

September 14, 2026

PRESIDENT'S MESSAGE

North 40 Resources Ltd. is pleased to report its operating and financial results for the three and six months ended June 30, 2026.

Highlights for this period include:

- Q2 2026 production averaged 5,969 boe/day (55% oil and liquids), which is a 14% decrease from Q1 2026 average of 6,934 boe/day (51% oil and liquids). Production for the first six months of 2026 averaged 6,449 boe/day (53% oil and liquids). On March 31, 2026, the Company shut in 900-1000 boe/day of production due to low gas prices.
- Revenue in Q2 2026 increased to \$36.4 million from \$29.1 million in Q1 2026.
- Operating netbacks were \$34.42/boe and \$27.74/boe for the quarter and first half of 2026, respectively.
- Invested \$8.2 million in capital spending in the quarter and \$31.3 million in the first half. Capital in Q2 2026 included the drilling of two wells and the completion of natural gas infrastructure, which commenced in Q1 2026. The infrastructure project, which rerouted natural gas away from third party facilities to North 40 owned infrastructure was operational midway in Q2.

Q2 to Q4 2026 Activity

North 40 drilling activity in Q2 2026 was comprised of the drilling of one 6 leg multi-lateral Glauconitic appraisal well at Matziwin South and one horizontal Ellerslie appraisal well at Aerial West. Both wells are on production.

To date in Q3 2026, North 40 has drilled a total of six horizontal wells comprised of appraisal and development wells amongst the Aerial West, Wayne and Drumheller properties. North 40 expects all Q3 2026 wells to be brought on production by the end of Q3.

Last week at Matziwin South, North 40 spud the first well of a two well 6 leg multi lateral Glauconitic delineation program, building on our Q2 2026 drilling success.

To date in 2026, a total of twelve wells have been drilled and one well at Matziwin South is drilling.

North 40 expects to drill an additional four to six wells in Q4 2026 and all wells will be brought on production in Q4 2026.

At Wayne, an enhanced recovery waterflood pilot has been initiated and we expect the pilot to be operational in Q4 2026.

In Q1 2027, an enhanced recovery waterflood pilot will likely be implemented at Matziwin South.

Results from the North 40 2025 drilling program at Michichi fell short of our expectations and drilling will be deferred at Michichi until such time that North 40 determines the best practises to develop this large four to six section pool. North 40 expects our learnings at Aerial West will aid in the approach to further development Michichi.

In the Greater Sheerness area, a sixteen well recompletion program was initiated in 2026. The program is largely focused on testing Mannville targets for high liquid gas production. Liquid yields in the Mannville range from 20 to 30 bbl/MMcf. Five wells from the Mannville program have been selected for fracture stimulation to assess the deliverability capability of the Mannville horizons. This program is expected to be complete by the end of October 2026.

The Board of Directors has approved a 2026 capital budget of \$ 80.3 million, net of third-party funding proceeds.

North 40 expects production in Q4 2026 to average 4,500 bbls/day of oil and liquids and 24 MMcf/d of natural gas or 8,500 boe/day (54% oil and liquids).

As always, we appreciate and thank you for your support. Please feel free to contact myself or Kim Schoenroth with any questions or comments you may have.

Sincerely,

NORTH 40 RESOURCES LTD.

Don W Robson
President & CEO

NORTH 40

RESOURCES LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following analysis was prepared as at September 14, 2026 and should be read in conjunction with North 40 Resources Ltd.'s ("North 40" or "the Company") audited financial statements and the accompanying notes for the year ended December 31, 2025 and the unaudited condensed interim financial statements for the three and six months ended June 30, 2026, which have been prepared in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IFRS" or "GAAP").

Basis of Presentation – The reporting and measurement currency is the Canadian dollar. For the purposes of calculating unit costs, natural gas is converted to a barrel of oil equivalent ("boe") using six thousand cubic feet of natural gas equal to one barrel of oil unless otherwise stated.

Forward-Looking Statements – Certain information set forth in this document, including management's assessment of North 40's future plans for capital expenditures and expectations for production rates, prices and operating results, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond North 40's control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. North 40's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements.

