Hammerhead Resources Inc.

Management's Discussion and Analysis
As at and for the Three and Nine Months Ended
September 30, 2022

Dated: November 17, 2022

Management Discussion and Analysis

In this management's discussion and analysis ("MD&A"), unless otherwise indicated or the context otherwise requires, the terms "we", "us", "our", "HHR", "Hammerhead" and "the Company" refers to Hammerhead Resources Inc., as the parent corporation.

Hammerhead is an oil and natural gas exploration, development and production company. Hammerhead's reserves, producing properties and exploration prospects are located in the province of Alberta in the Deep Basin of West Central Alberta where it is developing multi-zone, liquids-rich oil and gas plays. The Company is controlled by Riverstone Holdings LLC. The Company's head office is located at Eighth Avenue Place, East Tower, Suite 2700, 525-8th Avenue SW, Calgary, Alberta, T2P 1G1.

This MD&A contains forward-looking statements and non-GAAP measures. Readers are cautioned that the MD&A should be read in conjunction with the Company's disclosures under the headings "Forward-Looking Statements" and "Other Advisories - Non-GAAP Financial Measures" included at the end of this MD&A.

The following MD&A provides management's analysis of the Company's results of operations and financial position as at and for the three and nine months ended September 30, 2022. This MD&A is dated November 17, 2022 and should be read in conjunction with the unaudited condensed interim consolidated financial statements as at and for the three and nine months ended September 30, 2022 (the "Interim Financial Statements"), the audited consolidated financial statements as at and for the year ended December 31, 2021 (the "2021 Annual Financial Statements") and the 2021 annual MD&A (the "2021 Annual MD&A").

Refer to the "Non-GAAP and Other Specified Financial Measures" section of this MD&A for reconciliations and information regarding the following measures and ratios used in this MD&A: "capital expenditures", "available funding", "operating netback", "operating netback per boe", "funds from operations", "funds from operations per boe", "funds from operations per basic share and diluted share", "adjusted EBITDA and annualized quarterly adjusted EBITDA", "net debt" and "net debt to annualized quarterly adjusted EBITDA".

All financial information has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") as set out in Part I of the *CPA Canada Handbook – Accounting*, using accounting polices consistent with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Unless otherwise noted, all financial information provided herein is reported in Canadian dollars and tabular dollar amounts are presented in thousands. Production volumes are presented on a working-interest basis before royalties.

Operational and Financial Summary

(Cdn$ thousands, except per share amounts, production and unit prices)	Three Months Ended September 30, 2022	2021	% Change	Nine Months Ended September 30, 2022	2021	% Change
Production volumes						
Crude oil (bbls/d)	9,279	5,854	59	9,724	6,709	45
Natural gas (Mcf/d)	111,353	95,304	17	113,899	103,020	11
Natural gas liquids (bbls/d)	4,273	3,014	42	4,234	3,940	7
Total (boe/d)	32,111	24,752	30	32,941	27,819	18
Liquids weighting %	42	36		42	38	
Oil and gas revenue ($/boe)	69.91	45.25	54	71.83	39.59	81
Operating netback ($/boe) [1]	34.77	13.01	167	37.63	14.44	161
Oil and gas revenue	206,518	103,047	100	645,968	300,660	115
Operating netback [2]	102,689	29,616	247	338,470	109,621	209
Net cash from operating activities	95,138	25,492	273	295,224	87,571	237
Per common share – basic	0.24	0.07		0.75	0.22	
Per common share – diluted	0.10	0.07		0.31	0.22	
Funds from operations [3]	76,545	22,654	238	298,878	84,144	255
Per common share – basic [4]	0.20	0.06		0.76	0.22	
Per common share – diluted [4]	0.08	0.06		0.31	0.22	
Net profit (loss)	67,251	(25,319)	(366)	157,802	(108,960)	(245)
Net profit (loss) attributable to ordinary equity holders	60,782	(30,903)	(297)	139,281	(124,945)	(211)
Per common share – basic	0.15	(0.08)		0.36	(0.32)	
Per common share – diluted	0.06	(0.08)		0.15	(0.32)	
Net cash used in investing activities	58,669	20,809	182	222,597	48,990	354
Capital expenditures [5]	77,332	39,606	95	210,207	70,159	200
Weighted average common shares outstanding						
Basic	392,309	391,113	—	391,549	391,102	—
Diluted	967,757	391,113	147	957,324	391,102	145

FINANCIAL	As at September 30, 2022	2021	% Change
Working capital deficit	60,498	91,800	(34)
Available funding [6]	304,402	165,100	84
Net debt [7]	245,912	314,167	(22)

1 Operating netback per boe is a non-GAAP measure. Oil and gas revenue per boe is the most directly comparable GAAP measure to operating netback per boe. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.
2 Operating netback is a non-GAAP measure. Oil and gas revenue is the most directly comparable GAAP measure to operating netback. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.
3 Funds from operations is a non-GAAP measure. Net cash from operating activities is the most directly comparable GAAP measure to funds from operations. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.
4 Funds from operations per basic and diluted common share are non-GAAP measures. Net cash from operating activities per basic and diluted share are the most directly comparable GAAP measure to funds from operations per basic and diluted common share. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.
5 Capital expenditures is a non-GAAP measure. Net cash used in investing activities is the most directly comparable GAAP measure to capital expenditures. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.
6 Available funding is a non-GAAP measure. Working capital deficit is the most directly comparable GAAP measure to available funding. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.
7 Net debt is a non-GAAP measure. The Company's third party debt obligations of the bank debt and the term debt are the most directly comparable GAAP measures for net debt. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

Third Quarter 2022 Operating and Financial Highlights:

- Production averaged 32,111 boe/d in the third quarter of 2022, a 7,359 boe/d increase from the same period of 2021. New production from 28 gross (28 net) wells brought on-stream since September 30, 2021 offset production declines on existing wells.

- The Company's liquids weighting was 42% during the third quarter of 2022, compared to 36% in the same period of 2021. The increase was driven by high oil production from multiple pads brought on-stream throughout 2022.

- Oil and gas revenue for the three months ended September 30, 2022 and 2021 was $206.5 million and $103.0 million, respectively. Operating netback was $102.7 million or $34.77/boe for the third quarter of 2022, reflecting an increase of $73.1 million or $21.76/boe from the same period of 2021. The increase was driven by improvements in commodity pricing which generated $24.66/boe of additional revenue and a $2.15/boe decrease in realized losses on risk management contracts. This was partially offset by a $6.33/boe increase in royalty expense.

- Net cash from operating activities for the three months ended September 30, 2022 and 2021 was $95.1 million and $25.5 million, respectively. Funds from operations was $76.5 million during the third quarter of 2022, a $53.9 million or 238% increase from the same quarter of 2021. The increase is primarily due to a $73.1 million increase in operating netback, partially offset by a $16.0 million increase in transaction costs, coupled with a $2.6 million increase in cash interest expense and a $2.0 million increase in realized foreign exchange loss from the repayment of the 2020 Senior Notes.

- The Company reported a net profit of $67.3 million for the three months ended September 30, 2022, compared to a net loss of $25.3 million in the same period of 2021 due to a $59.1 million increase in funds from operations and a $54.1 million increase in unrealized gain on risk management contracts, partially offset by non-cash impacts of $20.6 million.

- Net cash used in investing activities for the three months ended September 30, 2022 and 2021 was $58.7 million and $20.8 million, respectively. Capital expenditures during the third quarter of 2022 were $77.3 million primarily consisting of the drill of a nine gross (nine net) well pad and the drill of one gross (0.35 net) development well in Karr, as well as facility and pipeline expansion projects in Karr.

- Effective September 26, 2022, the Company repaid, at par value, US$59.3 million of principal and accrued interest on its 2020 Senior Notes, reducing the aggregate principal balance outstanding down to US$56.5 million.

- On September 26, 2022, the Company announced that it had entered into a business combination agreement with Decarbonization Plus Acquisition Corporation IV ("DCRD"), an affiliate of Riverstone Investment Group LLC, to form a publicly traded company listed on the NASDAQ. The transaction is expected to close before the end of the first quarter of 2023, subject to customary closing conditions, including the receipt of necessary regulatory approvals.

- For the three months ended September 30, 2022 the Company incurred $16.0 million in transaction costs related to the pending business combination with DCRD.

Year-to-Date 2022 Operating and Financial Highlights:

- Production averaged 32,941 boe/d for the nine months ended September 30, 2022, a 5,122 boe/d increase from the same period of 2021. New production from 28 gross (28 net) wells brought on-stream since September 30, 2021 offset production declines on existing wells.

- The Company's liquids weighting was 42% during the nine months ended September 30, 2022, compared to 38% in the same period of 2021. The increase was driven by high oil production from multiple pads brought on-stream throughout 2022.

- Oil and gas revenue for the nine months ended September 30, 2022 and 2021 was $646.0 million and $300.7 million, respectively. Operating netback was $338.5 million or $37.63/boe for the nine months ended September 30, 2022, reflecting an increase of $228.8 million or $23.19/boe from the same period of 2021. Improvements in commodity pricing generated $32.24/boe of additional revenue, which was partially offset by a $5.91/boe increase in royalty expense and a $2.62/boe increase in realized losses on risk management contracts.

- Net cash from operating activities for the nine months ended September 30, 2022 and 2021 was $295.2 million and $87.6 million, respectively. Funds from operations was $298.9 million during the nine months ended September 30, 2022, a

$214.7 million or 255% increase from the same period of 2021. The increase is primarily due to a $228.8 million increase in operating netback, a $6.0 million decrease in optimization fees, and a $2.0 million increase in other cash impacts. This was offset with a $16.0 million increase in transaction costs, a $2.3 million increase in realized foreign exchange loss and a $2.1 million increase cash interest expense related to the repayment of the 2020 Senior Notes, as well as a $1.8 million increase in G&A expense.

- The Company reported a net profit of $157.8 million for the nine months ended September 30, 2022, compared to a net loss of $109.0 million in the same period of 2021. The $266.8 million improvement was primarily due to a $219.9 million increase in funds from operations and a $67.3 million increase in unrealized gain on risk management contracts. This was partially offset by all remaining non-cash impacts decreasing net profit by $20.4 million.

- Net cash used in investing activities for the nine months ended September 30, 2022 and 2021 was $222.6 million and $49.0 million, respectively. Capital expenditures during the nine months ended September 30, 2022 were $210.2 million, with the Company focusing its investments on well development activities in both the Gold Creek and Karr areas, along with spending on non-well activities in the Karr area. In Karr, the Company drilled, completed and tied-in a four gross (four net) well pad, the drill and tie-in activity of a nine gross (nine net) well pad, and initiated drill activity on one gross (0.35 net) development well. The remaining funds incurred in Karr were primarily related to facility and pipeline expansion projects. In Gold Creek, the Company drilled, completed and tied-in two pads with a combined nine gross (nine net) wells and initiated construct, drill and tie-in activity on a three gross (three net) pad.

