## Q3 2021 Management's Discussion and Analysis

The following management's discussion and analysis ("MD&A") as provided by the management of Headwater Exploration Inc. ("Headwater" or the "Company") is dated November 10, 2021 and should be read in conjunction with the unaudited interim condensed financial statements as at and for the three and nine months ended September 30, 2021, and the MD&A and the audited financial statements and the notes thereto for the year ended December 31, 2020, copies of which are available through the System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com. The unaudited interim condensed financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") and in accordance with IAS 34 *Interim Financial Reporting*. All dollar amounts are referenced in Canadian dollars unless otherwise stated.

## Description of the Company

Headwater is a Canadian junior resource company engaged in the exploration for and development and production of petroleum and natural gas in Canada. Headwater currently has heavy oil production in the Clearwater formation in the Marten Hills area of Alberta and natural gas production in the McCully field near Sussex, New Brunswick.

Unless otherwise indicated herein, all production information presented herein has been presented on a gross basis, which is the Company's working interest prior to deduction of royalties and without including any royalty interests.

### HIGHLIGHTS FOR THREE MONTHS ENDED SEPTEMBER 30, 2021

- Generated average production of 7,688 boe/d representing an increase of 17% over the second quarter of 2021 and an increase of 60% over the first quarter of 2021.

- Achieved adjusted funds flow from operations[(1)] of $31.5 million ($0.16 per share basic), representing an increase of 36% over the second quarter of 2021 and an increase of 118% over the first quarter of 2021. Cash flows from operating activities were $27.9 million in the third quarter of 2021.

- Achieved an operating netback of $46.17/boe and an adjusted funds flow netback of $45.01/boe.

- Achieved adjusted net income[(1)] of $28.9 million ($0.14 per share basic). The Company's net income, inclusive of the remeasurement loss on the warrant liability, was $26.1 million in the third quarter of 2021.

- Commissioned the Company's joint gas processing facility in the Marten Hills area which resulted in first sales gas and an approximate 50% reduction in CO2e emissions intensity from the first quarter of 2021.

- Executed a $37.3 million capital program in the Marten Hills area including 3 successful exploration wells and 16 multi-lateral development wells at a 100% success rate.

- As at September 30, 2021, Headwater had adjusted working capital[(1)] of $63.7 million and no outstanding debt. The Company's working capital, inclusive of financial derivatives and the warrant liability, was $16.5 million as at September 30, 2021.

(1) Non-IFRS measure. See "Non-IFRS Financial Measures" advisory.

## Results of Operations

## Production and Pricing

| | Three months ended September 30, 2021 | 2020 | Percent Change | Nine months ended September 30, 2021 | 2020 | Percent Change |
|---|---|---|---|---|---|---|
| Average daily production | | | | | | |
| Heavy oil (bbls/d) | 7,637 | - | 100 | 5,751 | - | 100 |
| Natural gas (mmcf/d) | 0.3 | - | 100 | 3.7 | 3.7 | - |
| Natural gas liquids (bbls/d) | - | - | - | 3 | 2 | 50 |
| Barrels of oil equivalent (boe/d) | 7,688 | - | 100 | 6,363 | 625 | 918 |
| Average daily sales (boe/d) (1) | | | | | | |
| Heavy oil (bbls/d) | 7,562 | - | 100 | 5,743 | - | 100 |
| Natural gas (mmcf/d) | 0.3 | - | 100 | 3.7 | 3.7 | - |
| Natural gas liquids (bbls/d) | - | - | - | 3 | 2 | 50 |
| Barrels of oil equivalent (boe/d) | 7,613 | - | 100 | 6,355 | 625 | 917 |
| Headwater average sales price (2) | | | | | | |
| Heavy oil ($/bbl) (3) | 70.00 | - | 100 | 65.15 | - | 100 |
| Natural gas ($/mcf) | 4.49 | - | 100 | 6.43 | 2.44 | 164 |
| Natural gas liquids ($/bbl) | - | - | - | 70.14 | 57.81 | 21 |
| Barrels of oil equivalent ($/boe) | 69.71 | - | 100 | 62.60 | 14.80 | 323 |
| Average Benchmark Price | | | | | | |
| WTI (US$/bbl) (4) | 70.56 | 40.93 | 72 | 64.82 | 38.32 | 69 |
| WCS differential to WTI (US$/bbl) | (13.58) | (9.09) | 49 | (12.51) | (13.69) | (9) |
| WCS (Cdn$/bbl) (5) | 71.81 | 42.41 | 69 | 65.41 | 32.98 | 98 |
| Condensate at Edmonton (Cdn$/bbl) | 86.78 | 49.78 | 74 | 80.23 | 46.71 | 72 |
| AGT (US$/mmbtu) (6) | - | - | - | 4.68 | 2.08 | 125 |
| AECO 5A (Cdn$/GJ) | 3.41 | 2.12 | 61 | 3.11 | 1.98 | 57 |
| NYMEX Henry Hub (US$/mmbtu) | 4.01 | 1.98 | 103 | 3.18 | 1.88 | 69 |
| Exchange rate (Cdn$/US$) | 1.26 | 1.33 | (5) | 1.25 | 1.35 | (7) |

(1) Includes sales of unblended heavy crude oil excluding the impact of purchased condensate. The Company's heavy oil sales volumes and production volumes differ due to changes in inventory.
(2) Average sales prices are calculated using average sales volumes.
(3) Realized heavy oil prices are based on sales, net of blending expense.
(4) WTI = West Texas Intermediate
(5) WCS = Western Canadian Select
(6) AGT = Algonquin city-gates. The AGT price is the average for the winter producing months in the McCully field which include January – April.

## Sales

| | Three months ended September 30, 2021 | 2020 | Percent Change | Nine months ended September 30, 2021 | 2020 | Percent Change |
|---|---|---|---|---|---|---|
| | *(thousands of dollars)* | | | *(thousands of dollars)* | | |
| Heavy oil, net of blending | 48,702 | - | 100 | 102,135 | - | 100 |
| Natural gas | 127 | - | 100 | 6,411 | 2,500 | 156 |
| Natural gas liquids | - | - | - | 62 | 37 | 68 |
| Total product sales, net of blending | 48,829 | - | 100 | 108,608 | 2,537 | 4181 |
| Gathering, processing and transportation | 12 | - | 100 | 784 | 336 | 133 |
| Total sales, net of blending | 48,841 | - | 100 | 109,392 | 2,873 | 3708 |

Marten Hills

The Company’s realized price received for its heavy crude oil is determined by the quality of crude compared to the benchmark price of WCS. Headwater’s heavy crude oil production (average 18 – 22˚ API) is blended with diluent in order to meet pipeline transportation specifications.

During the three months ended September 30, 2021, Headwater’s heavy oil sales volumes averaged 7,562 bbls/d and the Company recognized heavy oil sales net of blending expense of $48,702 thousand. The Company’s heavy oil realized price for the three months ended September 30, 2021 was $70.00/bbl, reflecting a discount to WCS of $1.81/bbl mainly resulting from apportionment and terminal outages.

During the nine months ended September 30, 2021, Headwater’s heavy oil sales volumes averaged 5,743 bbls/d and the Company recognized heavy oil sales net of blending expense of $102,135 thousand. The Company’s heavy oil realized price for the nine months ended September 30, 2021 was $65.15/bbl, reflecting a discount to WCS of $0.26/bbl. The decrease in discount to WCS realized over the nine months ended September 30, 2021 is a result of the Company selling more volumes later in the year at higher pricing.

The Company expects the annual weighted average discount to WCS to be approximately $2.00/bbl.

As a result of the commissioning of the Company’s joint gas processing facility during the third quarter of 2021, Headwater realized its first sales gas from the Marten Hills area. The transaction price is based on the AECO 5A daily benchmark price adjusted for heat content. Headwater’s natural gas sales volumes averaged 0.3 mmcf/d and its natural gas sales were $127 thousand during the three months ended September 30, 2021.

McCully

The Company sells its natural gas production daily from the McCully field in New Brunswick. The transaction price is based on the AGT daily benchmark price adjusted for the delivery location and heat content. No sales were recorded during the three months ended September 30, 2021 or in the corresponding period of 2020. The Company shut-in production effective May 1, 2021 and May 1, 2020 to take advantage of higher natural gas pricing during the winter months. The Company expects to resume operations in the middle of November 2021.

Natural gas sales for the nine months ended September 30, 2021, increased to $6,284 thousand from $2,500 thousand in the corresponding period of 2020, due primarily to a 166% increase in Headwater’s average realized natural gas sales price as production remained consistent over the periods at 3.6 mmcf/d during the nine months ended September 30, 2021 compared to 3.7 mmcf/d during the nine months ended September 30, 2020. The increase in Headwater’s average realized natural gas sales price was consistent with the increase in the AGT benchmark price over the period and was due to a surge in cold weather from the polar vortex experienced in late January into February, driving up natural gas demand in the Northeastern United States.

Headwater owns the midstream facilities which process and transport gas from the McCully field to the Maritimes & Northeast Pipeline. Gathering, processing and transportation revenue primarily relates to income earned on third party gas flowing through these facilities. This revenue will vary quarter over quarter depending on third party volumes processed.

## Gains (Losses) on Financial Derivatives

Headwater enters into financial derivative contracts to manage the risks associated with fluctuations in commodity prices and foreign exchange rates in order to secure future cash flows. The Company has entered into commodity contracts to fix pricing for the NYMEX, AGT Basis and AGT indices for its natural gas production with respect to its McCully assets. The Company has also entered into commodity contracts to fix pricing for the WCS Basis index for its heavy oil production with respect to its Marten Hills assets.

The table below summarizes realized and unrealized gains (losses) on financial derivative contracts:

| | Three months ended September 30, 2021 | 2020 | Percent Change | Nine months ended September 30, 2021 | 2020 | Percent Change |
|---|---|---|---|---|---|---|
| | *(thousands of dollars)* | | | *(thousands of dollars)* | | |
| Realized gains (losses) | - | - | - | (405) | 3,937 | (110) |
| Unrealized losses | (7,346) | (280) | 2524 | (9,058) | (1,612) | 462 |
| Financial derivative gains (losses) | (7,346) | (280) | 2524 | (9,463) | 2,325 | (507) |
| Realized gains (losses) per boe | - | - | - | (0.23) | 22.97 | (101) |
| Unrealized losses per boe | (10.49) | - | 100 | (5.22) | (9.41) | (45) |
| Per boe ($) | (10.49) | - | 100 | (5.45) | 13.56 | (140) |

The realized financial derivative gains and losses during the three and nine months ended September 30, 2021 represent the natural gas contracts referenced to the AGT price. A realized financial derivative loss was recorded during the nine months ended September 30, 2021 of $405 thousand compared to a realized gain of $3,937 thousand for the nine months ended September 30, 2020. The Company recognized losses on its natural gas contracts in 2021 as the commodity contracts to fix the AGT price were lower when compared to the AGT settlement price in the period. The below average temperatures from the polar vortex in February 2021 caused increased natural gas demand, driving up actual realized pricing above Headwater's fixed contract pricing.