Non-IFRS Measurements – Within Management's Discussion and Analysis, references are made to terms commonly used in the oil and gas industry. This document contains "funds flow from operations" which is a non-IFRS financial measure. This document also contains the terms "operating netback", "working capital surplus (deficiency)", and capital expenditures which are non-IFRS financial measures. These non-IFRS terms do not have any standardized meaning prescribed by IFRS and therefore it may not be comparable with the calculation of similar measures for other entities.

Funds flow from operations

Management uses funds flow from operations to evaluate performance. Funds flow from operations as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities. Funds flow from operations per share is calculated based on the weighted average number of shares outstanding consistent with the calculation of net income or loss per share. Total boe is calculated by multiplying the daily production by the number of days in the period.

The following table reconciles funds flow from operations to cash provided by operating activities, which is the most directly comparable measure calculated in accordance with IFRS.

(thousands)	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Cash provided by (used in) operating activities	\$16,394	\$13,467	\$26,190	\$34,084
Plus: Net change in non-cash working capital	1,551	(341)	3,567	(517)
Funds flow from operations	\$17,945	\$13,126	\$29,757	\$33,567

Operating netback

Management uses operating netbacks as a profitability measure relative to current commodity prices. Operating netback is calculated as the weighted average sales price of all its commodities less royalties, operating and transportation expenses. There are no IFRS measures that are reasonably comparable to operating netbacks.

Working capital surplus (deficiency)

Working capital surplus (deficiency) is the total of current assets less current liabilities. This measure is used to assess efficiency, liquidity and general financial strength of the Company.

(thousands)	Six months ended June 30	
	2026	2025
Cash	\$22	\$ -
Accounts Receivable	12,970	10,184
Current income taxes	-	759
Prepays and Deposits	1,187	1,391
Assets held-for-sale	-	300
Current Assets	\$14,179	\$12,634
Accounts payable and accrued liabilities	\$15,801	\$23,684
Current income taxes	775	-
Decommissioning obligations	435	-
Bank debt	7,625	1,779
Current Liabilities	\$24,636	\$25,463
Working capital deficiency	\$10,457	\$12,829

Capital Expenditures

Capital expenditures are the sum of exploration and evaluation, and property and equipment expenditures, and acquisitions disclosed in the Statements of Cash Flow.

(thousands)	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Exploration and evaluation expenditures	\$2,168	\$3,400	\$7,289	\$4,211
Property, plant and equipment expenditures	6,028	13,153	20,405	34,927
Acquisitions	-	-	3,615	12,392
Capital expenditures	\$8,196	\$16,553	\$31,309	\$51,530

(thousands, except per unit amounts and where indicated)	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
FINANCIAL				
Petroleum and natural gas revenue	\$36,420	\$29,818	\$65,553	\$68,413
Funds flow from operations ⁽¹⁾	\$17,945	\$13,126	\$29,757	\$33,567
Per share – basic	\$0.23	\$0.17	\$0.38	\$0.44
Per share – diluted	\$0.21	\$0.15	\$0.35	\$0.39
Net income (loss)	\$7,086	\$(8,210)	\$5,139	\$(2,455)
Per share – basic	\$0.09	\$(0.11)	\$0.06	\$(0.03)
Per share – diluted	\$0.08	\$(0.11)	\$0.06	\$(0.03)
Capital expenditures ⁽²⁾	\$8,196	\$16,553	\$31,309	\$51,530
Working capital deficiency ⁽³⁾ at end of period	\$10,457	\$12,829	\$10,457	\$12,829
Common shares outstanding at end of period	77,844	77,612	77,844	77,612
OPERATING				
Sales volumes				
Oil and liquids (bbls/day)	3,280	4,135	3,399	4,443
Natural gas (mcf/day)	16,131	18,662	18,297	17,453
Total (boe/day) ⁽⁴⁾	5,969	7,245	6,449	7,352
% Oil and liquids	55	57	53	60
Commodity prices realized (before pipeline tariffs)				
Oil and liquids (\$/bbl)	116.99	74.94	99.84	80.74
Natural gas (\$/mcf)	1.84	1.91	2.06	2.17
Total (\$/boe)	69.28	47.69	58.47	53.93
Operating netback (\$/boe) ⁽⁵⁾	34.42	23.07	27.74	27.89
Funds flow from operations netback (\$/boe) ⁽¹⁾	33.04	19.91	25.49	25.23
Net wells drilled	2.0	5.0	6.0	11.0
Net acres of land at end of period	306,217	266,003	306,217	266,003