Results of Operations

Production

	Three Months Ended September 30,			Nine Months Ended September 30,		
	2022	2021	% Change	**2022**	2021	% Change
Crude oil and field condensate (bbls/d)	**9,279**	5,854	59	**9,724**	6,709	45
Natural gas (Mcf/d)	**111,353**	95,304	17	**113,899**	103,020	11
Natural gas liquids (bbls/d)	**4,273**	3,014	42	**4,234**	3,940	7
Total (boe/d)	**32,111**	24,752	30	**32,941**	27,819	18
Liquids weighting %	**42**	36		**42**	38	

Average production during the three months ended September 30, 2022, was 32,111 boe/d, up 30% from the third quarter of 2021. During the nine months ended September 30, 2022, average production was 32,941 boe/d, up 18% from the same period of 2021. The growth in production reflects 28 gross (28 net) wells brought on-stream since September 30, 2021, which offset production declines on existing wells.

The Company's liquids weighting was 42% for both the three and nine months ended September 30, 2022, compared to 36% and 38% for the same periods in 2021. The increase in liquids weighting was driven by higher oil production from multiple pads brought on-stream throughout 2022.

Realized Prices and Benchmark Prices

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Per unit amounts)	2022	2021	% Change	2022	2021	% Change
Average Realized Prices						
Crude oil and field condensate ($/bbl)	117.28	83.80	40	123.64	75.61	64
Natural gas ($/Mcf) [1]	7.84	4.77	64	7.43	3.96	88
Natural gas liquids ($/bbl)	66.37	58.12	14	74.96	47.29	59
Total ($/boe)	69.91	45.25	54	71.83	39.59	81
Benchmark Prices						
Crude oil						
WTI (Cdn$/bbl)	119.57	88.89	35	125.85	81.09	55
Edmonton Light Sweet (Cdn$/bbl)	116.89	83.76	40	123.49	75.91	63
WTI/Edmonton Light Sweet (Cdn$/bbl)	(2.68)	(5.14)	(48)	(2.36)	(5.18)	(54)
Natural gas						
AECO 5A (Cdn$/GJ)	3.94	3.41	16	5.10	3.10	65
AECO 5A (Cdn$/Mcf) [2]	4.20	3.63	16	5.43	3.30	65
NYMEX (US$/MMBtu)	8.18	4.01	104	6.77	3.18	113
NYMEX (Cdn$/Mcf) [2]	10.80	5.10	112	8.79	4.02	119
Union-Dawn (US$/MMBtu)	7.37	4.06	82	6.35	3.26	95
Union-Dawn (Cdn$/Mcf) [2]	9.71	5.16	88	8.24	4.12	100
Chicago City-Gate (US$/MMBtu)	7.38	4.10	80	6.34	5.22	21
Chicago City-Gate (Cdn$/Mcf) [2]	9.73	5.21	87	8.22	6.63	24
Stanfield (US$/MMBtu)	7.27	4.23	72	6.25	3.38	85
Stanfield (Cdn$/Mcf) [2]	9.58	5.38	78	8.11	4.27	90
Malin (US$/MMBtu)	7.52	4.30	72	6.40	3.44	85
Malin (Cdn$/Mcf) [2]	9.92	5.47	79	8.31	4.35	90
Average foreign exchange						
Exchange rate - US$/Cdn$	1.31	1.26	4	1.28	1.25	2

1 At the Company's current heating value of 42.0 GJ/e^3m^3, 1 mcf of natural gas is approximately 1.18 GJ.
2 At industry average heating values of 37.8 GJ/e^3m^3, 1 mcf of natural gas is approximately 1.065 GJ.

Crude oil and field condensate

The majority of the Company's crude oil and field condensate production is delivered and sold in Central Alberta through firm service commitments on Pembina's pipeline systems. The price that Hammerhead receives for crude oil and field condensate production is primarily driven by global supply and demand and the Edmonton light sweet oil and condensate price differentials.

During the three and nine months ended September 30, 2022, the Company's realized crude oil and field condensate price increased by $33.48/bbl or 40% and $48.03/bbl or 64%, respectively, compared to the same periods in 2021. Improved pricing was driven by a rise in demand for oil products coupled with diminished supply from low levels of inventory experienced worldwide and sanctions on Russian oil exports issued in response to the Russia-Ukraine war. Though prices have improved over the 2021 period, volatility persists from the global concern over a potential economic recession and China's impact on demand as it maintains its zero COVID-19 policy.

Natural Gas

The Company's natural gas transportation capacity provides geographical diversification across North America. The Company has firm service commitments to deliver and sell its natural gas production to the Alberta, Eastern Canada and United States (Midwest and West Path) markets.

	Three Months Ended September 30,		Nine Months Ended September 30,	
% weighting of total gas sales	**2022**	2021	**2022**	2021
Alberta	**46**	39	**47**	43
Eastern Canada	**30**	33	**29**	31
United States	**24**	28	**24**	26

For the three and nine months ended September 30, 2022, Hammerhead's realized natural gas price increased by $3.07/mcf or 64%, and $3.47/mcf or 88%, respectively, compared to the same periods in 2021. The increase in the Company's realized price was driven by improvements in benchmark prices across all North American markets.

During the three and nine months ended September 30, 2022, North American prices increased due to high demand from liquified natural gas ("LNG") facilities as European markets experienced supply uncertainty due to the Russia-Ukraine war. Prices in Alberta were impacted by third party pipeline maintenance which kept AECO prices comparatively lower than other North American markets.

NGL

The Company's plant condensate and product mix of NGL are currently sold on the Alberta market, but achieve geographical diversification in pricing through Pembina Pipeline's marketing pool. Pembina operates a pool of sales that provide accessibility to the United States, Asia and Eastern Canadian markets, with market weightings adjusted for supply and demand outlook, as well as seasonality.

Changes in NGL production mix yields for the three and nine months ended September 30, 2022, compared to the same periods of the prior year, were primarily due to operational and maintenance issues at a third party processing plant.

	Three Months Ended September 30,		Nine Months Ended September 30,	
% weighting of total NGL production	**2022**	2021	**2022**	2021
Pentane & plant condensate	**29**	32	**27**	30
Butane	**35**	32	**34**	32
Propane	**35**	31	**37**	36
Ethane	**1**	5	**2**	2

For the three and nine months ended September 30, 2022, Hammerhead's realized NGL price increased by $8.25/bbl or 14%, and $27.67/bbl or 59%, respectively, compared to the same periods in 2021. Higher demand for North American NGL products and diminished supply from low inventory levels compounded by political unrest from the Russia-Ukraine war, drove improvements in pricing for the three and nine months ended September 30, 2022. Warmer weather and inventory recoveries in the US during the third quarter of 2022 tempered these price improvements.

Revenue

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change
Crude oil and field condensate	**100,118**	45,131	122	**328,212**	138,493	137
Natural gas	**80,307**	41,804	92	**231,106**	111,294	108
Natural gas liquids	**26,093**	16,112	62	**86,650**	50,873	70
Oil and gas revenue	**206,518**	103,047	100	**645,968**	300,660	115
Revenue - $/boe	**69.91**	45.25	54	**71.83**	39.59	81

For the three and nine months ended September 30, 2022, the Company earned revenue of $206.5 million and $646.0 million, respectively, compared to $103.0 million and $300.7 million in the comparative periods of 2021. The increase in both periods is primarily due to higher realized prices across all commodities, with additional production further contributing to the rise in revenue.

Royalty Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change
Royalty expense	**31,728**	10,053	216	**81,653**	24,066	239
Royalty expense - $/boe	**10.74**	4.41	144	**9.08**	3.17	186
Percentage of revenue	**15**	10		**13**	8	

Hammerhead pays royalties to the Province of Alberta in respect to the Company's production and sales volumes in accordance with the established royalty regime. The majority of the Company's royalties are paid to the Crown, which are based on various sliding scales that are dependent on incentives, production volumes and commodity prices. Hammerhead's wells spud on or after January 1, 2017 qualify for the Crown's Modernized Royalty Framework ("MRF") incentive program which has a low initial 5% royalty rate until a threshold return of capital has been achieved. As of the latter half of 2018 and up until April 2022, the Company qualified for the Crown's Enhanced Hydrocarbon Recovery Program ("EHRP") associated with a pilot waterflood program in a portion of the Company's Gold Creek area. The EHRP provided for a flat royalty of 5% on all commodities produced from specific wells impacted by the waterflood program.

The Company receives a monthly Gas Cost Allowance ("GCA") credit from the Province of Alberta for expenses incurred to process and transport the Crown's portion of natural gas production. The credit is applied to the royalties that would have been owed to the Crown. The GCA credit is assessed annually every June and is subject to a true-up adjustment as a payable to the Crown or a receivable in the form of a credit to the Company.

During the third quarter of 2022, royalty expenses increased $21.7 million or $6.33/boe compared to the third quarter of 2021. On a percentage of revenue basis, royalties increased by 5% over the same period. During the nine months ended September 30, 2022, royalty expenses increased $57.6 million or $5.91/boe, compared to the same period of 2021. On a percentage of revenue basis, royalties increased by 5% over the same period.

Higher commodity prices for the three and nine months ended September 30, 2022 drove the substantial increase in royalties, when compared to the same periods of 2021. Improved pricing caused higher overall royalty rates with the added impact of fewer wells receiving an incentivized rate. With improved pricing, the period in which new wells are capturing an incentivized rate is being reduced due to the higher prices causing wells to achieve their threshold return of capital sooner. The increase in royalty expense was slightly offset by a higher GCA credit for the three and nine months ended September 30, 2022 due to an unfavourable GCA cost adjustment incurred in the third quarter of 2021.

Operating Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change
Gas gathering and processing	**10,759**	9,786	10	**31,180**	29,707	5
Chemicals and fuel	**5,355**	2,520	113	**14,332**	7,886	82
Repairs and maintenance	**2,979**	3,490	(15)	**12,043**	7,688	57
Staff and contractor costs	**2,542**	1,595	59	**7,315**	6,016	22
Well servicing	**413**	488	(15)	**2,012**	1,306	54
Other	**4,164**	3,237	29	**12,907**	8,716	48
Operating expense	**26,212**	21,116	24	**79,789**	61,319	30
Operating expense - $/boe	**8.87**	9.27	(4)	**8.87**	8.07	10

For the three months ended September 30, 2022, operating expense was $26.2 million or $8.87/boe, compared to $21.1 million or $9.27/boe for the same period of 2021. The increase of $5.1 million was driven by higher chemicals and fuel, gas gathering and processing, staff and contractor costs and other operating costs in line with increased volumes, resulting in a decrease of $0.40/boe.