For the three and nine months ended September 30, 2021, Headwater recognized unrealized losses of $7,346 thousand and $9,058 thousand, respectively, primarily reflecting the significant increase in forward pricing for NYMEX and AGT natural gas prices. As at September 30, 2021, the fair value of Headwater's outstanding financial derivative contracts was an unrealized liability of $9.0 million as reflected in the unaudited interim condensed financial statements. The fair value or mark to market value of these contracts is based upon the estimated amount that would have been payable as at September 30, 2021, had the contracts been monetized or terminated. Subsequent changes in the fair value of the contracts are recognized in each reporting period and could be materially different than what is recorded as at September 30, 2021.

Including the commodity contracts entered into subsequent to the end of the quarter, Headwater has hedged a total volume of 5,000 mmbtu/d at an average price of Cdn$13.40/mmbtu representing approximately 65% of the Company's total expected production for McCully for the 2021-2022 winter season.

As at September 30, 2021, Headwater had the following financial derivative commodity contracts outstanding:

| Commodity | Index | Type | Term | Daily Volume | Contract Price |
|---|---|---|---|---|---|
| Natural Gas | AGT (1) | Fixed | Nov 2021 | 2,500 mmbtu | Cdn$5.71/mmbtu |
| Natural Gas | AGT (1) | Fixed | Dec 2021 | 2,500 mmbtu | US$15.01/mmbtu (6) |
| Natural Gas | AGT Basis (1) (2) | Differential | Dec 1- Mar 31, 2022 | 2,500 mmbtu | Cdn$4.16/mmbtu |
| Natural Gas | AGT Basis (1) (3) | Differential | Jan 1- Feb 28, 2022 | 2,500 mmbtu | Cdn$7.26/mmbtu |
| Natural Gas | NYMEX (4) | Fixed | Dec 1- Mar 31, 2022 | 2,500 mmbtu | Cdn$3.76/mmbtu |
| Natural Gas | AGT (1) | Fixed | Mar 2022 | 2,500 mmbtu | US$8.93/mmbtu (6) |
| Natural Gas | NYMEX (4) | Fixed | Jan 1- Feb 28, 2022 | 2,500 mmbtu | Cdn$3.85/mmbtu |
| Crude Oil | WCS Basis (5) | Differential | Oct 1- Dec 31, 2021 | 2,000 bbls | US$13.16/bbl |

(1) AGT = Algonquin city-gates
(2) Headwater pays on AGT while counterparty pays on NYMEX plus Cdn$4.16/mmbtu
(3) Headwater pays on AGT while counterparty pays on NYMEX plus Cdn$7.26/mmbtu
(4) NYMEX = NYMEX Henry Hub
(5) WCS = Western Canadian Select. Headwater pays on WCS while counterparty pays on WTI (West Texas Intermediate) less USD$13.16/bbl
(6) Subsequent to September 30, 2021, AGT hedges converted to Cdn at a Cdn/US rate of 1.24

The Company is exposed to fluctuations of the Canadian to U.S. dollar exchange rate given realized pricing is directly influenced by U.S. dollar denominated benchmark pricing and from exposure to its U.S. dollar denominated heavy oil and natural gas marketing arrangements.

Headwater mitigates this risk by entering into commodity contracts in Canadian dollars and entering into short term foreign exchange contracts.

As at September 30, 2021, Headwater had the following financial derivative foreign exchange contract outstanding:

| Type | Buy Currency | Sell Currency | Rate | Notional Amount | Settlement Date |
|---|---|---|---|---|---|
| Forward contract | CAD | USD | WMR noon rate, September 2021 average (1) | US$16,300,000 | October 25, 2021 |

(1) WM/Reuters Intraday Spot Rate as of Noon EST

## Royalty Expense

| | Three months ended September 30, 2021 | 2020 | Percent Change | Nine months ended September 30, 2021 | 2020 | Percent Change |
|---|---|---|---|---|---|---|
| | *(thousands of dollars)* | | | *(thousands of dollars)* | | |
| Heavy oil | 7,303 | - | 100 | 14,771 | - | 100 |
| Natural gas and natural gas liquids | 20 | - | 100 | 258 | 72 | 258 |
| Total royalty expense | 7,323 | - | 100 | 15,029 | 72 | N/A |
| Percentage of total product sales, net of blending | 15.0% | - | 100 | 13.8% | 2.8% | 393 |
| Per boe ($) | 10.46 | - | 100 | 8.66 | 0.42 | 1962 |

Royalty expense consists of crown royalties payable to the Alberta and New Brunswick provincial governments and the gross overriding royalty ("GORR") payable to Topaz Energy Corp. (Topaz Energy Corp. acquired the GORR from Cenovus Energy Inc. ("Cenovus") in May 2021). Under the Alberta Modernized Royalty Framework ("MRF"), the Company will pay a flat royalty of 5% on a well's production until the well's total revenue exceeds the Drilling and Completion Cost Allowance (C*), then royalty rates increase on a sliding scale up to 40% depending on commodity reference pricing.

Headwater's average corporate royalty rate was 15.0% during the third quarter of 2021. The Company's average corporate royalty rate was 13.8% for the nine months ended September 30, 2021 compared to an average royalty rate of 2.8% for the nine months ended September 30, 2020, reflecting crown and GORR royalties incurred on the Company's Marten Hills assets.

Headwater's average corporate royalty rate increased to 15.0% during the third quarter of 2021 from 14.4% during the second quarter of 2021 and from 10.5% during the first quarter of 2021. Due to a significant increase in Headwater's realized heavy oil sales price, several Marten Hills wells' cumulative revenues exceeded C* and have reverted to the sliding scale royalty under the MRF, resulting in a higher Alberta crown royalty rate.

## Transportation Expense

| | Three months ended September 30, 2021 | Three months ended September 30, 2020 | Percent Change | Nine months ended September 30, 2021 | Nine months ended September 30, 2020 | Percent Change |
|---|---|---|---|---|---|---|
| | *(thousands of dollars)* | | | *(thousands of dollars)* | | |
| Transportation expense | 6,079 | - | 100 | 13,637 | - | 100 |
| Per boe ($) | 8.68 | - | 100 | 7.86 | - | 100 |

Transportation expense includes clean oil trucking, terminal fees and pipeline tariffs incurred to move production to the sales point.

For the three and nine months ended September 30, 2021, transportation expense increased to $6,079 thousand and $13,637 thousand, respectively, as a result of transportation costs incurred related to the Company's Marten Hills assets.

Headwater's transportation expense was $8.68 per boe during the third quarter of 2021 consistent with transportation expense of $8.21 per boe during the second quarter of 2021. Headwater's transportation increased during the second and third quarters of 2021 compared to transportation expense of $6.04 per boe during the first quarter of 2021 as a result of reduced production volumes from McCully due to the shut-in effective May 1, 2021.

With commissioning of the Company's 15,000 bbls/d oil processing facility expected in mid-January 2022, Headwater's transportation costs are expected to decrease from the current levels to approximately $3.50 per boe.

## Production Expense

| | Three months ended September 30, 2021 | Three months ended September 30, 2020 | Percent Change | Nine months ended September 30, 2021 | Nine months ended September 30, 2020 | Percent Change |
|---|---|---|---|---|---|---|
| | *(thousands of dollars)* | | | *(thousands of dollars)* | | |
| Production expense | 3,099 | 519 | 497 | 8,472 | 1,700 | 398 |
| Per boe ($) | 4.42 | - | 100 | 4.88 | 9.92 | (51) |

Production expenses in the three and nine months ended September 30, 2021, were $3,099 thousand and $8,472 thousand, respectively, compared to $519 thousand and $1,700 thousand in the corresponding periods of 2020. The increase in production expense reflects production expense incurred related to the Company's Marten Hills assets.

Production expenses per boe averaged $4.42 per boe and $4.88 per boe during the three and nine months ended September 30, 2021. Production expenses per boe decreased during the nine months ended September 30, 2021, when compared to the corresponding period of 2020, due to the integration of the Marten Hills assets which carry lower costs per boe than Headwater's historical average.

Headwater's production expense decreased to $4.42 per boe during the third quarter of 2021 from $4.89 per boe in the second quarter of 2021 and $5.62 per boe in the first quarter of 2021 due primarily to lower water handling and disposal costs and increased production volumes offsetting fixed production expenses with respect to the Company's heavy oil production.

## General and Administrative ("G&A") Expenses

| | Three months ended September 30, 2021 | Three months ended September 30, 2020 | Percent Change | Nine months ended September 30, 2021 | Nine months ended September 30, 2020 | Percent Change |
|---|---|---|---|---|---|---|
| | *(thousands of dollars)* | | | *(thousands of dollars)* | | |
| G&A expenses | 1,709 | 614 | 178 | 4,891 | 2,173 | 125 |
| Overhead recoveries & capitalized G&A | (726) | (7) | 103 | (2,090) | (41) | 4998 |
| Net G&A expenses | 983 | 607 | 62 | 2,801 | 2,132 | 31 |
| Per boe ($) | 1.40 | - | 100 | 1.61 | 12.44 | (87) |

The Company incurred gross G&A expenses of $1,709 thousand and $4,891 thousand, respectively, during the three and nine months ended September 30, 2021, compared to $614 thousand and $2,173 thousand in the corresponding periods of 2020. Increased G&A costs before recoveries and capitalization were mainly the result of a larger workforce to accommodate Headwater's Marten Hills assets and include increased employee related costs, software fees and professional fees. Headwater recognized overhead recoveries and capitalized G&A of $726 thousand and $2,090 thousand, respectively, during the three and nine months ended September 30, 2021 as a result of the Company's significant capital expenditure program.

G&A expenses for the nine months ended September 30, 2021, were $1.61 per boe, compared to $12.44 per boe in the corresponding period of 2020. The decrease in G&A expenses per boe is a result of a significant increase in sales volumes from the Marten Hills assets.

## Interest Income and Other Expense

| | Three months ended September 30, 2021 | Three months ended September 30, 2020 | Percent Change | Nine months ended September 30, 2021 | Nine months ended September 30, 2020 | Percent Change |
|---|---|---|---|---|---|---|
| | *(thousands of dollars)* | | | *(thousands of dollars)* | | |
| Interest income | 154 | 288 | (47) | 504 | 908 | (44) |
| Foreign exchange gains (losses) | 12 | (1) | (1300) | (367) | 153 | (340) |
| Accretion | (92) | (29) | 217 | (231) | (117) | 97 |
| Interest on lease liability | (14) | (8) | 75 | (22) | (11) | 100 |
| Total interest income and other | 60 | 250 | (76) | (116) | 933 | (112) |
| Per boe ($) | 0.09 | - | 100 | (0.07) | 5.45 | (101) |

Interest income and other decreased for both the three and nine months ended September 30, 2021, primarily due to foreign exchange losses and lower interest income.