⁽¹⁾ Funds flow from operations and funds flow from operations netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽²⁾ Capital expenditures does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽³⁾ Working capital surplus (deficiency) does not have a standardized measure prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽⁴⁾ Boe conversion is 6:1

⁽⁵⁾ Operating netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

PRODUCTION

	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Oil (bbls per day)	2,791	3,555	2,863	3,900
Liquids (bbls per day)	490	580	536	543
Natural gas (mcf per day)	16,131	18,662	18,297	17,453
BOE per day	5,969	7,245	6,449	7,352

Production in Q2 2026 averaged 5,969 boe per day (55% oil and liquids), an 18% decrease from the Q2 2025 average of 7,245 boe per day (57% oil and liquids). Production for the first six months of 2026 averaged 6,449 boe per day (53% oil and liquids) compared to 7,352 boe per day (60% oil and liquids) in the same period of 2025. Contributing to the Q2 2026 decrease in production compared to Q2 2025 are additions from fewer wells drilled and brought on production in the first half of 2026, as well as natural expected declines.

Two wells were drilled in Q2 2026, with one of these wells brought on production at the end of June. Five wells were drilled in Q2 2025, with one well at Wayne brought on production late in June.

Oil and liquids production decreased 21% to 3,280 bbls per day in Q2 2026 from 4,135 bbls per day in Q2 2025 and decreased 23% to 3,399 bbls per day in the first six months of 2026 from 4,443 bbls per day in the comparable 2025 period. Contributing to the first half 2026 decrease in production compared to the first half 2025 are additions from fewer wells drilled and brought on production in the first half of 2026 as well as natural expected declines.

Natural gas production decreased 14% to 16,131 mcf per day in Q2 2026 from 18,662 mcf per day in Q2 2025. Production in the first six months of 2026 averaged 18,297 mcf per day, which is a 5% increase from the 17,453 mcf per day in the same period of 2025. Production changes are from the same factors for oil and liquids, as well the Company had shut-in some natural gas production during the second quarter of 2026.

At the beginning of Q2 2026, the Company shut-in approximately 950 boe per day (about 5,100 mcf per day of natural gas) of production from natural gas wells processed at third party facilities due to low natural gas price realizations.

OPERATING NETBACK

	Three months ended June 30		Six months ended June 30	
(\$ per BOE)	2026	2025	2026	2025
Revenue ⁽¹⁾	\$67.05	\$45.22	\$56.16	\$51.40
Royalties	(14.54)	(9.55)	(11.77)	(10.32)
Operating expenses	(15.98)	(10.50)	(14.78)	(11.03)
Transportation expenses	(2.11)	(2.10)	(1.87)	(2.16)
Operating netback ⁽²⁾	\$34.42	\$23.07	\$27.74	\$27.89

⁽¹⁾ Net of pipeline tariff amount of \$2.22 and \$2.30 per boe for the three and six months ended June 30, 2026, and \$2.47 and \$2.53 per boe in the comparable periods of 2025, respectively.

⁽²⁾ Operating netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

The operating netback was higher in Q2 2026 compared to the same period in 2025 primarily due to higher realized prices for crude oil, partially offset by higher royalties and operating expenses.

The operating netback was slightly lower in the first six months of 2026 compared to the same period in 2025 primarily due to higher royalty and operating expenses, partially offset by higher realized prices for crude oil and lower transportation expenses.

COMMODITY PRICES

	Three months ended June 30		Six months ended June 30	
(\$ per bbl)	2026	2025	2026	2025
WTI (US\$/bbl)	\$92.79	\$64.15	\$82.36	\$67.79
MSW benchmark price ⁽¹⁾	\$136.88	\$84.86	\$112.68	\$90.14
WCS benchmark price ⁽²⁾	\$108.10	\$74.58	\$93.67	\$79.48
Realized crude oil price	\$124.72	\$80.13	\$106.76	\$85.34

⁽¹⁾ Mixed sweet blend (MSW) is the benchmark conventionally produced light sweet crude for Western Canada. It is often referenced as Edmonton Par Crude.