Higher chemicals and fuel expense is due to higher per unit pricing, coupled with higher consumption as a result of increased production. The rise in gas gathering and processing fees was caused by higher firm service commitments partially offset by increased volumes. Staff and contractor costs increased due to a higher headcount and an overall increase in contractor rates as the 2021 rate reduction was removed. Other operating expense increased due to more waste trucking and disposal costs incurred by high flowback volumes from new wells requiring trucking to alternative tank locations, and from increased equipment rentals due to additional compressors rented in the 2022 period. Lower repair and maintenance charges reflect no battery turnarounds in the third quarter of 2022, with one corresponding turnaround in the third quarter of 2021.

For the nine months ended September 30, 2022, operating expense increased $18.5 million or $0.80/boe, respectively, compared to the corresponding periods of 2021. The increase is due to higher chemicals and fuel charges, repairs and maintenance charges and other operating costs. Higher per unit pricing and consumption drove the increased chemicals and fuel expense. The rise in repairs and maintenance charges reflects three battery turnarounds performed in the second quarter of 2022, with only one corresponding turnaround in the nine months of 2021. The increase in other operating costs is primarily due to higher carbon tax expense, resulting from a change in rates under the Government TIER program, higher water, emulsion and waste disposal costs related to high flowback volumes from new wells, and higher equipment rentals from new rental compressors added in the 2022 period.

Transportation Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands)	2022	2021	% Change	2022	2021	% Change
Transportation expense - gross	17,582	15,563	13	52,481	46,623	13
Transportation income	—	(8)	(100)	—	(168)	(100)
Net transportation expense	17,582	15,555	13	52,481	46,455	13

(Cdn$ per boe)						
Transportation expense - gross	5.95	6.83	(13)	5.84	6.14	(5)
Transportation income	—	—	—	—	(0.02)	(100)
Net transportation expense	5.95	6.83	(13)	5.84	6.12	(5)

During the three months ended September 30, 2022, gross transportation expense was $17.6 million or $5.95/boe, compared to $15.6 million or $6.83/boe in the same period of 2021. During the nine months ended September 30, 2022, gross transportation expense was $52.5 million or $5.84/boe, compared to $46.6 million or $6.14/boe in the same period of 2021.

The increase in gross transportation expense for the three and nine months ended September 30, 2022 of $2.0 million and $5.9 million, respectively, was due to higher overall volumes. This was partially offset by a decrease in per unit fees of $0.88/boe and $0.30/boe, caused by lower take-or-pay charges for the three and nine months ended September 30, 2022, respectively. Increased oil production allowed the Company to fulfill its oil firm service commitments. Additionally, the Company increased gas production and was able to secure permanent and temporary reassignments for a portion of its unused gas firm service commitments.

Risk Management Contracts

The Company continues to execute a consistent risk management program which is primarily designed to reduce revenue and cash flow volatility, help ensure there are sufficient cash flows to service debt obligations and fund a portion of the Company's capital program.

Risk management contract settlements are recognized as a realized gain or loss. The fair value of the Company's unsettled risk management contracts is recorded as an asset or liability at each reporting period with any change in the mark-to-market positions of the outstanding contracts recognized as an unrealized gain or loss in net profit (loss). Both realized and unrealized gains and losses on risk management contracts vary based on fluctuations related to the specific terms of outstanding contracts in the period including contract types, contract quantities and the underlying commodity reference prices.

The following table summarizes the liability position of risk management contracts outstanding:

(Cdn$ thousands)	**September 30, 2022**	December 31, 2021
Oil liability	**(2,421)**	(13,463)
NGL liability	**(16,976)**	(2,773)
Gas liability	**(2,254)**	(9,869)
Net fair value liability	**(21,651)**	(26,105)

The following table summarizes the realized losses on risk management contract settlements, as well as the unrealized losses or gains related to changes in the fair value of outstanding contracts:

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands)	**2022**	2021	% Change	**2022**	2021	% Change
Realized loss on risk management contracts [1]	**(28,307)**	(26,707)	6	**(93,575)**	(59,199)	58
Unrealized gain (loss) on risk management contracts [2]	**44,774**	(9,302)	(581)	**4,455**	(62,887)	(107)
Total gain (loss) on risk management contracts	**16,467**	(36,009)	(146)	**(89,120)**	(122,086)	(27)
(Cdn$ per boe)						
Realized loss on risk management contracts [1]	**(9.58)**	(11.73)	(18)	**(10.41)**	(7.79)	34
Unrealized gain (loss) on risk management contracts [2]	**15.16**	(4.08)	(471)	**0.50**	(8.28)	(106)
Total gain (loss) on risk management contracts	**5.58**	(15.81)	(135)	**(9.91)**	(16.07)	(38)

1 Represents actual cash settlements under the respective contracts.
2 Represents the change in fair value of contracts outstanding during the period.

During the three months ended September 30, 2022, the Company incurred realized losses on risk management contracts of $28.3 million, compared to realized losses of $26.7 million in the comparative period of 2021. The increased losses relate to improvements in strip pricing on gas contracts, relative to the underlying prices of the risk management contracts. This was partially offset by a lower volume of oil contracts which settled closer to strip pricing.

During the nine months ended September 30, 2022, the Company incurred realized losses on risk management contracts of $93.6 million, compared to realized losses of $59.2 million in the comparative period of 2021. The increased losses relate to improvements in strip pricing across all commodities relative to the underlying prices of the risk management contracts, with the largest impact incurred on the settlement of the Company's gas and oil contracts.

The unrealized gain on risk management contracts of $44.8 million for the three months ended September 30, 2022 is primarily due to the settlement of out-of-the money contracts throughout the quarter across all commodities and the deterioration of strip pricing on crude oil from June 30 to September 30, relative to the underlying prices of the risk management contract outstanding. The unrealized loss on risk management contracts of $9.3 million for the three months ended September 30, 2021 is primarily due to improvements in strip pricing across all commodities from June 30 to September 30, relative to the underlying prices of the risk management contracts outstanding. These pricing impacts were partially offset by the settlement of out-of-the money contracts throughout the quarter.

The unrealized gain on risk management contracts of $4.5 million for the nine months ended September 30, 2022 is primarily due to the settlement of out-of-the money contracts throughout the year on all commodities, partially offset by the improvements in strip pricing across all commodities from December 31 to September 30, relative to the underlying prices of the risk management contracts outstanding. The unrealized loss on risk management contracts of $62.9 million for the nine months ended September 30, 2021 is due to improvements in strip pricing across all commodities from December 31 to September 30, relative to the underlying prices of the risk management contracts outstanding.

As at September 30, 2022, the Company held the following outstanding risk management contracts:

Remaining Term	Reference	Total Daily Volume *(bbls/d)*	Weighted Average *(Price/bbls)*
Crude Oil Swaps			
Oct 1, 2022 – Dec 31, 2022	CDN$ WTI	1,000	72.95
Oct 1, 2022 – Dec 31, 2022	US$ WTI	4,100	81.16
Jan 1, 2023 – Jun 30, 2023	US$ WTI	1,000	87.00
Jan 1, 2023 – Dec 31, 2023	US$ WTI	1,100	65.00
NGL Swaps			
Oct 1, 2022 – Dec 31, 2022	CDN$ OPIS	1,000	27.50

Remaining Term	Reference	Total Daily Volume *(GJ/d)*	Total Daily Volume *(MMbtu/d)*	Weighted Average *(CDN$/GJ)*	Weighted Average *(US$/MMbtu)*
Natural Gas Swaps					
Apr 1, 2023 - Sept 30, 2023	CDN$ AECO	30,000	—	4.96	—
Oct 1, 2022 - Dec 31, 2022	US$ Dawn	—	30,000	—	3.50
Jan 1, 2023 - Jun 30, 2023	US$ Dawn	—	30,000	—	3.04
Natural Gas Collar					
Oct 1, 2022 – Dec 31, 2022	US$ NYMEX	—	55,000	—	5.00 - 14.50
Jan 1, 2023 - Dec 31, 2023	US$ NYMEX	—	30,000	—	5.00 - 9.80

Operating Netback

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands)	**2022**	2021	% Change	**2022**	2021	% Change
Revenue	**206,518**	103,047	100	**645,968**	300,660	115
Royalties	**(31,728)**	(10,053)	216	**(81,653)**	(24,066)	239
Operating expense	**(26,212)**	(21,116)	24	**(79,789)**	(61,319)	30
Net transportation expense	**(17,582)**	(15,555)	13	**(52,481)**	(46,455)	13
Operating netback, excluding realized losses on risk management contracts	**130,996**	56,323	133	**432,045**	168,820	156
Realized losses on risk management contracts	**(28,307)**	(26,707)	6	**(93,575)**	(59,199)	58
Operating netback [1]	**102,689**	29,616	247	**338,470**	109,621	209

(Cdn$ per boe)						
Revenue	**69.91**	45.25	54	**71.83**	39.59	81
Royalties	**(10.74)**	(4.41)	144	**(9.08)**	(3.17)	186
Operating expense	**(8.87)**	(9.27)	(4)	**(8.87)**	(8.07)	10
Net transportation expense	**(5.95)**	(6.83)	(13)	**(5.84)**	(6.12)	(5)
Operating netback, excluding realized losses on risk management contracts	**44.35**	24.74	79	**48.04**	22.23	116
Realized losses on risk management contracts	**(9.58)**	(11.73)	(18)	**(10.41)**	(7.79)	34
Operating netback [2]	**34.77**	13.01	167	**37.63**	14.44	161

1 Operating netback is a non-GAAP measure. Oil and gas revenue is the most directly comparable GAAP measure to operating netback. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

2 Operating netback per boe is a non-GAAP measure. Oil and gas revenue per boe is the most directly comparable GAAP measure to operating netback per boe. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

For the three months ended September 30, 2022, the Company's operating netback was $34.77/boe, an increase of $21.76/boe from the corresponding period of 2021. The increase was driven by improvements in commodity pricing which generated $24.66/boe of additional revenue and a $2.15/boe decrease in realized losses on risk management contracts. This was partially offset by a $6.33/boe increase in royalty expense.

For the nine months ended September 30, 2022, the Company's operating netback was $37.63/boe, an increase of $23.19/boe from the prior year. Improvements in commodity pricing generated $32.24/boe of additional revenue, which was partially offset by a $5.91/boe increase in royalty expense and a $2.62/boe increase in realized losses on risk management contracts.

