4 million) in letters of credit issued to support transportation and other commitments. Of the \$81.6 million letters of credit, \$57.9 million were provided for through the EDC facility (see below), and the remaining \$23.7 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	400,000	190,667	23,736	185,597
EDC Facility	125,000	—	57,896	67,104
Total				252,701

\$000s	June 30, 2024	December 31, 2023
Credit facility drawn	190,667	195,000
Deferred financing costs	(1,488)	(912)
Loans and borrowings	189,179	194,088
Adjusted working capital deficit (surplus) ¹	17,447	(7,565)
Net debt ¹	206,626	186,523
Annualized adjusted funds flow from operations ¹	254,672	241,311
Net debt to annualized adjusted funds flow from operations ¹	0.81	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, 2025, 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, 2026. 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 Canadian Overnight Repo Rate Average ("CORRA") 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 (June 30, 2024 - 0.81 times).

EDC letter of credit facility

On May 27, 2024, Kiwetinohk amended and increased the unsecured demand revolving letter of credit facility (the "LC Facility") with Export Development Canada ("EDC") from \$75.0 million to \$125.0 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, 2025 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 2025 concurrently with its annual borrowing base review of the consolidated Credit Facility. At June 30, 2024, the Company has \$67.1 million of capacity remaining under the LC Facility (December 31, 2023 - \$8.9 million).

Base shelf prospectus

The Company filed a final short-form base shelf prospectus ("Prospectus") on May 27, 2024. 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 and other opportunities. It provides Kiwetinohk with the ability to issue up to \$500 million of securities over a period of 25 months, if and when desirable. There are no immediate plans to raise equity, debt or other forms of financing and net proceeds from the sale of any securities issued under the Prospectus could have a wide range of uses including to complete asset or corporate acquisitions, to finance potential future growth opportunities, to repay indebtedness, to finance the Company's ongoing capital program, or for other general corporate purposes.

Share capital

The Company is authorized to issue an unlimited number of voting common shares 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 any shares under the NCIB program during the six months ended June 30, 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)	For the three months ended		For the six months ended	
	2024	June 30, 2023	2024	June 30, 2023
Weighted average shares outstanding				
Basic	43,667	44,073	43,665	44,147
Diluted	44,149	44,475	44,029	44,625
Outstanding securities				
Common shares	43,668	43,981	43,668	43,981
Stock options ¹	2,740	2,596	2,740	2,596
Performance warrants ¹	6,708	6,839	6,708	6,839
Total diluted outstanding securities	53,116	53,416	53,116	53,416

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 July 30, 2024, the Company has 43,668,489 Common Shares and no preferred shares outstanding.

Commitments, contractual obligations, and contingencies

\$ millions	2024	2025	2026	2027	2028	Thereafter
Accounts payable	59.6	—	—	—	—	—
Cash-settled compensation liability ¹	2.8	1.4	0.4	—	—	1.7
Loans and borrowings ²	—	—	190.7	—	—	—
Risk management contracts	7.2	2.7	2.3	0.2	—	—
Gathering, processing and transport	38.4	67.4	15.0	16.4	16.5	22.1
Natural gas purchases	7.5	—	—	—	—	—
Upstream and corporate lease liabilities	1.0	2.2	2.2	2.2	2.2	6.3
Power lease liabilities ³	1.3	2.0	1.3	1.3	1.3	25.9
Power construction	0.6	—	—	—	—	—
Other	—	0.4	0.4	0.4	0.4	0.4
Total	118.4	76.1	212.3	20.5	20.4	56.4

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 June 30, 2024.

Related party information

For the three and six months ended June 30, 2024, the Company incurred a total of \$0.5 million and \$0.7 million, respectively (June 30, 2023 – \$0.1 million and \$0.3 million), in the following related party transactions:

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

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.

Risk factors and risk management

The Company's management team is focused on long-term strategic planning and has identified key material risks, uncertainties and opportunities associated with the Company's business that can impact the financial position, operations, cash flows and future prospects of the business. There were no significant changes in key risks identified during the three and six months ended June 30, 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 April 1, 2024, and ending on June 30, 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 and six months ended June 30, 2024.

Critical accounting estimates

The significant accounting judgements and estimates used by the Company are discussed in the notes to the December 31, 2023 audited 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 how the Company evaluates critical accounting estimates and judgments during the three and six months ended June 30, 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 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 (loss) income and comprehensive (loss) income to the extent the Company has outstanding financial instruments.