Realized foreign exchange gains and losses will vary depending on the fluctuation in the exchange rate between the timing of sales incurred which are denominated in US dollars and the timing of the settlement of the underlying receivable. The Company realized foreign exchange gains of $12 thousand in the three months ended September 30, 2021, and foreign exchange losses of $367 thousand in the nine months ended September 30, 2021. The realized losses in the nine months ended September 30, 2021 compared to the realized gains in the corresponding period of the prior year are attributable to a stronger Canadian dollar throughout 2021. The Company manages fluctuations in foreign exchange gains and losses by entering into foreign exchange contracts to fix the foreign exchange rate. Refer to the "Gains (Losses) on Financial Derivatives" for more information.

Interest income decreased in both the three and nine months ended September 30, 2021, compared to the same periods in the prior year, due to a lower average cash balance on hand and a lower interest rate earned in 2021 when compared to 2020. The Bank of Canada dropped its overnight interest rate by 150 basis points from 1.75% to 0.25% in March 2020 as a response to economic uncertainty due to the COVID-19 pandemic. Additionally, the Company's $15 million guaranteed investment certificate was redeemed on April 1, 2021, at a maturity rate of 1.65%.

## Remeasurement Loss on Warrant Liability

| | Three months ended September 30, | | Percent Change | Nine months ended September 30, | | Percent Change |
|---|---|---|---|---|---|---|
| | 2021 | 2020 | | 2021 | 2020 | |
| | *(thousands of dollars)* | | | *(thousands of dollars)* | | |
| Remeasurement loss on warrant liability | 2,762 | - | 100 | 27,930 | - | 100 |
| Per boe ($) | 3.94 | - | 100 | 16.10 | - | 100 |

The Company issued 15 million warrants (the "Cenovus Warrants") to a subsidiary of Cenovus on December 2, 2020 with an exercise price of $2.00 and an expiry date of December 2, 2023.

The Cenovus Warrants are revalued every reporting period using a Monte Carlo simulation pricing model. During the three and nine months ended September 30, 2021, the Company recognized a remeasurement loss on the warrant liability of $2,762 thousand and $27,930 thousand, respectively, as a result of the increase in the Company's closing share price to $4.55 on September 30, 2021.

As at September 30, 2021, all 15 million Cenovus Warrants remained outstanding. Headwater has the right, after twelve months have elapsed from December 2, 2020, and provided the 20-day volume weighted average share price of the Company's common shares exceeds the exercise price of the Cenovus Warrants, to require the holder to exercise all or a portion of the then outstanding Cenovus Warrants. The Cenovus Warrants issued were classified as a financial liability as a result of a cashless exercise provision and are therefore carried at fair value through profit or loss. In no event will the Company be required to settle the Cenovus Warrants through a cash payment.

## **Stock-based Compensation**

| | Three months ended September 30, 2021 | Three months ended September 30, 2020 | Percent Change | Nine months ended September 30, 2021 | Nine months ended September 30, 2020 | Percent Change |
|---|---|---|---|---|---|---|
| | *(thousands of dollars)* | | | *(thousands of dollars)* | | |
| Stock options | 1,065 | 485 | 120 | 2,884 | 876 | 229 |
| Deferred share units | 8 | 7 | 14 | 82 | 26 | 215 |
| Capitalized stock-based compensation | (465) | - | 100 | (1,228) | - | 100 |
| Stock-based compensation expense | 608 | 492 | 24 | 1,738 | 902 | 93 |
| Per boe ($) | 0.87 | - | 100 | 1.00 | 5.26 | (81) |

During the three and nine months ended September 30, 2021, stock-based compensation expense with respect to stock options increased to $1,065 thousand and $2,884 thousand, respectively, from $485 thousand and $876 thousand in the corresponding periods of 2020. Stock-based compensation expense increased in both the three and nine months ended September 30, 2021, as the fair value of the new grants is higher than in 2020 due to an increase in the Company's share price. Stock-based compensation is recorded over a three-year vesting period using graded amortization resulting in a higher proportion of expense being recognized earlier in the vesting term. Headwater capitalized $465 thousand and $1,228 thousand, respectively, of stock-based compensation during the three and nine months ended September 30, 2021 as a result of the Company's significant capital expenditure program.

Stock-based compensation relating to deferred share units ("DSUs") is due to the change in fair value of the DSUs over the period resulting from a corresponding change in the Company's share price. The DSU liability as at September 30, 2021 of $173 thousand is based on a fair value of $4.55 per DSU which is the Company's closing share price on September 30, 2021 (December 31, 2020 - $2.39 per DSU).

Stock Option Plans

The Company has a stock option plan ("Old Option Plan") under which options to purchase common shares of the Company may be granted to directors, officers, employees and consultants of the Company. The exercise price of each option granted under the Old Option Plan is based on the closing price of the common shares on the Toronto Stock Exchange ("TSX") on the trading day prior to the date the option was granted. Options granted under the Old Option Plan generally vest equally over a three-year period and expire four to five years after the grant date. The Company does not intend to grant any additional options under the Old Option Plan.

On March 25, 2020, the Company's Board of Directors approved a new share option plan ("New Option Plan") under which options to purchase common shares of the Company may be granted to directors, officers, employees and consultants of the Company. Under the terms of the New Option Plan, an aggregate number of options equal to 8.0% of the aggregate number of issued and outstanding common shares less the aggregate number of common shares issuable pursuant to outstanding options under the Old Option Plan may be granted. The exercise price of each option granted under the New Option Plan is based on the closing price of the common shares on the TSX on the trading day prior to the date the option was granted and generally options vest equally over a three-year period and expire four years from the date of grant.

The New Option Plan was approved by the Company's shareholders at the Company's annual and special meeting of shareholders held on June 15, 2020.

As at September 30, 2021, there were 1,141,668 stock options outstanding under the Old Option Plan and 8,519,667 stock options outstanding under the New Option Plan.

## Depletion & Depreciation

| | Three months ended September 30, 2021 | 2020 | Percent Change | Nine months ended September 30, 2021 | 2020 | Percent Change |
|---|---|---|---|---|---|---|
| | *(thousands of dollars)* | | | *(thousands of dollars)* | | |
| Depletion & depreciation | 10,889 | 75 | N/A | 28,598 | 3,334 | 758 |
| Per boe ($) | 15.55 | - | 100 | 16.48 | 19.46 | (15) |

Depletion expense is calculated using the unit-of-production method which is based on production volumes in relation to the proved plus probable reserves base.

Depletion and depreciation expense for the three and nine months ended September 30, 2021, was $10,889 thousand and $28,598 thousand, respectively, compared to $75 thousand and $3,334 thousand recorded in the corresponding periods of 2020. The increase in the absolute level of depletion expense for the three and nine months ended September 30, 2021 is due to both an increase in production and the carrying value of assets subject to depletion, resulting from the acquisition of Marten Hills assets in December 2020.

Depletion and depreciation per boe decreased during the nine months ended September 30, 2021, when compared to the corresponding period of 2020, primarily due to the Marten Hills assets acquired at a lower cost per boe. The depletion rate in respect to the Company's McCully assets during the nine months ended September 30, 2021 was consistent with the comparable period of 2020, as the increase to the depletion base from the $15.1 million impairment reversal recognized in the fourth quarter of 2020 was offset by the change in basis of reserves from proved reserves to proved plus probable reserves applied in the fourth quarter of 2020.

Depletion and depreciation expense per boe decreased to $15.55 per boe during the three months ended September 30, 2021 from $17.28 per boe in the second quarter of 2021 and $16.90 per boe in the first quarter of 2021 as reserve additions were only partially offset by capital additions.

## Impairment Assessment

Q3 2021 Impairment Assessment – Alberta CGU

The Company concluded there are no indicators of impairment for its Alberta CGU as at September 30, 2021.

Q3 2021 Impairment Reversal – New Brunswick CGU

In the third quarter of 2021, due to a significant increase in forecast natural gas pricing, the Company determined an indicator of impairment reversal was present for its New Brunswick CGU. As a result, the Company completed an impairment reversal test and recognized a reversal of previous impairment losses of $16,293 thousand; this amount represents the full amount available to be reversed.

The recoverable amount was estimated based on the FVLCD methodology which is calculated using the present value of the CGU's estimated cash flows associated with proved and probable natural gas reserves. The cash flow information was derived from an internal reserve report on the Company's McCully assets which was prepared by management as of September 30, 2021.The projected cash flows used in the FVLCD calculation reflect market assessments of key assumptions as at September 30, 2021, including long-term forecasts for natural gas commodity prices, inflation rates and foreign exchange rates (Level 3 fair value inputs). Cash flow forecasts are also based on the Company's reserves and individual well production profiles, operating and royalty costs and future development costs. Royalty rates used in the FVLCD calculation are consistent with the New Brunswick government's royalty regime in effect as of September 30, 2021.

The discount rate used in the impairment reversal calculation was 12% and was determined based on a peer group weighed average cost of capital factoring in risks specific to the types of reserves. The carrying value of the New Brunswick CGU at September 30, 2021 was $48.9 million prior to any impairment reversal.

Forecast natural gas commodity pricing used in the FVLCD calculation as at September 30, 2021 reflects the benchmark prices set forth in the table below. McCully natural gas prices were calculated by adjusting the Algonquin city-gates natural gas prices to reflect the expected premiums received at Headwater's delivery point, net of transportation costs, if applicable, and heat content.

| | 2021 | 2022 | 2023 | 2024 | 2025 | 2026-2030 | Thereafter |
|---|---|---|---|---|---|---|---|
| Algonquin city-gates ($US/mmbtu) | 10.50 | 7.25 | 5.44 | 4.37 | 4.46 | 4.55 - 4.92 | +2%/year |
| McCully ($CDN/mcf) (1) | 17.56 | 12.43 | 8.93 | 6.25 | 6.86 | 7.00 – 7.57 | +2%/year |
| Exchange rate ($US/$CDN) | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 | 0.80 |

(1) Realized pricing reflects natural gas production through the winter producing months (January to April and November to December of the applicable year) in 2021 to 2023.

Changes in key assumptions, such as a downward revision in natural gas reserves, a decrease in forecast natural gas commodity prices, changes in foreign exchange rates, an increase in royalties, operating costs or future development costs would decrease the recoverable amount of the CGU and the amount of the impairment reversal with a corresponding decrease to the Company's net income for the period.

As at September 30, 2021, a 1% increase in the discount rate and/or a 5% decrease in forecast operating cash flows would result in the following reduction to the Company's impairment reversal for the period:

| | Decrease to impairment reversal |
|---|---|
| | $ |
| 1% increase in discount rate | - |
| 5% decrease in cash flows | (268) |
| 1% increase in discount rate and 5% decrease in cash flows | (2,210) |

## Decommissioning Liabilities

As at September 30, 2021, the decommissioning liabilities of the Company were $21,879 thousand. The Company recorded an increase of $5,161 thousand in the obligation from the decommissioning liability of $16,718 thousand as at December 31, 2020. This increase of $5,161 thousand is due to additions of $7,241 thousand as a result of the Company's capital expenditure program and accretion expense of $231 thousand partially offset by a downward change in estimate of $2,311 thousand. The change in estimate is a result of an increase to the risk-free rate to 2.0% at September 30, 2021 from 1.2% at December 31, 2020, partially offset by an increase to the inflation rate to 1.7% at September 30, 2021 from 1.5% at December 31, 2020. The total undiscounted uninflated amount of estimated cash flows required to settle these obligations is $22,963 thousand (December 31, 2020 - $15,456 thousand).