General and Administrative ("G&A") Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change
Salaries and benefits	**4,310**	4,929	(13)	**14,267**	13,708	4
Information technology	**538**	533	1	**1,764**	1,621	9
Insurance	**449**	273	64	**1,364**	721	89
Professional fees [1]	**281**	291	(3)	**1,092**	997	10
Office rent	**175**	200	(13)	**504**	551	(9)
Other	**475**	319	49	**1,514**	870	74
Gross G&A expense	**6,228**	6,545	(5)	**20,505**	18,468	11
Capitalized G&A expense	**(1,347)**	(1,184)	14	**(3,780)**	(3,544)	7
Net G&A expense	**4,881**	5,361	(9)	**16,725**	14,924	12
Net G&A - $/boe	**1.65**	2.35	(30)	**1.86**	1.97	(5)

1 Professional fees include external audit, legal and reserve evaluation fees and other contract services.

Gross G&A expense was fairly consistent for both the three months ended September 30, 2022 and 2021. Salaries and benefits decreased in the current period, due to a one-time incentive program amendment recognized during the third quarter of 2021. This was offset with higher insurance costs from higher annual insurance rates in the third quarter of 2022 compared to 2021.

For the nine months ended September 30, 2022, gross G&A expense increased by $2.0 million or 11%, compared to the same period in 2021. The increase was primarily due to higher salaries and benefits, higher insurance premiums and increased other G&A expense. Higher salaries and benefits was due to the 2022 employee short term incentive program and a higher headcount compared to prior year. Increased insurance costs reflect higher rates under the annual corporate policy, and increased other G&A expense relates to a rise in travel, donations and corporate events as operations normalized with the lifting of COVID-19 restrictions during the current year.

Transaction Costs

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change
Transaction costs	**16,021**	—	100	**16,021**	—	100
Transaction costs - $/boe	**5.42**	—	100	**1.78**	—	100

On September 26, 2022, the Company announced that it had entered into a business combination agreement with DCRD, an affiliate of Riverstone Investment Group LLC, to form a publicly traded company listed on the NASDAQ. The transaction is expected to close before the end of the first quarter of 2023, subject to customary closing conditions, including the receipt of necessary regulatory approvals.

For the three and nine months ended September 30, 2022 the Company incurred $16.0 million in transaction costs related to the pending business combination with DCRD.

Share-based Compensation Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change
Gross share-based compensation expense	**1,441**	4,537	(68)	**12,668**	14,786	(14)
Capitalized share-based compensation expense	**(386)**	(1,123)	(66)	**(3,726)**	(3,504)	6
Net share-based compensation expense	**1,055**	3,414	(69)	**8,942**	11,282	(21)
Net share-based compensation expense - $/boe	**0.36**	1.50	(76)	**0.99**	1.49	(34)

Changes in gross share-based compensation expense relate to the number of units granted, the timing of grants, the fair value of units on the grant date, the vesting period over which the related expense is recognized and the timing and quantity of forfeitures.

Gross share-based compensation decreased by $3.1 million or 68% and $2.1 million or 14% for the three and nine months ended September 30, 2022, respectively, compared to the same periods of 2021. The decrease was primarily due to awards issued during 2021 which had accelerated vesting terms that fully vested by the second quarter of 2022.

Capitalized share-based compensation for the three months ended September 30, 2022 decreased by $0.7 million or 66%, compared to the same period of 2021, due to lower gross share-based compensation in 2022. Capitalized share-based compensation for the nine months ended September 30, 2022 increased by $0.2 million or 6%, compared to the same period of 2021, as a result of higher capital activity in 2022.

Finance Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change
Interest on 2020 Senior Notes - Cash	**1,785**	—	100	**1,785**	—	100
Interest on 2020 Senior Notes - PIK	**2,478**	3,774	(34)	**10,586**	10,853	(2)
Total interest on 2020 Senior Notes	**4,263**	3,774	13	**12,371**	10,853	14
Interest and fees on bank debt	**1,721**	927	86	**5,143**	4,892	5
Interest on lease obligation	**55**	40	38	**175**	142	23
Interest on EDC facility - letters of credit	**21**	60	(65)	**46**	60	(23)
Accretion of decommissioning liabilities	**161**	(22)	(832)	**415**	(67)	(719)
Total finance expense	**6,221**	4,779	30	**18,150**	15,880	14
Cash interest expense - $/boe	**1.21**	0.45	168	**0.79**	0.67	18
Non-cash interest and accretion expense - $/boe	**0.89**	1.65	(46)	**1.22**	1.42	(14)
Average principal debt outstanding during the period:						
Term debt - 2020 Senior Notes	**135,140**	128,722	5	**137,823**	124,265	11
Bank debt - credit facility	**57,180**	94,365	(39)	**85,537**	117,911	(27)
Total average principal debt outstanding	**192,320**	223,087	(14)	**223,360**	242,176	(8)

Finance expense is primarily comprised of interest incurred on the Company's outstanding 2020 Senior Notes (as defined herein) and credit facility borrowings (bank debt).

Senior Notes

The Company's 2020 Senior Notes bear interest at 12%, with the option of paying interest as cash or as paid-in-kind ("PIK"). During the three and nine months ended September 30, 2022, interest expense on the 2020 Senior Notes increased by $0.5 million or 13% and $1.5 million or 14%, respectively, compared to the same periods of 2021. The increase for both periods was due to a higher outstanding principal amount on which the interest is calculated, as a result of accrued PIK interest.

Bank Debt

During the three and nine months ended September 30, 2022, interest expense and fees on bank debt increased $0.8 million or 86%, and $0.3 million or 5% compared to the same periods of 2021. The increase for both periods was due to higher standby fees incurred as the borrowing base for the credit facility was raised to $300.0 million on June 9, 2022, compared to a borrowing base of $175.0 million as at September 30, 2021.

Loss on Foreign Exchange

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands)	**2022**	2021	% Change	**2022**	2021	% Change
Realized loss (gain) on foreign exchange	**2,040**	23	8,770	**2,257**	(18)	(12,639)
Unrealized loss on foreign exchange	**3,530**	3,513	—	**5,916**	289	1,947
Loss on foreign exchange	**5,570**	3,536	58	**8,173**	271	2,916

The Company's foreign exchange impacts primarily relate to the 2020 Senior Notes, which are denominated in US dollars and translated into Canadian dollars at the end of each reporting period.

During the three and nine months ended September 30, 2022, realized loss on foreign exchange increased $2.0 million or 8,770%, and $2.3 million or 12,639% compared to the same periods of 2021. The increase for both periods was due to the repayment of a portion of the 2020 Senior Notes which settled at a weaker exchange rate during the period. This was partially offset by a foreign exchange hedge entered into by the Company for the purpose of settling a portion of the 2020 Senior Notes.

Relative to the US dollar, the Canadian dollar weakened from 1.2886 at June 30, 2022 to 1.3707 at September 30, 2022. This resulted in a higher Canadian dollar liability for the 2020 Senior Notes and a corresponding unrealized foreign exchange loss of $3.5 million during the third quarter of 2022. Similarly, the Canadian dollar weakened from 1.2394 at June 30, 2021 to 1.2741 at September 30, 2021. This resulted in a higher Canadian dollar liability for the 2020 Senior Notes, and a corresponding unrealized foreign exchange loss of $3.5 million during the third quarter of 2021.

Relative to the US dollar, the Canadian dollar weakened from 1.2678 at December 31, 2021 to 1.3707 at September 30, 2022. This resulted in a higher Canadian dollar liability for the 2020 Senior Notes and a corresponding unrealized foreign exchange loss of $5.9 million for the nine months ended September 30, 2022. Similarly, the Canadian dollar weakened from 1.2732 at December 31, 2020 to 1.2741 at September 30, 2021. This resulted in a higher Canadian dollar liability for the 2020 Senior Notes, and a corresponding unrealized foreign exchange loss of $0.3 million for the nine months ended September 30, 2021.

Depletion and Depreciation Expense

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands, except per boe)	**2022**	2021	% Change	**2022**	2021	% Change
Depletion of developed and producing assets	**35,120**	27,714	27	**106,732**	92,389	16
Depreciation of corporate assets	**489**	118	314	**1,456**	1,017	43
Depreciation of right-of-use assets	**193**	183	5	**578**	551	5
Total depletion and depreciation expense	**35,802**	28,015	28	**108,766**	93,957	16
Depletion and depreciation expense - $/boe	**12.12**	12.30	(1)	**12.09**	12.37	(2)

Depletion and depreciation reflect the development costs of Hammerhead’s investments which are initially capitalized and then amortized to net income over the estimated useful lives of the assets. The Company's developed and producing assets are depleted using the unit-of-production method based on the estimated recoverable amount from total proved and probable ("2P") reserves. The depletion base consists of the historical net book value of capitalized costs plus estimated future development costs required to develop the Company's estimated 2P reserves. Depletion and depreciation rates are subject to change based on changes in the carrying value of the asset base, changes in future development costs, reserve updates and changes in production. Depletion expenses are calculated using depletion rates and production volumes applicable to each depletable asset.

During the three and nine months ended September 30, 2022, depletion, depreciation and impairment expense increased $7.8 million or 28%, and $14.8 million or 16%, respectively, compared to the same periods of 2021. The increase for both periods related to higher depletion of developed and producing assets, driven by higher production volumes. This was partially offset by a lower depletion rate, caused by a reduction in future development costs.

Loss (Gain) on Warrant Revaluation

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands)	**2022**	2021	% Change	**2022**	2021	% Change
Loss (gain) on warrant revaluation	**10,824**	(23)	(47,161)	**10,688**	90	11,776

The warrant liability was recorded at fair value upon inception and must be reassessed at the end of each period, with changes in the estimated fair value recognized through income as a non-cash item. During the three and nine months ended September 30, 2022, the Company incurred a loss on warrant revaluation of $10.8 million and $10.7 million respectively, compared to a nominal gain on warrant revaluation and a nominal loss on warrant revaluation for the same periods of 2021. The increased losses for both periods relate to an increase in the value of warrants outstanding due to a rise in the Company's share price during the third quarter of 2022.