⁽²⁾ Western Canadian Select (WCS) is a Hardisty based blend of conventional and oil sands production. WCS is a heavy sour blend of crude oil.

North 40's realized crude oil price reflects 27° API and differentials are typically close to the average of the MSW and WCS benchmark differentials.

North 40's realized crude oil price (before pipeline tariffs) in Q2 2026 was \$124.72 per barrel which is 56% higher than the Q2 2025 price of \$80.13 per barrel. WTI benchmark prices increased 45% to \$92.79 from \$64.15 per barrel in Q2 2025 contributing most to the increase in North 40's realized price. Also contributing to the increase in the Company's realized oil price was stronger MSW differentials partially offset by wider WCS differentials. The WCS differential widened to average US\$14.66 per barrel in Q2 2026 from US\$10.27 per barrel in Q2 2025. The MSW differential narrowed to average a premium of US\$2.52 per barrel in Q2 2026 compared to US\$2.84 per barrel in Q2 2025.

North 40's realized oil price increased 25% in the first half of 2026 to \$106.76 per barrel from \$85.34 per barrel realized in the first half of 2025 due to a 21% increase in WTI benchmark prices and stronger MSW differentials partially offset by wider WCS differentials and a stronger Canadian dollar. The WCS differential widened to average US\$14.41 per barrel in the first half of 2026 from US\$11.47 per barrel in the same period of 2025. The MSW differential narrowed to average US\$0.62 per barrel in the first six months of 2026 compared to US\$3.91 per barrel in the same period of 2025.

The Canadian dollar was mostly unchanged averaging \$1.3838 in Q2 2026 compared to \$1.3841 in Q2 2025. The Canadian dollar strengthened to average \$1.3776 in the first six months of 2026 compared to \$1.4102 in the same period of 2025.

The WTI price substantially increased beginning late in the first quarter of 2026 due to global geopolitical conflicts.

	Three months ended June 30		Six months ended June 30	
(\$ per mcf)	2026	2025	2026	2025
AECO Daily (5A) index	\$1.63	\$1.69	\$1.82	\$1.93
Realized natural gas price	\$1.84	\$1.91	\$2.06	\$2.17

North 40's natural gas production is sold at the AECO daily 5A index and realizes a slightly better price than the index due to its higher-than-standard heat content. North 40's realized price decreased 4% to \$1.84 per mcf in Q2 2026 from \$1.91 per mcf in Q2 2025 and decreased 5% to \$2.06 per mcf for the first six months of 2026 from \$2.17 per mcf in the same period of 2025.

REVENUE

(\$ thousands)	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Oil and liquids	\$34,141	\$27,132	\$59,773	\$62,634
Natural gas	2,279	2,686	5,780	5,779
Petroleum and natural gas revenue	\$36,420	\$29,818	\$65,553	\$68,413
% Oil and liquids	94	91	91	92

Note: Petroleum and natural gas revenue presented in the Statements of Income and Comprehensive Income is net of pipeline tariffs.

Revenue in Q2 2026 increased to \$36.4 million from \$29.8 million in Q2 2025. The increase is due to higher realized oil and liquids prices partially offset by lower production volume of all products.

Revenue for the six months ended June 30 decreased by 4% from \$68.4 million in 2025 to \$65.6 million in 2026. The decrease is due to lower crude oil production volume partially offset by higher realized oil and liquids prices.

Oil and liquids revenue represents 94% of total revenue in Q2 2026 and increased 26% from \$27.1 million in Q2 2025 to \$34.1 million in Q2 2026. Crude oil realizations were 56% higher and oil production volumes were 21% lower in Q2 2026 compared to the same quarter last year.

Oil and liquids revenue represents 91% of total revenue in first half of 2026 and decreased 5% from \$62.6 million in the first half of 2025 to \$59.8 million in the comparable period of 2026. Crude oil realizations were 25% higher and oil production volumes were 27% lower in the first half of 2026 compared to the same period last year.

Natural gas revenue decreased 15% in Q2 2026 from \$2.7 million in Q2 2025 to \$2.3 million. The decrease is due to a 4% decrease in price realizations and a 14% decrease in production volume in Q2 2026 compared to Q2 2025.