## Deferred Income Taxes

At September 30, 2021, the Company had approximately $282 million of tax pools available to be applied against future taxable income. The federal tax pools are estimated as follows:

| *($ thousands)* | Estimated balance at September 30, 2021 |
|---|---|
| Canadian oil and gas property expense | 67,550 |
| Canadian development expense | 53,343 |
| Canadian exploration expense | 77,298 |
| Undepreciated capital cost | 53,558 |
| Non-capital losses | 25,320 |
| Other | 5,205 |
| Total | 282,274 |

## Net Income (Loss), Adjusted Net Income (Loss) and Adjusted Funds Flow from Operations

The Company's net income generating capability is a direct result of production and commodity prices. For the three months ended September 30, 2021, Headwater generated net income of $26,106 thousand compared to a net loss of $1,723 thousand for the three months ended September 30, 2020, primarily due to operating cash flow from the recently acquired Marten Hills assets of $32,723 thousand and the McCully PP&E impairment reversal of $16,293 thousand, partially offset by depletion and depreciation expense of $10,889 thousand, an unrealized loss on financial derivatives of $7,346 thousand and the remeasurement loss on the warrant liability of $2,762 thousand. Adjusted net income increased to $28,868 thousand for the three months ended September 30, 2021, after adjusting for the remeasurement loss on the warrant liability.

Adjusted funds flow from operations increased to $31,524 thousand for the three months ended September 30, 2021, from $837 thousand used in operations for the three months ended September 30, 2020, due to operating cash flow generated from the Company's Marten Hills assets.

Refer to "Non-IFRS Financial Measures" for a reconciliation between IFRS and Non-IFRS measures.

The following table summarizes the operating netback, adjusted funds flow netback and adjusted net income (loss) on a barrel of oil equivalent basis:

| | Three months ended September 30, 2021 | 2020 | Percent Change | Nine months ended September 30, 2021 | 2020 | Percent Change |
|---|---|---|---|---|---|---|
| | ($/boe) | | | ($/boe) | | |
| Sales, net of blending [1] | 69.73 | - | 100 | 63.05 | 16.76 | 276 |
| Realized gains (losses) on financial derivatives | - | - | - | (0.23) | 22.97 | (101) |
| Royalties | (10.46) | - | 100 | (8.66) | (0.42) | 1962 |
| Net sales | 59.27 | - | 100 | 54.16 | 39.31 | 38 |
| Transportation expense | (8.68) | - | 100 | (7.86) | - | 100 |
| Production expense | (4.42) | - | 100 | (4.88) | (9.92) | (51) |
| Operating netback [2] | 46.17 | - | 100 | 41.42 | 29.39 | 41 |
| General and administrative expenses | (1.40) | - | 100 | (1.61) | (12.44) | (87) |
| Interest income and other expense [3] | 0.24 | - | 100 | 0.08 | 6.19 | (99) |
| Adjusted funds flow netback [2] | 45.01 | - | 100 | 39.89 | 23.14 | 72 |
| Transaction costs | - | - | - | - | (25.57) | (100) |
| Unrealized losses on financial derivatives | (10.49) | - | 100 | (5.22) | (9.41) | (45) |
| Stock-based compensation expense | (0.87) | - | 100 | (1.00) | (5.26) | (81) |
| Depletion and depreciation | (15.55) | - | 100 | (16.48) | (19.46) | (15) |
| Impairment reversal | 23.26 | - | 100 | 9.39 | - | 100 |
| Accretion and other expense | (0.15) | - | 100 | (0.15) | (0.74) | (80) |
| Exploration and evaluation expense | - | - | - | - | (22.29) | (100) |
| Adjusted net income (loss) [2] | 41.21 | - | 100 | 26.43 | (59.59) | (144) |
| Remeasurement loss on warrant liability | (3.94) | - | 100 | (16.10) | - | 100 |
| Net income (loss) [2] | 37.27 | - | 100 | 10.33 | (59.59) | (117) |

(1) Realized heavy oil prices are calculated based on sales, net of blending expense.
(2) Operating metric. See "Operating Metrics" advisory. Netbacks are calculated using average sales volumes.
(3) Excludes accretion on decommissioning liabilities and interest on lease liability.

## Capital Expenditures

The Company's capital expenditures for the three and nine months ended September 30, 2021, are detailed below:

| | Three months ended September 30, 2021 | 2020 | Percent Change | Nine months ended September 30, 2021 | 2020 | Percent Change |
|---|---|---|---|---|---|---|
| | (thousands of dollars) | | | (thousands of dollars) | | |
| Lease acquisition and retention | 1,048 | - | 100 | 1,438 | - | 100 |
| Geological and geophysical | 84 | - | 100 | 448 | - | 100 |
| Site preparation | 2,563 | - | 100 | 4,943 | - | 100 |
| Drilling and completions | 21,550 | - | 100 | 48,820 | - | 100 |
| Equipping and facilities | 12,047 | 61 | N/A | 35,686 | 497 | 7080 |
| Corporate | 1 | - | 100 | 11 | 32 | (66) |
| Total capital expenditures | 37,293 | 61 | N/A | 91,346 | 529 | N/A |

During the nine months ended September 30, 2021, Headwater drilled a total of 40 (40.0 net) crude oil wells (6-leg and 8-leg multi-laterals), 3 (3.0 net) source wells and 1 (1.0 net) stratigraphic test well with a 100% success rate.

During the three months ended September 30, 2021, the Company invested a total of $37.3 million on capital expenditures including $21.6 million on drilling and completions, $12.0 million on equipping and facilities, $2.6 million on site preparation and $1.1 million on lease acquisition and geological and geophysical costs. Headwater commenced construction of its 15,000 bbls/d oil facility during the three months ended September 30, 2021, following procurement of equipment in the second quarter of 2021.

During the nine months ended September 30, 2021, the Company invested a total of $91.3 million on capital expenditures including $48.8 million on drilling and completions, $35.7 million on equipping and facilities, $4.9 million on site preparation and $1.9 million on lease acquisition and geological and geophysical costs. Headwater constructed a joint gas processing facility during the nine months ended September 30, 2021 and commissioned the facility in the third quarter of 2021 with first sales gas realized in September 2021.

## Environmental, Social and Governance ("ESG") Update

Headwater remains committed to strong ESG performance. Recent achievements related to the Company's ESG strategy include:

- The Company's joint gas processing facility, commissioned in the third quarter of 2021, has resulted in an approximate 50% reduction in Headwater's CO2e emissions intensity from the first quarter of 2021.

- Headwater's freshwater usage intensity has decreased by greater than 80% and placed the Company in the top decile of its peer group, due to changes in drilling strategy using primarily oil-based mud systems.

Headwater's Board of Directors continually focuses on ensuring that its governance structure is appropriate and following best practices given Headwater's size and stage of development. The primary responsibility of Headwater's Corporate Governance and Sustainability Committee, which is comprised of independent members of the Board of Directors, is to develop the Company's approach to matters concerning corporate governance, sustainability, human resources and compensation. In addition, the Board of Directors has also established the Audit Committee and Reserves Committee, which are both comprised of independent members of the Board, to ensure the integrity of the financial and reserves reporting of the Company. For additional information relating to the governance policies and structure of the Company see the Company's management information circular dated March 29, 2021 for the annual and special meeting of the shareholders held on May 13, 2021, which is available on SEDAR at www.sedar.com and the information under the heading Corporate Responsibility on the Company's website at at www.headwaterexp.com.

## 2021 Revised Guidance

On November 10, 2021, the Board of Directors approved revised 2021 guidance. Headwater expects to fund the increase in capital expenditures through existing working capital and forecasted cash flows from operating activities.

The following table summarizes Headwater's revised November 10, 2021 guidance and the previously released guidance from August 5, 2021:

| | Previous 2021 Guidance August 5, 2021 | Revised 2021 Guidance November 10, 2021 |
|---|---|---|
| **Average Daily Production** | | |
| Annual 2021 daily production (boe/d) (1) | 7,250 | 7,400 |
| Annual 2021 heavy oil production (bbls/d) | 6,530 | 6,690 |
| Annual 2021 daily natural gas production (mmcf/d) | 4.3 | 4.2 |
| Fourth quarter 2021 daily production (boe/d) (1) | 10,250 | 10,400 |
| Fourth quarter 2021 daily heavy oil production (bbls/d) | 9,250 | 9,410 |
| Fourth quarter 2021 daily natural gas production (mmcf/d) | 6.0 | 6.0 |
| **Pricing** | | |
| Crude oil - WTI ($US/bbl) | 66.00 | 68.95 |
| Crude oil - WCS ($Cdn/bbl) | 67.00 | 69.80 |
| Exchange rate ($Cdn/$US) | 0.80 | 0.80 |
| Natural gas - AGT ($US/mmbtu) (2) | 5.00 | 6.70 |
| **Financial Summary ($millions)** | | |
| Capital expenditures | 130 | 140 |
| Estimated exit adjusted working capital surplus (3) (4) | 65 | 66 |

(1) See “Barrels of Oil Equivalent”.
(2) The AGT price is the volume weighted average price for the winter producing months in the McCully field which include January – April 2021 and November – December 2021.
(3) Non-IFRS measure. See “Non-IFRS Financial Measures” advisory.
(4) Does not contemplate Headwater exercising its call right on the Cenovus Warrants which could result in exercise proceeds of up to $30 million.

## 2022 Budget

On November 10, 2021, the Board of Directors approved the 2022 budget. Headwater expects to fund the 2022 capital expenditures through existing working capital and forecasted cash flows from operating activities.

The following table summarizes Headwater’s 2022 budget:

| | 2022 Budget |
|---|---|
| **Average Daily Production** | |
| Annual 2022 daily production (boe/d) (1) | 12,500 |
| Annual 2022 daily heavy oil production (bbls/d) | 11,500 |
| Annual 2022 daily natural gas production (mmcf/d) | 6.2 |
| Fourth quarter 2022 daily production (boe/d) (1) | 15,000 |
| Fourth quarter 2022 daily heavy oil production (bbls/d) | 13,770 |
| Fourth quarter 2022 daily natural gas production (mmcf/d) | 7.4 |
| **Pricing** | |
| Crude oil - WTI ($US/bbl) | 75.00 |
| Crude oil - WCS ($Cdn/bbl) | 74.00 |
| Exchange rate ($Cdn/$US) | 0.80 |
| Natural gas - AGT ($US/mmbtu) (2) | 12.95 |
| **Financial Summary ($millions)** | |
| Adjusted funds flow from operations (3) | 207 |
| Capital expenditures | 120 |
| Estimated exit adjusted working capital surplus (3) (4) | 153 |

(1) See “Barrels of Oil Equivalent”.
(2) The AGT price is the volume weighted average price for the winter producing months in the McCully field which include January – April 2022 and November – December 2022.
(3) Non-IFRS measure. See “Non-IFRS Financial Measures” advisory.
(4) Does not contemplate Headwater exercising its call right on the Cenovus Warrants which could result in exercise proceeds of up to $30 million.