Funds from Operations

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands)	2022	2021	% Change	2022	2021	% Change
Operating netback [1]	102,689	29,616	247	338,470	109,621	209
G&A expense	(4,881)	(5,361)	(9)	(16,725)	(14,924)	12
Optimization fees	—	(852)	(100)	—	(6,043)	(100)
Transaction costs	(16,021)	—	100	(16,021)	—	100
Cash interest expense	(3,582)	(1,027)	249	(7,149)	(5,094)	40
Realized foreign exchange gain (loss)	(2,040)	(23)	8,770	(2,257)	18	(12,639)
Other cash impacts [2]	380	301	27	2,560	567	352
Funds from operations [3]	76,545	22,654	238	298,878	84,145	255
(Cdn$ per boe)						
Operating netback [4]	34.77	13.01	167	37.63	14.44	161
G&A expense	(1.65)	(2.35)	(30)	(1.86)	(1.97)	(6)
Optimization fees	—	(0.38)	(100)	—	(0.79)	(100)
Transaction costs	(5.42)	—	100	(1.78)	—	100
Cash interest expense	(1.21)	(0.45)	169	(0.79)	(0.67)	18
Realized foreign exchange gain (loss)	(0.69)	(0.01)	6,800	(0.25)	—	100
Other cash impacts [2]	0.13	0.13	—	0.28	0.07	300
Funds from operations [5]	25.93	9.95	161	33.23	11.08	200
Weighted average common shares outstanding *(000s)*						
Basic	392,309	391,113	—	391,549	391,102	—
Diluted	967,757	391,113	147	957,324	391,102	145
Per common share - basic [6]	0.20	0.06		0.76	0.22	
Per common share - diluted [7]	0.08	0.06		0.31	0.22	

1 Operating netback is a non-GAAP measure. Oil and gas revenue is the most directly comparable GAAP measure to operating netback. Oil and gas revenue for the three months ended September 30, 2022 and 2021 were $206.5 million and $103.0 million, respectively. Oil and gas revenue for the nine months ended September 30, 2022 and 2021 were $646.0 million and $300.7 million, respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

2 Other cash impacts consist of treating and processing income, the Company's recoveries related to royalty interest and bad debt allowances.

3 Funds from operations is a non-GAAP measure. Net cash from operating activities is the most directly comparable GAAP measure for funds from operations. Net cash from operating activities for the three months ended September 30, 2022 and 2021 was $95.1 million and $25.5 million, respectively. Net cash from operating activities for the nine months ended September 30, 2022 and 2021 was $295.2 million and $87.6 million, respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

4 Operating netback per boe is a non-GAAP measure. Oil and gas revenue per boe is the most directly comparable GAAP measure to operating netback per boe. Oil and gas revenue for the three months ended September 30, 2022 and 2021 were $69.91/boe and $45.25/boe, respectively. Oil and gas revenue per boe for the nine months ended September 30, 2022 and 2021 were $71.83/boe and $39.59/boe, respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

5 Funds from operations per boe is a non-GAAP measure. Net cash from operating activities per boe is the most directly comparable GAAP measure for funds from operations per boe. Net cash from operating activities per boe for the three months ended September 30, 2022 and 2021 was $32.20/boe and $11.19/boe, respectively. Net cash from operating activities for the nine months ended September 30, 2022 and 2021 was $32.83/boe and $11.53/boe, respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

6 Funds from operations per common share - basic is a non-GAAP measure. Net cash from operating activities per common share - basic is the most directly comparable GAAP measure for funds from operations per common share - basic. Net cash from operating activities per common share - basic for the three months ended September 30, 2022 and 2021 was $0.24 and $0.07, respectively. Net cash from operating activities per common share - basic for the nine months ended September 30, 2022 and 2021 was $0.75 and $0.22, respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

7 Funds from operations per common share - diluted is a non-GAAP measure. Net cash from operating activities per common share - diluted is the most directly comparable GAAP measure for funds from operations per common share - diluted. Net cash from operating activities per common share - diluted for the three months ended September 30, 2022 and 2021 was $0.10 and $0.07, respectively. Net cash from operating activities per common share - diluted for the nine months ended September 30, 2022 and 2021 was $0.31 and $0.22, respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

The Company generated funds from operations of $76.5 million during the third quarter of 2022, a $53.9 million or 238% increase from the same quarter of 2021. The increase is primarily due to a $73.1 million increase in operating netback, partially offset by a $16.0 million increase in transaction costs, coupled with a $2.6 million increase in cash interest expense and a $2.0 million increase in realized foreign exchange loss from the repayment of the 2020 Senior Notes.

The Company generated funds from operations of $298.9 million during the nine months ended September 30, 2022, a $214.7 million or 255% increase from the same period of 2021. The increase is primarily due to a $228.8 million increase in operating netback, a $6.0 million decrease in optimization fees and a $2.0 million increase in other cash impacts. This was offset with a $16.0 million increase in transaction costs, a $2.3 million increase in realized foreign exchange loss and a $2.1 million increase cash interest expense related to the repayment of the 2020 Senior Notes, as well as a $1.8 million increase in G&A expense.

Net Profit (Loss)

	Three Months Ended September 30,			Nine Months Ended September 30,		
(Cdn$ thousands, except per share)	**2022**	2021	% Change	**2022**	2021	% Change
Net profit (loss)	**67,251**	(25,319)	(366)	**157,802**	(108,960)	(245)
Net profit (loss) attributable to ordinary equity holders - basic	**60,782**	(30,903)	(297)	**139,281**	(124,945)	(211)
Weighted average common shares outstanding - basic *(000s)*	**392,309**	391,113	—	**391,549**	391,102	—
Per common share - basic	**0.15**	(0.08)		**0.36**	(0.32)	
Net profit (loss) attributable to ordinary equity holders - diluted	**60,782**	(30,903)	(297)	**139,281**	(124,945)	(211)
Weighted average common shares outstanding - diluted *(000s)*	**967,757**	391,113	147	**957,324**	391,102	145
Per common share – diluted	**0.06**	(0.08)		**0.15**	(0.32)	

(Cdn$ thousands)	
Net loss, three months ended September 30, 2021	(25,319)
Increase from funds from operations [1]	**59,059**
Add (deduct) change in non-cash items:	
Increase in unrealized gain on risk management contracts	**54,076**
Increase in depletion, depreciation and impairment expense	**(7,787)**
Change in fair value of warrants	**(10,847)**
Other	**(1,931)**
Net profit, three months ended September 30, 2022	**67,251**

1 Funds from operations is a non-GAAP measure. Net cash from operating activities is the most directly comparable GAAP measure for funds from operations. Net cash from operating activities for the three months ended September 30, 2022 and 2021 was $95.1 million and $25.5 million, respectively, an increase of $69.6 million. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

The Company reported a net profit of $67.3 million for the three months ended September 30, 2022, compared to a net loss of $25.3 million in the same period of 2021. The $92.6 million improvement was primarily due to a $59.1 million increase in funds from operations and a $54.1 million increase in unrealized gain on risk management contracts. This was partially offset by all remaining non-cash impacts of $20.6 million as outlined in the table above.

(Cdn$ thousands)	
Net loss, nine months ended September 30, 2021	(108,960)
Increase from funds from operations [1]	**219,902**
Add (deduct) change in non-cash items:	
Increase in unrealized gain on risk management contracts	**67,342**
Loss on property disposition	**13,813**
Increase in depletion, depreciation and impairment expense	**(14,809)**
Increase in unrealized loss on foreign exchange	**(5,627)**
Change in fair value of warrants	**(10,598)**
Other	**(3,261)**
Net profit, nine months ended September 30, 2022	**157,802**

1 Funds from operations is a non-GAAP measure. Net cash from operating activities is the most directly comparable GAAP measure for funds from operations. Net cash from operating activities for the nine months ended September 30, 2022 and 2021 was $295.2 million and $87.6 million, respectively, an increase of $207.7 million. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

The Company reported a net profit of $157.8 million for the nine months ended September 30, 2022, compared to a net loss of $109.0 million in the same period of 2021. The $266.8 million improvement was primarily due to a $219.9 million increase in funds from operations and a $67.3 million increase in unrealized gain on risk management contracts. This was partially offset by the remaining non-cash impacts of $20.4 million as outlined in the table above.

Capital Expenditures

	Three Months Ended September 30, 2022			Nine Months Ended September 30,		
(Cdn$ thousands)	**2022**	2021	% Change	**2022**	2021	% Change
Drilling and completion	**39,719**	29,820	33	**121,085**	49,745	143
Equipment, facilities and pipelines	**31,453**	7,356	328	**71,451**	13,273	438
Workovers and maintenance capital	**3,308**	1,036	219	**11,327**	2,532	347
Land	**996**	—	100	**1,311**	—	100
Geological & geophysical	**29**	—	100	**163**	1	16,200
Other [1]	**1,827**	1,394	31	**4,870**	4,608	6
Capital expenditures [2]	**77,332**	39,606	95	**210,207**	70,159	200

1 Other includes capitalized salaries and benefits and corporate capital expenditures.

2 Net cash used in investing activities is the most directly comparable GAAP measure for capital expenditures, which is a non-GAAP measure. Net cash used in investing activities for the three months ended September 30, 2022 and 2021 was $58.7 million and $20.8 million, respectively. Net cash used in investing activities for the nine months ended September 30, 2022 and 2021 was $222.6 million and $49.0 million, respectively. Refer to the subsection "Other Advisories - Non-GAAP and Other Specified Financial Measures".

Capital expenditures for the three months ended September 30, 2022 were $77.3 million, up $37.7 million from the comparative period of 2021.

For the three months ended September 30, 2022, the Company incurred approximately $60.8 million in its Karr area, over half of which related to drilling a nine gross (nine net) well pad and one development well that the Company holds a 35% working interest in. The majority of the remaining funds incurred in Karr related to facility and pipeline expansion projects, with minor costs incurred on workover and maintenance capital. The Company also spent approximately $6.7 million in its Gold Creek area, primarily related to the construction, drill and tie-in activity of a three gross (three net) well pad.

For the three months ended September 30, 2021, the Company focused capital spending in its Gold Creek area where it incurred approximately $35.6 million in capital expenditures primarily related to construct, drill, complete and tie-in a six gross (six net) well pad and preliminary drilling and tie-in activities of two gross (two net) development wells and two gross (two net) water wells.

Capital expenditures for the nine months ended September 30, 2022 were $210.2 million, up $140.0 million from the comparative period of 2021.

For the nine months ended September 30, 2022, the Company incurred approximately $117.0 million in its Karr area. Over half of these expenditures related to the drill, completion and tie-in of a four gross (four net) well pad, which came on-stream in April of 2022, the drill and tie-in activity of a nine gross (nine net) well pad, and the preliminary drilling activity on one gross (0.35 net) development well. The remaining spend in the Karr area related to facility and pipeline expansion projects, as well as minor costs on workover and maintenance capital. The Company also incurred approximately $67.6 million in its Gold Creek area, primarily related to the drill, completion and tie-in of a five gross (five net) well pad which came on-stream in May of 2022, the drill, completion and tie-in of a four gross (four net) well pad which came on-stream in March of 2022 and the initial costs to construct, drill and tie-in one gross (one net) development well.

For the nine months ended September 30, 2021 the Company incurred approximately $39.4 million in its Gold Creek area, the majority of which related to the construction, drill, completion and tie-in of a six gross (six net) well pad and to initiate drilling and tie-in activities of two gross (two net) development wells and two gross (two net) water wells. In addition, the Company incurred approximately $21.8 million in its Karr area, mostly related to the completion and tie-in of four gross (3.5 net) development wells.