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

Off-balance sheet arrangements

Except as disclosed in the Financial Statements, the Company has not entered into any guarantee or off-balance sheet arrangements that would materially impact the financial position or results of operations as at June 30, 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	For the three months ended		For the six months ended	
	2024	June 30, 2023	2024	June 30, 2023
Commodity sales from production	105,049	83,935	224,711	203,356
Royalty expenses	(9,470)	(9,841)	(18,537)	(22,559)
Operating expenses	(14,758)	(16,385)	(32,383)	(32,927)
Transportation expenses	(14,280)	(11,274)	(25,819)	(22,822)
Operating netback	66,541	46,435	147,972	125,048
Realized gain on risk management	1,660	8,509	3,678	9,399
Realized gain on risk management - purchases	1,882	3,824	2,999	8,103
Net commodity sales from purchases (loss)	87	(3,004)	597	(3,114)
Adjusted operating netback	70,170	55,764	155,246	139,436

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	For the three months ended		For the six months ended	
	2024	2023	2024	2023
Cash flow used in investing activities	66,052	80,171	135,335	182,272
Net change in non-cash investing working capital	4,387	(20,685)	11,857	(4,938)
Power connection process payment	—	—	(985)	—
Settlement of contingent consideration	—	(250)	—	(10,250)
Capital expenditures and net acquisitions (dispositions)	70,439	59,236	146,207	167,084
Proceeds from disposition	—	—	21	781
Net acquisitions (dispositions)	—	(431)	21	350
Capital expenditures	70,439	58,805	146,228	167,434

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

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

Non-GAAP Financial Ratios

Operating netback per boe & adjusted operating netback per boe

“Operating netback per boe” and “adjusted operating netback per boe” is calculated as operating netback and adjusted operating netback, respectively, divided by total production for the period 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.

Capital Management Measures

Adjusted funds flow from operations

“Adjusted funds flow from operations” is cash flow from operating activities before changes in net change in non-cash working capital from operating activities, asset retirement obligations, and 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	June 30, 2024	December 31, 2023
Current assets	55,724	87,951
Current liabilities	(82,526)	(69,678)
Working capital (deficit) surplus	(26,802)	18,273
Short term risk management contracts net liability (asset)	9,355	(10,708)
Adjusted working capital (deficit) surplus	(17,447)	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 upstream asset's competitive economic resource potential and development upside;
- the Power business unit's development strategy to enable the production of reliable, dispatchable, affordable and cleaner energy than what is available through Alberta's grid today;
- the Company's detailed 2024 financial and operational guidance and adjustments to the previously communicated 2024 guidance, including anticipated increase in production, reduction in operating costs, reduction in transportation costs, and revised sensitivities in adjusted funds flow from operations and related ratio of net debt to adjusted funds flow from operations;
- 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 surrounding the Company's Phoenix solar project, including regulatory applications and approvals related thereto;
- the Company's continued advancement of the Homestead solar project towards an FID decision;
- receipt of further clarity from provincial and federal governments regarding pending electricity regulations;
- the anticipated outcomes of successful execution of the Company's investment and financing strategies for its power project portfolio;
- 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;
- operating and capital costs in 2024;
- sufficiency of funds to meet the Company's working capital requirements and anticipated drilling through 2024;
- the Company's ability to reduce the provision under its contract to transport and offload natural gas from the Nova Gas Transmission Ltd. pipeline system for use at its Opal gas-fired peaking project.
- timing for the next scheduled redetermination of the borrowing base on the Company's consolidated Credit Facility and EDC letter of credit facility;
- use of the Credit Facility for working capital purposes to fund go forward capital plans;
- the Company's future plans to potentially issue securities under the Prospectus and the possible use of proceeds therefrom;
- 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 Company's expectations regarding material adverse litigation;
- 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 and conflict in the Middle East) 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 and conflict in the Middle East) 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;
- risks related to the interpretation of, and/or potential claims made pursuant to, the Government of Canada amendments to the deceptive marketing practices provisions of the Competition Act (Canada) regarding greenwashing; 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
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
DI	daily index
FID	Final Investment Decision
GJ	gigajoule
GW	one billion watts
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
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

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Bankers

Bank of Montreal

ATB Financial

National Bank of Canada

Royal Bank of Canada

Bank of Nova Scotia

Business Development Bank of Canada

Auditor

Deloitte LLP

Calgary, AB

Board of Directors

Kevin Brown

Board Chair

Beth Reimer-Heck

Lead Director

Judith Athaide

Director

Colin Bergman

Director

Pat Carlson

Director and Chief Executive Officer

Leland Corbett

Director

Kaush Rakhit

Director

Steve Sinclair

Director

John Whelen

Director

Reserve Engineers

McDaniel & Associates Consultants Ltd.

Calgary, AB

Legal Counsel

Stikeman Elliot LLP

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Transfer Agent

Computershare

Calgary, AB

Stock Symbol

KEC

Toronto Stock Exchange