2020 Marten Hills Acquisition

On November 8, 2020, the Company entered into a purchase and sale agreement with Cenovus to acquire Cenovus' Marten Hills assets. The acquisition was completed on December 2, 2020, for estimated total consideration of $135.3 million, comprised of $32.8 million of cash (inclusive of interim adjustments), $96.5 million of common shares valued using Headwater's closing share price on the closing date and $6.0 million attributed to the Cenovus Warrants. The Cenovus Warrants have a three-year term and an exercise price of $2.00 per common share.

The acquired Marten Hills assets include 100% working interest in Marten Hills heavy oil properties (average 18 - 22˚ API) and 270 net sections of Clearwater rights. As part of the acquisition, Cenovus reserved a GORR on the Marten Hills assets which was subsequently sold to Topaz Energy Corp. in May 2021. The Company assumed certain transportation commitments from Cenovus. Refer to heading "Contractual Obligations and Commitments" for additional information.

## Drilling Activity

The following table summarizes the Company's drilling results:

| | Three months ended September 30, | | | | Nine months ended September 30, | | | |
|---|---|---|---|---|---|---|---|---|
| | 2021 | | 2020 | | 2021 | | 2020 | |
| | Gross | Net | Gross | Net | Gross | Net | Gross | Net |
| Crude oil [(1)] | 21 | 21.0 | - | - | 40 | 40.0 | - | - |
| Natural gas | - | - | - | - | - | - | - | - |
| Injection | - | - | - | - | - | - | - | - |
| Source/stratigraphic test | 1 | 1.0 | - | - | 4 | 4.0 | - | - |
| Dry and abandoned | - | - | - | - | - | - | - | - |
| Total | 22 | 22.0 | - | - | 44 | 44.0 | - | - |
| Success | 100% | 100% | N/A | N/A | 100% | 100% | N/A | N/A |

(1) Of the 40 (40.0 net) crude oil wells drilled during the nine months ended September 30, 2021, 3 (3.0 net) of these crude oil wells were converted to water injection wells (1 in April 2021 and 2 in October 2021).

## Liquidity and Capital Resources

Headwater's liquidity depends on the Company's cash flows from operations, supplemented as necessary by equity and debt financings. At September 30, 2021, the Company had cash and cash equivalents of $84.1 million, adjusted working capital of $63.7 million and no outstanding debt. The Company expects to have adequate liquidity to fund the remaining 2021 capital expenditure budget of $140 million, the 2022 capital expenditure budget of $120 million and contractual obligations in the near term through existing working capital and forecasted cash flows from operations. Headwater anticipates that it will make use of debt or equity financing for any substantial expansion of its capital program or to finance any significant acquisitions.

Contractual Obligations and Commitments

The following table details the contractual maturities of the Company's liabilities as at September 30, 2021:

| | Within 1 year | 1 to 5 years |
|---|---|---|
| | $ | $ |
| Accounts payable and accrued liabilities | 44,834 | - |
| Financial derivative liability | 8,984 | - |
| DSU liability | 173 | - |
| Lease liability | 619 | 573 |
| Total | 54,610 | 573 |

As at September 30, 2021, the Company is committed to future payments under the following agreements:

| | Total | 2021 | 2022 | 2023 | 2024 | 2025 | Thereafter |
|---|---|---|---|---|---|---|---|
| | $ | $ | $ | $ | $ | $ | $ |
| Transportation (1) | 106,126 | 2,322 | 9,239 | 10,750 | 10,964 | 12,041 | 60,810 |
| Capital commitment (2) | 11,700 | - | 11,700 | - | - | - | - |
| Total (3) | 117,826 | 2,322 | 20,939 | 10,750 | 10,964 | 12,041 | 60,810 |

(1) At September 30, 2021, Headwater has the following transportation commitments:
   a. 10- year take-or-pay transportation agreement with a minimum volume commitment of 10,000 boe/d.
   b. 10- year financial commitment at $1.9 million per year adjusted for inflation.
   c. 10- year take-or-pay transportation agreement with a current minimum volume commitment of 1,250 boe/d increasing to 6,250 boe/d in year 3 and to 9,000 boe/d in year 6.
   d. Take-or-pay agreement to January 2022 for minimum oil processing of 200 mboe per month.

(2) Headwater has a development agreement under which the Company committed to spend $100 million in capital expenditures on certain oil and gas properties by December 31, 2022, unless otherwise extended by the counterparty. The Company expects to fund these expenditures through its working capital surplus and cash flows from operating activities. As at September 30, 2021, the remaining capital commitment is approximately $12 million.

(3) Excludes leases accounted for under IFRS 16.

## Common Share Information

Share Capital

| *(thousands)* | Three months ended September 30, 2021 | Three months ended September 30, 2020 | Nine months ended September 30, 2021 | Nine months ended September 30, 2020 |
|---|---|---|---|---|
| Weighted average outstanding common shares (1) | | | | |
| -Basic | 202,313 | 145,044 | 198,385 | 131,997 |
| -Diluted | 218,190 | 145,044 | 214,166 | 131,997 |
| Outstanding securities at September 30, 2021 | | | | |
| -Common shares | | | | 202,466 |
| -Stock options – weighted average strike price of $2.29 | | | | 9,662 |
| -Recapitalization Warrants (as defined below) – strike price $0.92 (2) | | | | 15,420 |
| -Cenovus Warrants – strike price of $2.00 (3) | | | | 15,000 |

(1) The Company uses the treasury stock method to determine the dilutive effect of stock options and warrants. Under this method, only “in-the-money” dilutive instruments impact the calculation of diluted income per common share. This method also assumes that the proceeds received from the exercise of all “in-the-money” dilutive instruments are used to repurchase shares at the average market price.

(2) Issued on the Recapitalization Transaction (as defined below) as part of the non-brokered private placement. As at September 30, 2021, these Recapitalization Warrants (as defined below) are fully exercisable with a strike price of $0.92.

(3) Issued as partial consideration for the Marten Hills assets. As at September 30, 2021, these Cenovus Warrants are fully exercisable with a strike price of $2.00.

Changes to share capital for the nine months ended September 30, 2021 were the following:

- 1,441 thousand stock options were exercised for 1,116 thousand common shares. Contributed surplus related to the stock options exercised of $783 thousand was transferred to capital stock.

- 6,257 thousand Recapitalization Warrants were exercised for 6,244 thousand common shares. The associated fair value of the Recapitalization Warrants of $2,210 thousand was transferred to capital stock.

- Total proceeds received by the Company for the stock option and Recapitalization Warrant exercises were $5.7 million for the nine months ended September 30, 2021.

Recapitalization Transaction

On March 4, 2020, the Company completed its recapitalization transaction (the "Recapitalization Transaction"), which involved the following:

- A non-brokered private placement of 21,739,130 units of the Company at a price of $0.92 per unit for aggregate gross proceeds of $20.0 million. Each unit was comprised of one common share and one common share purchase warrant ("Recapitalization Warrant") of the Company. Each Recapitalization Warrant entitles the holder to purchase one common share at a price of $0.92 per common share for a period of 4 years from the issuance date. Pursuant to the rules of the TSX, the non-brokered private placement was approved by shareholders of the Company at a special meeting of the shareholders held on March 4, 2020. As at September 30, 2021, the Recapitalization Warrants were fully vested and exercisable.

- Concurrently with the closing of the non-brokered private placement, the appointment of a new management team and reconstitution of the Board of Directors was completed.

- A brokered private placement of 32,608,696 subscription receipts ("Subscription Receipts") of the Company, which were sold at a price of $0.92 per Subscription Receipt through a syndicate of dealers for aggregate gross proceeds of $30.0 million, was completed on February 11, 2020. Pursuant to the terms of the Subscription Receipts, upon completion of the non-brokered private placement, reconstitution of the Board of Directors and appointment of the new management team on March 4, 2020, the net proceeds of the brokered private placement were released to the Company and each holder of Subscription Receipts received one common share for each Subscription Receipt held.

- The Company also changed its name to Headwater Exploration Inc., which name change was also approved by shareholders of the Company at the special meeting of the shareholders held on March 4, 2020.

- In connection with the Recapitalization Transaction, the Company incurred $4.4 million of transaction costs and $1.9 million in share issue costs.

## Total Market Capitalization

The Company's market capitalization at September 30, 2021 was approximately $921.2 million.

| *(thousands)* | September 30, 2021 |
|---|---|
| Common shares outstanding | 202,466 |
| Share price (1) | $ 4.55 |
| Total market capitalization | $921,220 |

(1) Represents the closing price on the TSX on September 30, 2021.

As at November 10, 2021 the Company had 202,485,486 common shares outstanding.

| (thousands) | November 10, 2021 |
|---|---|
| Outstanding securities at November 10, 2021 | |
| -Common shares | 202,485 |
| -Stock options – weighted average strike price of $2.32 | 9,667 |
| -Recapitalization Warrants – strike price $0.92 | 15,420 |
| -Cenovus Warrants– strike price of $2.00 | 15,000 |

## Related Party Transactions

Transactions with Cenovus

As at September 30, 2021, Cenovus owned approximately 25% of the Company's basic common shares outstanding and two of its senior officers were serving as directors of Headwater. Headwater and Cenovus have entered into a marketing agreement that terminates on December 2, 2023. As at September 30, 2021, a receivable of $22.0 million was recorded from Cenovus for September heavy oil sales which was subsequently collected. Subsequent to September 30, 2021, Cenovus sold all of the common shares of the Company that it held through a secondary offering. Refer to "Subsequent Events" for more information.