Net Well Information

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Number of wells) [1]	**2022**	2021	**2022**	2021
Spud	**12.00**	8.00	**22.00**	9.00
Rig released	**8.35**	7.00	**19.35**	7.00
Completed	**—**	1.00	**14.00**	3.50
Wells brought on-stream [2]	**—**	—	**22.00**	8.85

1 Well counts include development Montney and Duvernay wells.
2 On-stream dates are based on the first production date after the well is tied-in to the permanent well site facilities. Wells brought on-stream may include wells drilled and/or completed in a prior period.

As at September 30, 2022, the Company had 146.0 gross (143.3 net) Montney wells and one gross (one net) Duvernay well capable of producing. As at September 30, 2021, the Company had 119.0 gross (116.3 net) Montney wells and one gross (one net) Duvernay well capable of producing.

Land Acreage

	September 30, 2022			December 31, 2021		
	Gross acres	**Net acres**	**Working interest percentage**	Gross acres	Net acres	Working interest percentage
Montney	**119,840**	**107,664**	**90**	126,738	113,730	90
Duvernay	**7,858**	**6,610**	**84**	25,476	23,908	94

Capital Resources and Liquidity

Capital Resources

Bank Debt

(Cdn$ thousands)	**September 30, 2022**	December 31, 2021
Syndicated facility	**107,800**	106,300
Operating facility	**—**	—
Total bank debt outstanding	**107,800**	106,300

The Company's bank debt is held in a credit facility with a syndicate of lenders. On June 9, 2022, the Company amended its existing credit facility. Under the amended credit facility agreement, the aggregate principal borrowing base was increased to $300.0 million, consisting of a $280.0 million revolving syndicated facility and a $20.0 million operating facility. The amended credit facility agreement has a term date of May 31, 2023 and a maturity date of May 31, 2024, with an option to extend for an additional 364 days at the lenders' discretion. The total outstanding balance is due on the maturity date.

Under the amended credit facility, determination of the borrowing base is made by the lenders at their sole discretion, and is subject to re-determinations semi-annually as of May 31st and November 30th of the respective year.

As at September 30, 2022, Hammerhead was compliant with all covenants and cross default clauses stated in the amended credit facility agreement. Covenants include reporting requirements and limitations on excess cash, indebtedness, equity issuances, acquisitions, dispositions, hedging, encumbrances, asset retirement obligations, as well as other standard business operating covenants. The Company is not subject to financial covenants. The lenders have first lien on all of the Company's assets.

Amounts borrowed under the amended credit facility bear interest at the Company's option based on the referenced Canadian prime lending rate or the bankers' acceptance rate in effect, plus an applicable margin or fee, respectively. The applicable margin or fee is determined by the ratio of first lien indebtedness to earnings before interest, taxes, depreciation, depletion and amortization. The amended credit facility also includes standby fees on balances not drawn.

The following are the applicable prime margin and bankers' acceptance fee:

	Margin on Canadian Prime Rate	**Bankers' Acceptance Fee**	**Standby Fee**
Credit facility	1.75% - 5.25%	2.75% - 6.25%	0.69% - 1.56%

Term Debt

(Cdn$ thousands)	**September 30, 2022**	December 31, 2021
2020 Senior Notes – outstanding principal	**120,648**	120,648
Principal repayment, net of outstanding PIK interest [1]	**(44,661)**	23,374
Foreign exchange revaluation [2]	**1,627**	(9,275)
Total carrying value of long-term debt	**77,614**	134,747

1 The Company repaid $78.6 million of principal on its 2020 Senior Notes. The repayment is netted with the accumulated PIK interest of $32.1 million. Total accrued unpaid PIK as at September 30, 2022 is $1.8 million.

2 The 2020 Senior Notes are issued in US dollars and are revalued to Canadian dollars at each reporting period, using the period end foreign exchange rate.

The 2020 senior notes agreement ("the 2020 Senior Notes") has a maturity date of July 10, 2024. The notes bear interest at 12% per annum and provide the option of paying interest as cash or as paid-in-kind ("PIK"). PIK interest is added to the principal balance of the 2020 Senior Notes and is due on maturity.

On September 26, 2022, the Company repaid, at par value, US$59.3 million of principal and accrued interest on its 2020 Senior Notes, reducing the aggregate principal balance outstanding down to US$56.5 million.

The debt repayment was accounted for in accordance with IFRS 9 Financial Instruments, with the transaction costs of $0.2 million related to the settlement recognized as part of the loss on debt repayment. The following table summarizes the calculation of the loss on repayment of the 2020 Senior Notes:

(Cdn$ thousands)	
Net carrying amount of 2020 Senior Notes, prior to repayment	**78,621**
Less principal repaid	**(78,621)**
Transaction costs incurred	**(218)**
Loss on debt repayment	**(218)**

On settlement of US$57.9 million of principal, $5.2 million of the accumulated unrealized loss recognized for the nine months ended September 30, 2022, was reclassed to realized foreign exchange loss on the statement of profit (loss). The realized foreign exchange loss on debt was offset with a $3.2 million realized foreign exchange gain from the settlement of a foreign currency hedge entered into during the three months ended September 30, 2022.

As at September 30, 2022, the Company was in compliance with all covenants related to the 2020 Senior Notes.

Export Development Canada ("EDC") Letters of Credit

The Company has guaranteed letters of credit in both Canadian and US dollars. As at September 30, 2022 and December 31, 2021, the Company's Canadian dollar denominated letters of credit were guaranteed through EDC and totaled $13.8 million. The Company's US dollar denominated letters of credit were previously guaranteed by the operating facility, but were transferred to EDC on August 17, 2021. As at September 30, 2022, the Company's US dollar denominated guaranteed letters of credit, translated into Canadian dollars, totaled $1.0 million (December 31, 2021 - $0.9 million).

June 2020 Equity Commitment

On June 17, 2020, the Company entered into an investment agreement (the “June 2020 Investment Agreement”) with an affiliate of its controlling shareholder. Under the June 2020 Investment Agreement, the Company agreed to issue up to 600.0 million Series IX first preferred shares and 33.7 million common share purchase warrants, in exchange for aggregate cash proceeds of up to $300.0 million.

On February 5, 2021 the Company received an additional equity investment of $33.7 million cash proceeds in exchange for the issuance of 67.4 million Series IX first preferred shares. As at September 30, 2022, the remaining equity commitment under the June 2020 Investment Agreement was $166.3 million. Future draws are subject to approval of the controlling shareholder and satisfaction of terms and conditions, at any time prior to June 17, 2024.

December 2020 Equity Commitment

On December 8, 2020, the Company entered into an investment agreement (the “December 2020 Investment Agreement”) with an affiliate of one of its shareholders ("the Investor"). Under the December 2020 Investment Agreement, the Company agreed to issue up to 23.1 million Series IX first preferred shares and 1.3 million common share purchase warrants, in exchange for aggregate cash proceeds of up to $11.6 million.

On February 5, 2021 the Company received an additional equity investment of $1.3 million cash proceeds in exchange for the issuance of 2.6 million Series IX first preferred shares. As at September 30, 2022, the remaining equity commitment under the December 2020 Investment Agreement was $6.4 million. The Investor may be required to invest all or a portion of the remaining equity commitment at any time prior to June 17, 2024, subject to further investment made by an affiliate of the controlling shareholder under the June 2020 Investment Agreement.

Liquidity

Capital Management and Liquidity

Hammerhead’s objective when managing capital is to maintain a flexible capital structure and sufficient liquidity to meet its financial obligations and to execute its business plans. The Company considers its capital structure to include shareholders’ equity, the funds available under outstanding debt agreements, funds from operations and working capital. Modifications to Hammerhead’s capital structure can be accomplished through issuing common and preferred shares, issuing new debt, adjusting capital spending and acquiring or disposing of assets, though there is no certainty that any of these additional sources of capital would be available if required.

Working Capital Deficit and Available Funding

Working capital provides useful information by highlighting net assets that are expected to be realized, or net liabilities that are expected to be settled, within the current operating cycle. Available funding allows management and other users to evaluate the Company’s short term liquidity, and its capital resources available at a point in time. Available funding is not a standardized financial measure under IFRS and therefore may not be comparable with the calculation of similar measures disclosed by other entities.

(Cdn$ thousands)	September 30, 2022	December 31, 2021
Current assets	81,692	64,712
Current liabilities	(142,190)	(141,240)
Working capital deficit	(60,498)	(76,528)
Debt capacity	192,200	68,700
Equity commitment [1]	172,700	172,700
Available funding [2]	304,402	164,872

1 See Capital Resources section within this MD&A for a breakdown of the remaining equity commitment under the June and December 2020 Investment Agreements.

2 Available funding is a non-GAAP measure. Working capital deficit is the most directly comparable GAAP measure for available funding. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

Net Debt, Annualized Quarterly Adjusted EBITDA and Net Debt to Annualized Quarterly Adjusted EBITDA

Annualized quarterly adjusted EBITDA indicates the Company's ability to generate funds from its asset base on a continuing basis, for future development of its capital program and settlement of financial obligations. Hammerhead's short-term capital management objective is to fund its capital expenditures using primarily funds from operations, noting value-creating activities may be financed with a combination of funds from operations and other sources of capital. Net debt is used to assess and monitor liquidity at a point in time, while net debt to annualized quarterly adjusted EBITDA assists the Company in monitoring its capital structure and financing requirements. Net debt, annualized quarterly adjusted EBITDA and net debt to annualized quarterly adjusted EBITDA are not standardized measures under IFRS and therefore may not be comparable with the calculation of similar measures disclosed by other entities.