## Summary of Quarterly Information

| | Q3/21 | Q2/21 | Q1/21 | Q4/20 | Q3/20 | Q2/20 | Q1/20 | Q4/19 |
|---|---|---|---|---|---|---|---|---|
| **Financial** *(thousands of dollars except share data)* | | | | | | | | |
| Sales, net of blending [1] | 48,841 | 37,429 | 23,122 | 6,283 | - | 565 | 2,308 | 2,310 |
| Cash flows provided by (used in) operating activities [6] | 27,888 | 23,232 | 12,783 | (1,451) | (364) | 863 | 1,182 | (192) |
| Adjusted funds flow from (used in) operations [2] | 31,524 | 23,182 | 14,479 | 4,816 | (837) | (610) | 5,413 | 1,929 |
| Per share - basic | 0.16 | 0.12 | 0.07 | 0.03 | (0.01) | - | 0.05 | 0.02 |
| - diluted [3] | 0.14 | 0.10 | 0.07 | 0.03 | (0.01) | - | 0.05 | 0.02 |
| Net income (loss) | 26,106 | 4,588 | (12,793) | 16,919 | (1,723) | (1,679) | (6,810) | 1,447 |
| Per share - basic | 0.13 | 0.02 | (0.07) | 0.10 | (0.01) | (0.01) | (0.06) | 0.02 |
| - diluted | 0.12 | 0.02 | (0.07) | 0.10 | (0.01) | (0.01) | (0.06) | 0.02 |
| Adjusted net income (loss) [2] | 28,868 | 10,561 | 6,402 | 21,208 | (1,723) | (1,679) | (6,810) | 1,447 |
| Per share - basic | 0.14 | 0.05 | 0.03 | 0.13 | (0.01) | (0.01) | (0.06) | 0.02 |
| - diluted [3] | 0.13 | 0.05 | 0.03 | 0.13 | (0.01) | (0.01) | (0.06) | 0.02 |
| Capital expenditures | 37,293 | 16,781 | 37,272 | 1,748 | 61 | 398 | 70 | 227 |
| Acquisition | - | - | - | 135,297 | - | - | - | - |
| Depletion and depreciation | 10,889 | 10,459 | 7,250 | 2,586 | 75 | 754 | 7,250 | 1,375 |
| Adjusted working capital [2] | 63,709 | 69,697 | 58,367 | 80,759 | 112,667 | 113,569 | 114,200 | 63,141 |
| Shareholders' equity | 295,528 | 268,191 | 257,461 | 269,030 | 155,148 | 156,386 | 157,235 | 114,310 |
| Weighted average shares *thousands)* | | | | | | | | |
| Basic | 202,313 | 197,445 | 195,322 | 161,365 | 145,044 | 144,749 | 105,436 | 88,147 |
| Diluted | 218,190 | 213,905 | 195,322 | 168,600 | 145,044 | 144,749 | 105,436 | 88,542 |
| Shares outstanding, end of period *(thousands)* | | | | | | | | |
| Basic | 202,466 | 202,286 | 195,574 | 195,106 | 145,044 | 145,044 | 144,327 | 88,147 |
| Diluted [9] | 240,447 | 240,257 | 240,456 | 238,121 | 158,627 | 151,381 | 145,552 | 89,842 |
| **Operating** ***(6:1 boe conversion)*** | | | | | | | | |
| Average daily production | | | | | | | | |
| Heavy oil (*bbls/d*) | 7,637 | 6,185 | 3,385 | 979 | - | - | - | - |
| Natural gas *(mmcf/d)* | 0.3 | 2.3 | 8.5 | 4.0 | - | 2.4 | 8.9 | 3.5 |
| Natural gas liquids *(bbls/d)* | - | 5 | 5 | 3 | - | - | 7 | 2 |
| Barrels of oil equivalent *(boe/d)* [4] | 7,688 | 6,565 | 4,805 | 1,646 | - | 396 | 1,487 | 586 |
| Average daily sales *(boe/d)* [4] [10] | 7,613 | 6,653 | 4,768 | 1,646 | - | 396 | 1,487 | 586 |
| Average selling prices | | | | | | | | |
| Heavy oil (*$/bbl*) | 70.00 | 64.20 | 55.72 | 45.05 | - | - | - | - |
| Natural gas *($/mcf)* | 4.49 | 2.76 | 7.48 | 5.37 | - | 2.27 | 2.49 | 6.80 |
| Natural gas liquids *($/bbl)* | - | 73.99 | 66.55 | 56.23 | - | - | 57.90 | 83.34 |
| Barrels of oil equivalent *($/boe)* [4] | 69.71 | 61.52 | 52.51 | 39.90 | - | 13.63 | 15.12 | 40.92 |
| Netbacks ($/boe) [6] [11] | | | | | | | | |
| Operating | | | | | | | | |
| Sales, net of blending [1] [5] | 69.73 | 61.83 | 53.89 | 41.50 | - | 15.67 | 17.06 | 42.84 |
| Realized gains (losses) on financial derivatives | - | 0.24 | (1.28) | 10.42 | - | - | 29.09 | 14.70 |
| Royalties | (10.46) | (8.84) | (5.49) | (3.86) | - | (0.39) | (0.42) | (0.96) |
| Transportation [1] | (8.68) | (8.21) | (6.04) | (5.10) | - | - | - | - |
| Production expense | (4.42) | (4.89) | (5.62) | (7.92) | - | (14.79) | (4.78) | (12.19) |
| Operating netback *($/boe)* | 46.17 | 40.13 | 35.46 | 35.04 | - | 0.49 | 40.95 | 44.39 |
| General and administrative | (1.40) | (1.60) | (1.97) | (4.64) | - | (23.33) | (5.05) | (13.22) |
| Interest income and other expense [8] | 0.24 | (0.23) | 0.26 | 1.39 | - | 6.00 | 4.10 | 4.73 |
| Decommissioning liabilities settled | - | - | - | - | - | - | - | (0.13) |
| Adjusted funds flow netback *($/boe)* [7] | 45.01 | 38.30 | 33.75 | 31.79 | - | (16.84) | 40.00 | 35.77 |

(1) Heavy oil sales are netted with blending expense to compare the realized price to benchmark. In the interim condensed financial statements, blending is recorded as blending and transportation expense.
(2) Non-IFRS measure. See "Non-IFRS Financial Measures" advisory.
(3) Diluted weighted average shares outstanding includes the impact of any stock options, Recapitalization Warrants and Cenovus Warrants that would be outstanding as dilutive instruments using the treasury stock method.
(4) See barrels of oil equivalent under "Oil and Gas Measures".
(5) Excludes realized and unrealized gains (losses) on financial derivative commodity contracts.
(6) Operating metric. See "Operating Metrics" advisory.
(7) Comparative period revised to reflect current period presentation. Decommissioning liabilities settled was previously not included in cash flows from operations, adjusted funds flow from operations or the adjusted funds flow netback calculation.
(8) Excludes accretion on decommissioning liabilities and interest on the lease liability.
(9) Includes in-the-money dilutive instruments as at September 30, 2021 which include 7.6 million stock options with a weighted average exercise price of $1.63, 15.4 million Recapitalization Warrants with an exercise price of $0.92 and 15 million Cenovus Warrants with an exercise price of $2.00.
(10) Includes sales of unblended heavy crude oil. The Company's heavy oil sales volumes and production volumes differ due to changes in inventory.
(11) Netbacks are calculated using average sales volumes.

Following the acquisition of the Marten Hills assets in December 2020 and Headwater's drilling program during the nine months ended September 30, 2021, the Company's sales volumes have grown significantly to 7,613 boe/d for the three months ended September 30, 2021. As a result of this production growth in combination with a higher commodity price environment, the Company's operating cash flow is significantly higher for the three months ended September 30, 2021, compared to the same period in the prior year.

During the three months ended September 30, 2021, Headwater generated adjusted net income of $28,868 thousand due to operating cash flow of $32,341 thousand and the McCully PP&E impairment reversal of $16,293 thousand, partially offset by depletion and depreciation expense of $10,889 thousand, unrealized loss on financial derivatives of $7,346 thousand, general and administrative expenses of $983 thousand and stock-based compensation expense of $608 thousand. The remeasurement loss on the warrant liability of $2,762 thousand decreased the Company's net income to $26,106 thousand for the three months ended September 30, 2021.

During the three months ended June 30, 2021, Headwater generated adjusted net income of $10,561 thousand due to operating cash flow of $24,294 thousand partially offset by depletion and depreciation expense of $10,459 thousand, unrealized loss on financial derivatives of $1,458 thousand, general and administrative expenses of $971 thousand and stock-based compensation expense of $610 thousand. The remeasurement loss on the warrant liability of $5,973 thousand decreased the Company's net income to $4,588 thousand for the three months ended June 30, 2021.

During the three months ended March 31, 2021, Headwater generated adjusted net income of $6,402 thousand due to operating cash flow from the recently acquired Marten Hills assets of $10,217 thousand and operating cash flow from the Company's McCully assets of $4,997 thousand partially offset by depletion and depreciation expense of $7,250 thousand, general and administrative expenses of $847 thousand and stock-based compensation expense of $520 thousand. The remeasurement loss on the warrant liability of $19,195 thousand contributed to the Company's net loss for the three months ended March 31, 2021 of $12,793 thousand.

During the three months ended December 31, 2020, Headwater closed the Marten Hills acquisition for estimated total consideration of $135.3 million comprised of $32.8 million of cash, $96.5 million of common shares valued using Headwater's closing share price on the closing date and $6.0 million attributed to the Cenovus Warrants. The Marten Hills assets added $4,400 thousand of heavy oil sales for the three months ended December 31, 2020. Additionally, the Company incurred $2,948 thousand of transaction costs to complete the acquisition. Headwater generated net income of $16,919 thousand in the fourth quarter of 2020 primarily due to a property, plant and equipment impairment reversal of $15,054 thousand related to the McCully CGU and a deferred income tax recovery of $7,277 thousand.

During the three months ended March 31, 2020, Headwater completed the Recapitalization Transaction which included non-brokered and brokered private placements for aggregate gross proceeds of $50 million. Headwater incurred a net loss of $6,810 thousand for the quarter primarily due to transaction costs of $4,382 thousand incurred pursuant to the Recapitalization Transaction, exploration and evaluation expense of $3,821 thousand and lower natural gas sales attributed to a lower average realized natural gas sales price.

Headwater's natural gas sales are priced at AGT. In response to higher natural gas pricing in the winter season, since 2015, the Company has shut-in most of its producing natural gas wells in the McCully field in New Brunswick for a portion of the summer and fall period to time the start-up of production, and the associated recovery of flush volumes, with peak winter pricing to maximize cash flows from operations and to retain Headwater's reserves for production in future years.

## Off-Balance Sheet Arrangements

All off-balance sheet arrangements are in the normal course of business. Refer to the commitments under the heading "Contractual Obligations and Commitments".

## Subsequent Events

Financial derivative commodity and foreign exchange contracts

Subsequent to September 30, 2021, Headwater entered into the following financial derivative commodity and foreign exchange contracts:

| Commodity | Index | Type | Term | Daily Volume | Contract Price |
|---|---|---|---|---|---|
| Natural Gas | AGT | Fixed | Dec 2021 | 2,500 mmbtu | US$17.00/mmbtu |
| Natural Gas | AGT | Fixed | Jan 1- Feb 28, 2022 | 2,500 mmbtu | Cdn$25.26/mmbtu |

| Type | Buy Currency | Sell Currency | Rate | Notional Amount | Settlement Date |
|---|---|---|---|---|---|
| Forward contract | CAD | USD | WMR noon rate, October 2021 average | US$11,300,000 | November 26, 2021 |
| Forward contract | CAD | USD | WMR noon rate, November 2021 average | US$19,000,000 | December 27, 2021 |

Secondary offering

On October 14, 2021, Cenovus closed a $227.5 million bought deal secondary offering of the Company's common shares. Post-closing of the offering, Cenovus no longer holds any of Headwater's common shares and as a result, the investor agreement (the "Investor Agreement") between Cenovus and Headwater was terminated in accordance with its terms. In connection with the termination of the Investor Agreement, one of Cenovus' nominees on the Board of Directors of the Company resigned. The other nominee of Cenovus on the Board of Directors of the Company will continue to serve as a director of the Company notwithstanding the termination of the Investor Agreement. Headwater did not receive any proceeds of the secondary offering. Cenovus continues to hold 15,000,000 Cenovus Warrants exercisable at $2.00 per common share until December 2, 2023.

## Non-IFRS Financial Measures

Throughout this MD&A, the Company uses the terms "operating cash flow", "adjusted funds flow from operations", "adjusted net income (loss)" and "adjusted working capital". These terms do not have any standardized meaning as prescribed by IFRS and, therefore, may not be comparable with the calculation of similar measures presented by other issuers.

Operating cash flow is a measure of a company's efficiency and its ability to fund future capital expenditures. Operating cash flow is calculated as sales plus realized gains or losses on financial derivatives, less royalties, blending and transportation expense and production expense, as follows:

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2021 | 2020 | 2021 | 2020 |
| | *(thousands of dollars)* | | *(thousands of dollars)* | |
| Sales | 50,123 | - | 115,653 | 2,873 |
| Realized gain (loss) on financial derivatives | - | - | (405) | 3,937 |
| Royalties | (7,323) | - | (15,029) | (72) |
| Blending and transportation | (7,360) | - | (19,898) | - |
| Production expense | (3,099) | (519) | (8,472) | (1,700) |
| Operating cash flow | 32,341 | (519) | 71,849 | 5,038 |

Adjusted funds flow from operations is used by the Company to analyze operating performance. Adjusted funds flow from operations is defined as cash flows from operating activities before changes in non-cash working capital and transaction costs, as follows:

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2021 | 2020 | 2021 | 2020 |
| | *(thousands of dollars)* | | *(thousands of dollars)* | |
| Cash flow provided by operating activities | 27,888 | (364) | 63,903 | 1,681 |
| Changes in non–cash working capital | 3,636 | (473) | 5,282 | (2,097) |
| Transaction costs | - | - | - | 4,382 |
| Adjusted funds flow from operations | 31,524 | (837) | 69,185 | 3,966 |

The Company utilizes adjusted net income (loss) as a measure of financial performance that is more comparable between periods. Adjusted net income (loss) is defined as net income (loss) before remeasurement loss on the warrant liability, as follows:

| | Three months ended September 30, | | Nine months ended September 30, | |
|---|---|---|---|---|
| | 2021 | 2020 | 2021 | 2020 |
| | *(thousands of dollars)* | | *(thousands of dollars)* | |
| Net income (loss) | 26,106 | (1,723) | 17,901 | (10,212) |
| Remeasurement loss on warrant liability | 2,762 | - | 27,930 | - |
| Adjusted net income (loss) | 28,868 | (1,723) | 45,831 | (10,212) |

Adjusted working capital is used by the Company to measure liquidity. Adjusted working capital is defined as working capital excluding the effects of the Company's financial derivatives receivable/liability and warrant liability, as follows:

| | As at September 30, 2021 | As at December 31, 2020 |
|---|---|---|
| | *(thousands of dollars)* | |
| Working capital | 16,490 | 70,528 |
| Financial derivatives receivable | - | (74) |
| Financial derivatives liability | 8,984 | - |
| Warrant liability | 38,235 | 10,305 |
| Adjusted working capital | 63,709 | 80,759 |

## Operating Metrics

Operating metrics including operating netback, adjusted funds flow netback, adjusted net income (loss) per boe, net income (loss) per boe, adjusted net income (loss) per share and adjusted funds flow per share are metrics used in the oil and gas industry and are used by management to better analyze the Company's performance against prior periods on a comparable basis. These metrics have no equivalent IFRS measure and are therefore excluded from the discussion under "Non-IFRS Financial Measures". They also may not be comparable with the calculation of similar measures presented by other issuers.

Operating netback and adjusted funds flow netback are presented as operating cash flow and adjusted funds flow from operations on a per boe basis. Volumes used to calculate these netbacks include unblended heavy crude oil sales volumes in addition to sales volumes for natural gas and natural gas liquids. Adjusted funds flow per share is calculated as adjusted funds flow from operations divided by the number of weighted average basic or diluted shares outstanding during the period. See the table under the heading "Net Income (Loss), Adjusted Net Income (Loss) and Adjusted Funds Flow from Operations" in this MD&A for additional details on how each of these metrics has been calculated.

## Disclosure Controls and Procedures

The Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures as defined in National Instrument 52-109 of the Canadian Securities Administrators, to provide reasonable assurance that (i) material information relating to the Company is made known to the Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared and (ii) information required to be disclosed by the Company in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

## Internal Controls over Financial Reporting

The Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal controls over financial reporting as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

The Company confirms that there were no changes to Headwater's internal controls over financial reporting during the interim period from July 1, 2021 to September 30, 2021, that have materially affected, or are reasonably likely to affect, the Company's internal control over financial reporting.

It should be noted that while Headwater's Chief Executive Officer and Chief Financial Officer believe that the Company's internal controls and procedures provide a reasonable level of assurance and that they are effective, they do not expect that these controls will prevent all errors or fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met.

## Critical Accounting Estimates

Use of estimates and judgments

The preparation of the Company's financial statements in accordance with IFRS requires management to make estimates and assumptions that affect the reported amount of assets and liabilities and disclosure of contingent liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Such estimates and assumptions are evaluated at each reporting date and are based on management's experience and other factors, including expectations of future events that are believed to be reasonable under the circumstances. Actual results may differ from the estimated amounts as future confirming events occur and more information is obtained by management. The Company has identified the following areas requiring significant judgments, assumptions or estimates.

*Impact of COVID-19*

In March 2020, the World Health Organization declared a global pandemic following the emergence and rapid spread of a novel strain of the coronavirus ("COVID-19"). The outbreak and subsequent measures enforced to limit the spread of the pandemic contributed to volatility in financial markets. The pandemic has adversely impacted global commercial activity, including significantly reducing worldwide demand for crude oil and natural gas.

The full extent of the impact of COVID-19 on the Company's operations and future financial performance, including the recoverable amounts of its exploration and evaluation assets and property, plant and equipment, is currently unknown. It will depend on future developments that are uncertain and unpredictable, including the duration and spread of COVID-19, the global roll-out of a vaccine and the virus' continued impact on financial markets.

The outbreak and current market conditions have increased the complexity of estimates and assumptions used to prepare financial statements, particularly related to recoverable amounts. There is a high degree of uncertainty regarding the estimates and assumptions used in determining the recoverable amounts including future crude oil and natural gas commodity prices, foreign exchange rates, discount rates and the Company's future crude oil and natural gas production. As the understanding of the longer-term impacts of COVID-19 develops, the estimates and assumptions used in determining the recoverable amounts could change and there could be a material financial impact in future periods.

*Alternative Sources of Energy*

The Company has considered the impacts of climate change and the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels in its assessment of impairment of its oil and gas properties. The measurement of impairment for the Company's oil and gas properties, when required, is based on proved plus probable reserves where the majority of the cash flows incorporated into the estimate of the recoverable amount are estimated to be realized in the next ten years. A specific adjustment to the recoverable amount to account for the risk of climate change was not considered necessary for the impairment tests completed to date, however, the recoverable amount was based on an estimated period of cash flows that indirectly reflects changing energy demands and the discount rate applied in the impairment test incorporated the cost of capital in the energy industry which indirectly reflected market trends around climate change. The ultimate period in which global energy markets can transition from carbon-based sources to alternative energy is highly uncertain.

*a)* Critical Judgments in Applying Accounting Policies

*Business Combinations*

Business combinations are accounted for using the acquisition method of accounting. The determination of fair value is estimated based on information available at the date of acquisition and requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of exploration and evaluation assets and property, plant and equipment acquired generally require the most judgment and include estimates of the cash flows associated with proved and probable reserves acquired which is impacted by assumptions related to forecasted production, forecasted operating and royalty costs, future development costs, future crude oil and natural gas commodity prices, foreign exchange rates, and discount rates. Assumptions are also required to determine the fair value of decommissioning liabilities associated with the properties. Changes in any of these assumptions or estimates used in determining the fair value of acquired assets and liabilities could impact the amounts assigned to assets, liabilities (including deferred income tax liabilities) in the acquisition equation. Future net income (loss) will be affected as the fair value on initial recognition impacts future depletion expense, as well as the risk of potential impairment in future periods.

*Determination of cash-generating units ("CGU") and impairment*

The determination of what constitutes a CGU used to test the recoverability of the carrying values of the Company's oil and gas properties is subject to management's judgment. Judgments are made in regard to shared infrastructure, geographical proximity, petroleum type and similar exposure to market risks and materiality. The asset composition of a CGU can directly impact the recoverability of the assets included therein.

Judgments are required to assess when impairment or impairment reversal indicators exist and impairment testing is required.

The Company's CGUs as at September 30, 2021 include its New Brunswick CGU consisting of its McCully assets and its Alberta CGU comprised of its Marten Hills assets.

*Exploration and evaluation ("E&E") assets*

The application of the Company's accounting policy for E&E assets requires management to make certain judgments as to whether economic quantities of reserves have been found. Judgment is also required to determine the level at which E&E is assessed for impairment; for Headwater, the recoverable amount of E&E assets is assessed at a CGU level.

*Deferred income taxes*

Judgment is required to assess the recognition of deferred income tax assets which is based on the probability that future taxable profits will be sufficient to utilize the underlying taxable amounts. Changes in the estimated future taxable profits, which is based on the cash flows associated with the Company's proved reserves, could materially impact the Company's deferred income tax assets recognized.

*b)* Key Sources of Estimation Uncertainty

*Recoverability of asset carrying value and valuation of reserves*

At each reporting date, the Company assesses its property, plant and equipment and exploration and evaluation assets to determine if there is any indication that the carrying amount of the assets may not be recoverable. An assessment is also made at each reporting date to determine whether there is any indication that previously recognized impairment losses no longer exist or have decreased. Determination as to whether and how much an asset is impaired, or no longer impaired, involves management's estimates on highly uncertain matters. The key estimates used in the determination of cash flows from crude oil and natural gas reserves include the following:

i) Reserves and forecasted production – assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in future price estimates, production levels or results of future drilling may change the economic status of reserves and may ultimately result in reserves revisions.

ii) Forecasted crude oil and natural gas prices – commodity prices can fluctuate for a variety of reasons including supply and demand fundamentals, inventory levels, exchange rates, weather, and economic and geopolitical factors.

iii) Discount rate – the discount rate used to calculate the net present value of cash flows is based on estimates of an approximate industry peer group weighted average cost of capital. Changes in the general economic environment could result in significant changes to this estimate.

iv) Forecasted operating and royalty costs and future development costs – estimates concerning future drilling and infrastructure costs and production costs required to operate the assets are used in the cash flow model.

Changes in circumstances may impact these estimates which could have a material financial impact in future periods.

Reserves estimates also have a material financial impact on depletion expense, property, plant, and equipment acquired in business combinations, deferred income taxes and decommissioning liabilities, all of which could have a material impact on financial results. These reserve estimates are evaluated by third-party reserve evaluators at least annually, who work with information provided by the Company to establish reserve determinations in accordance with National Instrument 51-101, "*Standards of Disclosure for Oil and Gas Activities*". Changes in circumstances may impact these estimates which could have a material financial impact in future periods.

*Decommissioning liabilities*

The decommissioning costs which will ultimately be incurred by the Company are uncertain and estimates can vary in response to many factors including changes to relevant legal requirements, the emergence of new restoration techniques or experience at other production sites. The expected timing can also change in response to changes in reserves or changes in laws and regulations. As a result, there could be significant adjustments to the provisions established which could materially affect future financial results. Judgments include the most appropriate discount rate to use, which management has determined to be a risk-free rate.