(Cdn$ thousands)	September 30, 2022	December 31, 2021
Bank debt	107,800	106,300
Term debt	77,614	134,747
Working capital deficit	60,498	76,528
Total net debt [1]	245,912	317,575
Annualized quarterly adjusted EBITDA [2]	391,232	180,048
Net debt to annualized quarterly adjusted EBITDA [3]	0.6	1.8

1 Net debt is a non-GAAP measure. The Company's third party debt obligations of the bank debt and the term debt are the most directly comparable GAAP measures for net debt. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

2 Annualized quarterly adjusted EBITDA is a non-GAAP measure. Net profit (loss) before income tax is the most directly comparable GAAP measure to annualized quarterly adjusted EBITDA. For the three months ended September 30, 2022 and December 31, 2021, the net profit (loss) was $67.3 million and $37.1 million, respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

3 Net debt to annualized quarterly adjusted EBITDA is a non-GAAP measure, derived from the net debt non-GAAP measure and annualized quarterly adjusted EBITDA non-GAAP measure, where the directly comparable GAAP measures are the Company's debt obligations of bank debt and term debt, and the Company's net profit (loss), respectively. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

Contractual Obligations and Commitments

At September 30, 2022, the Company is committed to future payments under the following agreements:

(Cdn$ thousands)	Year 1	Year 2	Year 3	Year 4	Year 5	Thereafter	Total
Firm transportation & processing	98,960	101,075	89,405	76,285	57,766	195,465	618,956
Office buildings [1]	912	825	763	763	763	191	4,217
Drilling services	1,392	—	—	—	—	—	1,392
Total annual commitments	101,264	101,900	90,168	77,048	58,529	195,656	624,565

1 Relates to non-lease components and non-indexed variable payments.

Supplemental Information
Financial – Quarterly extracted information

(Cdn$ thousands, except per share amounts, production and unit prices)	Q3 2022	Q2 2022	Q1 2022	Q4 2021	Q3 2021	Q2 2021	Q1 2021	Q4 2020
OPERATING								
Production volumes								
Crude oil (bbls/d)	9,279	10,025	9,874	7,135	5,854	7,317	6,968	7,177
Natural gas (Mcf/d)	111,353	116,667	113,703	101,028	95,304	104,784	109,122	114,330
Natural gas liquids (bbls/d)	4,273	4,397	4,030	3,787	3,014	3,864	4,967	4,192
Total (boe/d)	32,111	33,867	32,854	27,760	24,752	28,645	30,122	30,424
Liquids weighting %	42	43	42	39	36	39	40	37
Oil and gas revenue ($/boe)	69.91	81.09	64.10	54.50	45.25	38.96	35.43	27.59
Operating netback ($/boe) [1]	34.77	41.75	36.22	20.22	13.01	14.19	15.86	15.97
Oil and gas sales revenue	206,518	249,908	189,542	139,183	103,047	101,551	96,062	77,210
Operating netback [2]	102,689	128,673	107,108	51,653	29,617	36,986	43,018	44,683
Net cash from operating activities	95,138	129,623	70,463	33,540	25,492	31,701	29,851	34,114
Per common share – basic	0.24	0.33	0.18	0.09	0.07	0.08	0.08	0.09
Per common share – diluted	0.10	0.13	0.18	0.03	0.07	0.08	0.08	0.04
Funds from operations [3]	76,545	121,585	100,748	30,309	22,654	28,854	32,636	32,986
Per common share – basic [4]	0.20	0.31	0.26	0.08	0.06	0.07	0.08	0.08
Per common share – diluted [4]	0.08	0.12	0.26	0.03	0.06	0.07	0.08	0.04
Net profit (loss)	67,251	96,993	(6,442)	37,139	(25,319)	(50,016)	(33,625)	22,600
Net profit (loss) attributable to ordinary equity holders	60,782	90,825	(6,442)	31,344	(30,903)	(55,340)	(33,625)	17,599
Per common share – basic	0.15	0.23	(0.02)	0.08	(0.08)	(0.14)	(0.09)	0.05
Per common share – diluted	0.06	0.09	(0.02)	0.03	(0.08)	(0.14)	(0.09)	0.02
Net cash used in investing activities	58,669	68,414	95,514	42,190	20,809	6,731	21,450	9,182
Capital expenditures [5]	77,332	50,387	82,488	68,385	39,606	11,370	19,183	21,558
Weighted average common shares outstanding								
Basic	392,309	391,179	391,148	391,117	391,113	391,113	391,080	391,038
Diluted	967,757	975,668	391,148	952,281	391,113	391,113	391,080	842,536
FINANCIAL								
Working capital deficit	60,498	67,141	91,261	76,528	91,800	63,522	165,444	189,639
Available funding [6]	304,402	340,759	132,139	164,872	165,100	184,492	38,157	34,151
Net debt [7]	245,912	277,116	352,340	317,575	314,167	286,594	287,947	310,074

1 Operating netback per boe is a non-GAAP measure. Oil and gas revenue per boe is the most directly comparable GAAP measure to operating netback per boe. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

2 Operating netback is a non-GAAP measure. Oil and gas revenue is the most directly comparable GAAP measure to operating netback. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

3 Funds from operations is a non-GAAP measure. Net cash from operating activities is the most directly comparable GAAP measure to funds from operations. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

4 Funds from operations per basic and diluted common share are non-GAAP measures. Net cash from operating activities per basic and diluted share are the most directly comparable GAAP measure to funds from operations per basic and diluted common share. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

5 Capital expenditures is a non-GAAP measure. Net cash used in investing activities is the most directly comparable GAAP measure to capital expenditures. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

6 Available funding is a non-GAAP measure. Working capital deficit is the most directly comparable GAAP measure to available funding. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

7 Net debt is a non-GAAP measure. The Company's third party debt obligations of the bank debt and the term debt are the most directly comparable GAAP measures for net debt. Refer to the subsection “Other Advisories - Non-GAAP and Other Specified Financial Measures”.

Disclosure Controls and Procedures

Disclosure controls and procedures (“DC&P”) seek to ensure that information to be disclosed by Hammerhead is accumulated and communicated to management, as appropriate, to allow timely decisions regarding required disclosures. As at September 30, 2022, the Chief Executive Officer and the Chief Financial Officer evaluated the effectiveness of the design and operation of the Company’s DC&P. Based on their evaluation, the Chief Executive Officer and Chief Financial Officer have concluded that the Company’s DC&P were effective as at September 30, 2022. All control systems by their nature can only provide reasonable, but not absolute, assurance that the objectives of the control system are met.

Internal Control over Financial Reporting and Officer Certifications

Internal control over financial reporting is a process designed to provide reasonable assurance that all the assets are safeguarded and transactions are appropriately authorized, and to facilitate the preparation of relevant, reliable and timely information. Due to inherent limitations, internal control over financial reporting may not prevent or detect all misstatements due to fraud or error. The control framework Hammerhead’s officers used to design and evaluate the Company’s internal controls over financial reporting is the Internal Control – Integrated Framework (2013) by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”). All control systems by their nature can only provide reasonable, but not absolute, assurance that the objectives of the control system are met.

Forward-Looking Statements

Certain statements contained in this MD&A constitute forward-looking statements or information (collectively "forward-looking statements") within the meaning of applicable securities legislation, including, but not limited to, management's assessment of future plans, operations and strategies including the focus of the Company's operations; the Company's strategy and objectives for its business and assets; the business combination with DCRD and the anticipated timing thereof; the Company's risk management program and the benefits to be derived therefrom; terms of the Company's risk management contracts; terms of the Company's credit facilities; terms of the June 2020 Investment Agreement and December 2020 Investment Agreement; the Company's objectives for managing capital, including the Company's short-term capital management objective; expected sources of funding for future capital expenditures; current commitments and working capital deficit; determination of the Company’s depletion and depreciation rates; the Company's contractual obligations; and other matters related to the foregoing. Forward-looking statements are typically identified by words such as "estimate", "anticipate", "expect", "may", "will", "project", "could", "plan", "intend", "should", "potential" and similar words suggesting future events or future performance or may be identified by reference to a future date.

With respect to forward-looking statements contained in this document, the Company has made assumptions regarding, among other things: availability of future acquisition opportunities; the Company's ability to obtain necessary approvals to complete the business combination; future capital expenditure levels; future oil and natural gas prices; future oil and natural gas production levels; future exchange rates and interest rates; ability to obtain equipment and services in a timely manner to carry out development activities; pipeline capacity; the impact of increasing competition; the ability to obtain financing on acceptable terms; the general stability of the economic and political environments in which the Company operates; the timely receipt of any required regulatory approvals; the ability of the Company to obtain qualified staff, equipment and services in a timely and cost efficient manner; that the Company will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Company's conduct and results of operations will be consistent with its expectations; that the Company will have the ability to develop its oil and gas properties in the manner currently contemplated; the estimates of the Company's reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects; future accounting standards to be adopted or amended and the expected impact on the Company; that the Company will have the ability to add production and reserves through development and exploitation activities; the impact (and duration thereof) that the COVID-19 pandemic will have on: (i) the demand for crude oil, NGL and natural gas; (ii) the supply chain, including the Company's ability to obtain the equipment and services it requires; and (iii) the Company's ability to produce, transport and/or sell its crude oil, NGL and natural gas; the risk that the Company may not be able to fund its capital expenditures using primarily funds from operations; and the risk that the Company may not maintain a flexible capital structure or sufficient liquidity to meet its financial obligations and to execute its business plans. Although the Company believes that the expectations reflected in the forward-looking statements contained in this document, and the assumptions on which such forward-looking statements are made, are reasonable, readers are cautioned not to place undue reliance on forward-looking statements included in this document, as there can be no assurance that the plans, intentions or expectations upon which the forward-looking statements are based will occur. Readers are cautioned that the foregoing list is not exhaustive of all assumptions which have been considered.

By their nature, forward-looking statements involve numerous known and unknown risks and uncertainties, which may cause the Company's actual performance and financial results in future periods to differ materially from any estimates or projections of future performance or results expressed or implied by such forward-looking statements. These risks and uncertainties include, among other things, the ability of management to execute its business plan; general economic and business conditions; that the Company may not receive all necessary approvals to complete the business combination; the risks of the oil and natural gas industry, such as operational risks in exploring for, developing and producing crude oil and natural gas and market demand; the possibility that government policies or laws may change or governmental approvals may be delayed or withheld; actions by governmental or regulatory authorities including production curtailment and increasing taxes and changing royalty regimes and other incentive programs relating to the oil and gas industry; access to pipeline capacity; unexpected downtime; risks and uncertainties involving geology of oil and natural gas deposits; unexpected drilling results; delays in anticipated timing of drilling and completion of wells; the Company's ability to enter into or renew leases; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to production (including decline rates), reserves, costs and expenses; the effect of the COVID-19 pandemic on the Company’s business, operations and financial condition; potential disruption of the Company's operations as a result of the COVID-19 pandemic through potential loss of manpower and labour pools resulting from, among other things, quarantines in the Company's operating areas; fluctuations in oil and natural gas prices, foreign currency exchange rates and interest rates; health, safety and environmental risks; risks associated with unexpected potential future law suits and regulatory actions against the Company; uncertainties as to the availability and cost of financing; inability to extend the Company's credit facility at each review on the current terms, on newly negotiated terms or at all; inability to access sufficient capital from internal and external sources; and the risks described under "Operational and Other Risk Factors" herein. Readers are cautioned that the foregoing list is not exhaustive of all possible risks and uncertainties.

The forward-looking statements contained in this document speak only as of the date of this document. Except as expressly required by applicable securities laws, the Company does not undertake any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise. The forward-looking statements contained in this document are expressly qualified by this cautionary statement.

Operational and Other Risk Factors

Hammerhead’s operations are conducted in the same business environment as most other Canadian oil and gas operators and the business risks are very similar. The business of exploring for, developing and producing oil and natural gas reserves is inherently risky. Significant risks are summarized in the 2021 Annual MD&A and, other than as set forth below, have remained unchanged during the first nine months of 2022. The following discussion summarizes new or modified risk factors in light of recent events and should be read in conjunction with the risk factors in the 2021 Annual MD&A. The risks set out below and in the 2021 Annual MD&A are not an exhaustive list, nor should they be taken as a complete summary or description of all the risks related to Company's business and operations.

- The Company is exposed to commodity price risk whereby the fair value of future cash flows will fluctuate as a result of changes in commodity prices. From time to time, the Company may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline. However, to the extent that the Company engages in price risk management activities to protect itself from commodity price declines, it may also be prevented from realizing the full benefits of price increases above the levels of the derivative instruments used to manage price risk. In addition, the Company's hedging arrangements may expose it to the risk of financial loss in certain circumstances, including instances in which: production falls short of the hedged volumes or prices fall significantly lower than projected, there is a widening of price-base differentials between delivery points for production and the delivery point assumed in the hedge arrangement, counterparties to the hedging arrangements or other price risk management contracts fail to perform under those arrangements, or a sudden unexpected event materially impacts oil and natural gas prices.

- The Company's operating costs could escalate and become uncompetitive due to supply chain disruptions, inflationary cost pressures, equipment limitations, escalating supply costs, commodity prices, and additional government intervention through stimulus spending or additional regulations, which could have a material adverse effect on its financial performance and cash flows. The cost or availability of oil and gas field equipment may adversely affect the Company's ability to undertake exploration, development and construction projects. The oil and gas industry is cyclical in nature and is prone to shortages of supply of equipment and services including drilling rigs, geological and geophysical services, engineering and construction services, major equipment items for infrastructure projects and construction materials generally. These materials and services may not be available when required at reasonable prices. A failure to secure the services and equipment necessary to the Company's operations for the expected price, on the expected timeline, or at all, may have an adverse effect on the Company's financial performance and cash flows.

Other Advisories

Oil and Gas

"BOEs" may be misleading, particularly if used in isolation. A BOE conversion ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent (6 mcf: 1 bbl) 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 the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.

This MD&A contains certain oil and gas metrics, including operating netback, which do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included herein to provide readers with additional measures to evaluate the Company's performance; however, such measures are not reliable indicators of the future performance of the Company and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon. Management uses these oil and gas metrics for its own performance measurements and to provide security holders with measures to compare the Company's operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this MD&A, should not be relied upon for investment or other purposes.

Non-GAAP and Other Specified Financial Measures

This MD&A includes certain meaningful performance measures commonly used in the oil and natural gas industry that are not defined under IFRS, as outlined below. These performance measures 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 consolidated financial statements. Readers are cautioned that these non-GAAP and capital management measures are not standardized financial measures under IFRS, and might not be comparable to similar financial measures disclosed by other entities. The non-GAAP and capital management measures used in this report are summarized as follows:

Non-GAAP Financial Measures

Capital Expenditures

Management uses capital expenditures to determine the amount of cash flow used for capital reinvestment. See the following table for the reconciliation of capital expenditures to net cash used in investing activities, the most directly comparable GAAP measure.

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Cdn$ thousands)	**2022**	2021	**2022**	2021
Net cash used in investing activities	**58,669**	20,809	**222,597**	48,990
Proceeds from asset disposition	**—**	—	**—**	10,027
Net change in accounts payable related to the addition of PP&E	**18,663**	18,797	**(12,390)**	11,142
Capital expenditures	**77,332**	39,606	**210,207**	70,159

Available Funding

The available funding measure allows management and other users to evaluate the Company’s short term liquidity, and its capital resources available at a point in time. Available funding is comprised of working capital, the undrawn component of Hammerhead’s Credit Facilities, plus the remaining equity commitment related to any outstanding investment agreements.

HHR's available funding is disclosed in the "Liquidity" section within this MD&A, which includes its most directly comparable GAAP measure, working capital.

Operating Netback

Operating netback is calculated by deducting royalties, operating expense, transportation expense, and realized (losses) gains from risk management contracts from oil and gas revenue. Management believes that operating netback is a key performance indicator to assess the profitability of the Company's developed and producing assets, and to provide investors with information that is also commonly presented by peers within the industry. HHR's netback is disclosed in the "Operating Netback" section within this MD&A, which includes its most directly comparable GAAP measure, oil and gas revenue.

Funds from Operations

Funds from operations is comprised of cash provided by operating activities, excluding the impact of changes in non-cash working capital and settlement of decommissioning obligations. Management believes excluding the changes in non-cash working capital provides a more meaningful performance measure of the Company's operations on an ongoing basis, as it removes the impact of changes in timing of collections and payments, which are variable. Decommissioning provision costs incurred also vary depending upon the Company's planned capital program and the maturity of operating areas requiring environmental remediation. Funds from operations as presented should not be considered an alternative to, or more meaningful than, cash flow from operating activities, net profits or other measures of financial performance calculated in accordance with IFRS.

The following table reconciles funds from operations to net cash from operating activities, which is the most directly comparable GAAP measure:

	Three Months Ended September 30,		Nine Months Ended September 30,	
(Cdn$ thousands)	**2022**	2021	**2022**	2021
Net cash from operating activities	**95,138**	25,492	**295,224**	87,571
Changes in non-cash working capital	**(13,425)**	(2,838)	**8,699**	(2,900)
Realized foreign exchange loss on debt repayment	**(5,168)**	—	**(5,168)**	—
Settlement of decommissioning obligations	**—**	—	**123**	—
Loss on settlement under long term retention program	**—**	—	**—**	(527)
Funds from operations	**76,545**	22,654	**298,878**	84,144

Non-GAAP Financial Ratios

Operating Netback per boe

Management calculates operating netback per boe as operating netback divided by the Company's total production. Operating netback is a non-GAAP financial measure component of operating netback per boe. Management believes this performance measure provides key information about the profitability of the Company's developed and producing assets, isolated for the impact of changes in production volumes. HHR's operating netback per boe is disclosed in the "Operating Netback" section within this MD&A.

Funds from Operations per boe and Funds from Operations per Basic Share and Diluted Share

Funds from operations per boe is calculated by dividing funds from operations by the Company's total production. Funds from operations per basic share and diluted share is calculated by dividing funds from operations by the Company's basic and diluted weighted average shares outstanding. Funds from operations is a non-GAAP financial measure component of funds from operations per boe, and funds from operations per basic share and diluted share.

Funds from operations per boe is utilized by management to assess the profitability of the Company's developed and producing assets and to compare current results to prior periods or to peers by isolating for the impact of changes in production volumes. Funds from operations per basic share and diluted share is utilized by Management to indicate the funds generated from the business that could be allocated to each shareholder's equity position. Funds from operations per boe and funds from operations per basic share and diluted share are disclosed in the "Funds from Operations" section within this MD&A.

Capital Management Measures

Adjusted EBITDA and Annualized Quarterly Adjusted EBITDA

Adjusted EBITDA is calculated as net profit (loss) before interest and financing expenses, income taxes, depletion, depreciation and amortization, adjusted for certain non-cash items, or other items that are not considered part of normal business operations. Annualized quarterly adjusted EBITDA is adjusted EBITDA for the quarter, multiplied by four. Adjusted EBITDA indicates the Company's ability to generate funds from its asset base on a continuing basis, for future development of its capital program and settlement of financial obligations.

Adjusted EBITDA as presented should not be considered an alternative to, or more meaningful than, net profit (loss) before income tax, or other measures of financial performance calculated in accordance with IFRS. The following is a reconciliation of adjusted EBITDA to the most directly comparable GAAP measure, net profit (loss) before income tax:

	Three Months Ended September 30,		
(Cdn$ thousands)	**2022**	2021	% Change
Net profit (loss) before income tax	**67,251**	(25,319)	(366)
Add (deduct):			
Unrealized (gain) loss on risk management contracts	**(44,774)**	9,302	(581)
Optimization fees	**—**	852	(100)
Transaction costs	**16,021**	—	100
Share-based compensation	**1,055**	3,414	(69)
Depletion and depreciation	**35,802**	28,015	28
Finance expense	**6,221**	4,779	30
Loss (gain) on foreign exchange	**5,570**	3,536	58
Loss on warrant liability	**10,824**	(23)	(47,161)
Loss on debt repayment	**218**	—	—
Other income, excluding transportation income	**(380)**	(300)	27
Adjusted EBITDA	**97,808**	24,256	303
Annualized quarterly adjusted EBITDA	**391,232**	97,024	303

Net Debt and Net Debt to Annualized Quarterly Adjusted EBITDA

Net debt is calculated as the outstanding balance on the Company’s credit facility, the 2020 Senior Notes and working capital. The 2020 Senior Notes are calculated as the principal amount outstanding, plus accrued PIK interest, converted to Canadian dollars at the closing exchange rate for the period. Net debt to annualized quarterly adjusted EBITDA is net debt divided by annualized quarterly adjusted EBITDA. Net debt is used to assess and monitor liquidity at a point in time, while net debt to annualized quarterly adjusted EBITDA assists the company in monitoring it's capital structure and financing requirements.

Net debt and net debt to annualized quarterly adjusted EBITDA are disclosed in the "Liquidity" section within this MD&A.

Abbreviations

The following is a list of abbreviations that may be used in this MD&A:

bbl	barrel	AECO	AECO "C" hub price index for Alberta natural gas
bbls/d	barrels per day	Crude oil	Light crude oil and medium crude oil as defined in National Instrument 51-101
boe	barrels of oil equivalent	Natural gas	Conventional natural gas as defined in National Instrument 51-101
boe/d	barrels of oil equivalent per day	GAAP	generally accepted accounting principles
Mcf	thousand cubic feet	G&A	general and administrative
Mcf/d	thousand cubic feet per day	WTI	West Texas Intermediate
MMbbl	million barrel	USD	U.S. dollars
MMmcf	million cubic feet	CAD	Canadian dollars
MMboe	million barrels of oil equivalent	US	United States
mmbtu	million British Thermal Units	CDN	Canadian
NGL	Natural gas liquids	RSUs	Restricted Share Units
GJ	gigajoule		

CORPORATE INFORMATION

BOARD OF DIRECTORS
Scott Sobie[2,4]
Bryan Begley[2,3]
Robert Tichio[3,4]
Stewart Hanlon[1,4]
Paul Charron[1,2,3]
Jesal Shah[1]

[1] Member of Audit Committee
[2] Member of Reserves Committee
[3] Member of Compensation Committee
[4] Member of Governance Committee

EXECUTIVES

Scott Sobie
President & Chief Executive Officer

Mike Kohut
Senior Vice President & Chief Financial Officer

Daniel Labelle
Senior Vice President of Development & A&D

David M. Anderson
Senior Vice President of Operations & Alternative Energy

Nicki Stevens
Senior Vice President of Production, Marketing & ESG

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