*Valuation of financial instruments*

The estimated fair values of the Company's financial derivative commodity contracts are subject to measurement uncertainty due to the estimation of future crude oil and natural gas commodity prices, foreign exchange rates and volatility.

The estimated fair value of the warrant liability, which is considered a financial instrument, uses the Monte Carlo simulation pricing model which is based on assumptions including volatility, risk-free interest rate and the expected term.

*Valuation of Warrants and stock options*

The estimated fair values of the Recapitalization Warrants issued as part of the non-brokered private placement in connection with the Recapitalization Transaction and stock options issued under the Company's stock option plans were based on the Black-Scholes pricing model incorporating assumptions on volatility, risk-free interest rate, forfeiture rate and the expected term.

## Business Conditions and Risks

There are numerous factors both known and unknown, that could cause actual results or events to differ materially from forecast results. The following is a summary of such risk factors, which should not be construed as exhaustive:

- Public health risks including relating to the COVID-19 pandemic may affect the Company's results, business, financial conditions or liquidity;
- Natural disasters, terrorist acts, civil unrest, pandemics and other disruptions and dislocations may affect the Company's results, business, financial conditions or liquidity;
- Weakness and volatility in the market conditions for the oil and natural gas industry may affect the value of the Company's reserves and restrict its cash flow and ability to access capital to fund the development of it properties;
- Current and any new regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes, adversely affecting the Company's financial position;
- Various factors may adversely impact the marketability of oil and natural gas, affecting net production revenue, production volumes and development and exploration activities;
- The anticipated benefits of acquisitions may not be achieved and the Company may dispose of non-core assets for less than their carrying value on the financial statements as a result of weak market conditions;
- The Company's business may be adversely affected by recent political and social events and decisions made in Canada, the United States, Europe and elsewhere;
- Lack of capacity and/or regulatory constraints on gathering and processing facilities and pipeline systems may have a negative impact on the Company's ability to produce and sell its oil and natural gas;
- The Company competes with other oil and natural gas companies, some of which have greater financial and operational resources;
- The Company's ability to successfully implement new technologies into its operations in a timely and efficient manner will affect its ability to compete;
- Changes to the demand for oil and natural gas products and the rise of petroleum alternatives may negatively affect the Company's financial condition, results of operations and cash flow;
- Modification to current, or implementation of additional, regulations (including environmental regimes) or royalty regimes may reduce the demand for oil and natural gas, impact the Company's cash flows and/or increase the Company's costs and/or delay planned operations;
- Taxes on carbon emissions affect the demand for oil and natural gas, the Company's operating expenses and may impair the Company's ability to compete;
- Liability management programs enacted by regulators in the western provinces may prevent or interfere with the Company's ability to acquire properties or require a substantial cash deposit with the regulator;
- The Company may require additional financing, from time to time, to fund the acquisition, exploration and development of properties and its ability to obtain such financing in a timely fashion and on acceptable terms may be negatively impacted by the current economic and global market volatility;
- Changing investor sentiment towards the oil and natural gas industry may impact the Company's access to, and cost of capital;
- Oil and natural gas operations are subject to seasonal weather conditions and, if applicable to the Company's operations in the future, the Company may experience significant operational delays as a result;
- Regulatory water use restrictions and/or limited access to water or other fluids may impact the Company's future production volumes from any future waterflood of the Company;
- Credit risk related to non-payment for sales contracts or other counterparties;
- Foreign exchange risk as commodity sales are based on US dollar denominated benchmarks; and

- The risk of significant interruption or failure of the Company's information technology systems and related data and control systems or a significant breach that could adversely affect the Company's operations.

Additional risks and information on risk factors are included in the Annual Informational Form for the year ended December 31, 2020, dated March 10, 2021, which is available on the Company's website at www.headwaterexp.com and under the Company's profile on SEDAR at www.sedar.com.

The Company uses a variety of means to help mitigate or minimize these risks including the following:

- Attracting and retaining a team of highly qualified and motivated professionals who have a vested interest in the success of the Company;
- Employing risk management instruments to minimize exposure to volatility of commodity prices;
- Maintaining a strong financial position;
- Maintaining strict environmental, safety and health practices;
- Maintaining a comprehensive insurance program;
- Managing credit risk by entering into agreements with counterparties that are investment grade; and
- Implementation of cyber security protocols and procedures to reduce to risk of failure of breach of data.

## Oil and Gas Metrics

Barrels of Oil Equivalent

The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. Per boe amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil. This equivalence is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil 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.

## Forward Looking Information

This MD&A contains certain forward-looking statements and forward-looking information (collectively referred to herein as "forward-looking statements") within the meaning of Canadian securities laws. All statements other than statements of historical fact are forward-looking statements. Forward-looking information typically contains statements with words such as "anticipate", "believe", "plan", "continuous", "estimate", "expect", "may", "will", "project", "should" or similar words suggesting future outcomes. In particular, this MD&A contains forward-looking statements pertaining to the following:

- business plans and strategies (including its production optimization and hedging strategies);
- the expected timing for commissioning of the Company's oil processing facility;
- the expectation that transportation costs will decrease to approximately $3.50 per boe after commissioning of the Company's oil processing facility;
- the expectation that the annual weighted average discount to WCS is approximately $2.00/bbl;
- the expected timing for resumption of production from the Company's McCully assets;
- the expected percentage of the production from the McCully field to be covered by hedges;

- the expectation that the Company will have adequate liquidity to fund its 2021 capital expenditure budget of $140 million and contractual obligations in the near term through existing working capital and forecasted cash flows from operations;
- the expectation that Headwater could make use of additional equity or debt financings to fund future acquisitions;
- revised 2021 guidance including annual average daily production, fourth quarter 2021 daily production, exit adjusted working capital and capital expenditures;
- 2022 approved budget and guidance including annual average daily production, fourth quarter 2022 daily production, exit adjusted working capital, capital expenditures and adjusted funds flow from operations;
- expectation of converting certain crude oil wells to injection wells for waterflood implementation
- expected operations on the Company's current properties;
- Canadian – U.S. dollar exchange rate;
- expected natural gas sales prices and premiums;
- future revenue from financial hedges;
- the Company's tax pools and ability to use such tax assets in the future;
- the expectation that the Company has sufficient financial resources to fund its expected operations;
- the expectation that the Company has sufficient available funds to meet the Company's current and foreseeable contractual obligations;
- the expected effects of certain accounting changes;
- the expected sources to finance future acquisitions; and
- expected future decommissioning liabilities.

Statements relating to "reserves" are forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves described, as applicable, exist in the quantities predicted or estimated and can profitably be produced in the future.

Undue reliance should not be placed on forward-looking statements, which are inherently uncertain, are based on estimates and assumptions, and are subject to known and unknown risks and uncertainties (both general and specific) that contribute to the possibility that the future events or circumstances contemplated by the forward-looking statements will not occur. There can be no assurance that the plans, intentions or expectations upon which forward-looking statements are based, will in fact be realized. Actual results will differ, and the difference may be material and adverse to the Company and its shareholders.

The forward-looking statements contained herein are based on certain key expectations and assumptions made by the Company, including but not limited to expectations and assumptions concerning the success of optimization and efficiency improvement projects, the availability of capital, current legislation, receipt of required regulatory approval, the success of future drilling, development and waterflooding activities, the performance of existing wells, the performance of new wells, Headwater's growth strategy, general economic conditions, availability of required equipment and services, prevailing equipment and services costs and prevailing commodity prices. Although the Company believes that the expectations and assumptions on which the forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because the Company can give no assurance that they will prove to be correct.

Any financial outlook or future oriented financial information in this MD&A as defined by applicable securities legislation, has been approved by management of the Company as of the date hereof. Readers are cautioned that any such future-oriented financial information contained herein should not be used for purposes other than those for which it is disclosed herein. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, risks associated with the oil and gas industry in general (e.g., operational risks in development, exploration and production; disruptions to the Canadian and global economy resulting from major public health events, including the COVID-19 pandemic, war, terrorist events, political upheavals and other similar events; events impacting the supply and demand for oil and gas including the COVID-19 pandemic and actions taken by the OPEC + group; delays or changes in plans with respect to exploration or development projects or capital expenditures relating to, among other things, restrictions on activities resulting from the COVID-19 pandemic; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, the uncertainty associated with exploration and development projects, including waterfloods, costs and expenses, and health, safety and environmental risks, commodity price and exchange rate fluctuations; changes in legislation affecting the oil and gas industry and uncertainties resulting from potential delays or changes in plans with respect to exploration or development projects or capital expenditures), trading of common shares, seasonality, disclosure controls and procedures and internal controls over financial reporting, competition, conflicts of interest, issuance of debt, title to properties, hedging, information systems, litigation, and aboriginal land and rights claims. Further information regarding these factors and additional factors may be found under the heading "Risk Factors" in the Annual Informational Form for the year ended December 31, 2020, dated March 10, 2021, which is available on the Company's website at www.headwaterexp.com and under the Company's profile on SEDAR at www.sedar.com. Readers are cautioned that the foregoing list of factors that may affect future results is not exhaustive.

The forward-looking statements contained in this MD&A are made as of the date hereof and the Company does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, except as required by applicable law. The forward-looking statements contained herein are expressly qualified by this cautionary statement.

## Corporate Information

### Board of Directors

NEIL ROSZELL
Executive Chairman & CEO, Headwater Exploration Inc.
Calgary, Alberta

JASON JASKELA
President and COO, Headwater Exploration Inc.
Calgary, Alberta

CHANDRA HENRY (1) (2)
CFO and Chief Compliance Officer, Longbow Capital Inc.
and Director, Bonavista Energy Corp.
Calgary, Alberta

STEPHEN LARKE (2)
Director, Vermillion Energy Inc. and Topaz Energy Corp.
Calgary, Alberta

PHILLIP KNOLL(3)
Director, Altagas Ltd.
Calgary, Alberta

KEVIN OLSON (1) (3)
Independent Businessman
Calgary, Alberta

DAVE PEARCE (2) (3)
Deputy Managing Partner, Azimuth Capital Management
and Direcor, Baytex Energy Corp.
Calgary, Alberta

KAM SANDHAR (1)
Executive Vice-President, Strategy & Corporate Development
Cenovus Energy Inc.

### Officers

NEIL ROSZELL, P. Eng.
Executive Chairman & CEO

JASON JASKELA, P. Eng.
President and COO

ALI HORVATH, CPA, CA
Vice President Finance & CFO

TERRY DANKU, P. Eng.
Vice President Engineering

JON GRIMWOOD, P. Geo.
Vice President Exploration

SCOTT RIDEOUT
Vice President Land

BRAD CHRISTMAN
Vice President Production

TED BROWN (Corporate Secretary)
Burnet, Duckworth & Palmer LLP

(1) Audit Committee
(2) Corporate Governance and Sustainability Committee
(3) Reserves Committee

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**Auditors**
KPMG LLP
Calgary, Alberta

**Independent Reservoir Consultants**
GLJ Ltd.