Natural gas revenue was unchanged in the first half of 2026 at \$5.8 million compared to the first half of 2025. The increase in production volume was offset by the decline in natural gas price realizations.

Oil pipeline tariffs of \$0.8 million and \$1.6 million are included in revenue for the second quarter and the first six months of 2026 respectively. This compares to \$1.1 million and \$2.3 million in the same periods of 2025. The custody transfer to the purchaser is at the point the oil is offloaded at the terminal. Gas pipeline tariffs of \$0.4 million and \$1.0 million are also included in revenue for the three months and six months ended June 30, 2026, respectively. This compares to \$0.6 million and \$1.1 million in the same periods of 2025. The custody transfer to the purchaser is at the point the natural gas enters the receipt meter.

ROYALTIES

(thousands, except per unit amounts)	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Royalties	\$7,896	\$6,299	\$13,737	\$13,730
Per BOE	\$14.54	\$9.55	\$11.77	\$10.32
% of Revenue before pipeline tariffs	21%	20%	20%	19%

Royalties will fluctuate with commodity prices and production rates and are determined primarily by the terms of the mineral rights owner agreements and the Alberta provincial government royalty regime.

Royalties increased to \$14.54 per boe, or \$7.9 million, in the second quarter of 2026, compared to \$9.55 per boe, or \$6.3 million, in the second quarter of 2025, reflecting higher realized oil and liquids prices. As a percentage of revenue, royalties increased to 21% from 20%, primarily due to higher Crown royalties on oil and liquids production.

Crown royalties on oil and liquids increased as a result of both higher realized commodity prices and certain wells moving beyond their C* period. During the C* period, Crown royalties are generally levied at a flat rate of 5% until cumulative revenue exceeds the estimated drilling and completion costs of a well. Once this threshold is reached, royalty rates increase with higher commodity prices.

Royalties on a boe basis increased to \$11.77 per boe in the first half of 2026 compared to \$10.32 per boe in the comparable period in 2025 on higher realized oil and liquids prices. Royalties were \$13.7 million in the first half of both periods as the impact of higher oil and liquids prices was offset by lower production volumes.

The majority of the Company's royalties are freehold royalties and freehold mineral tax (which is included in royalties for financial reporting purposes).

OPERATING AND TRANSPORTATION

	Three months ended June 30		Six months ended June 30	
<i>(thousands, except per unit amounts)</i>	2026	2025	2026	2025
Operating expenses	\$8,681	\$6,921	\$17,254	\$14,673
Per BOE	\$15.98	\$10.50	\$14.78	\$11.03
Transportation expenses	\$1,144	\$1,383	\$2,183	\$2,880
Per BOE	\$2.11	\$2.10	\$1.87	\$2.16

Operating expenses averaged \$15.98 per boe and \$14.78 per boe for the second quarter and first six months of 2026, respectively, compared to \$10.50 per boe and \$11.03 per boe in the comparable periods of 2025. Operating expenses increased to \$8.7 million in the second quarter of 2026 from \$6.9 million in the second quarter of 2025 and increased to \$17.3 million in the first six months of 2026 from \$14.7 million in the comparable period of 2025.

The increase in operating expenses reflects North 40's larger operated asset base following acquisitions completed during 2025, including additional pipelines, facilities, and gas processing infrastructure. The primary drivers of the increase were higher surface lease rental costs associated with a larger well and infrastructure footprint, increased maintenance costs related to Company-owned compression, facilities and pipelines, increased well servicing activity associated with a larger and maturing well inventory, and higher property taxes and regulatory costs.

These increases were partially offset by lower water trucking and third-party processing costs. Water trucking costs declined following commissioning of the Michichi disposal well, allowing more produced water to be handled through Company-owned infrastructure rather than third-party facilities. Processing costs also benefited from North 40's ownership interest in gas processing infrastructure acquired in 2025, reducing reliance on third-party processors.

The increase in operating expenses on a per-unit basis reflects both lower production volumes and a larger fixed cost base following North 40's growth through acquisitions and infrastructure ownership. As a result, costs associated with facilities, pipelines, lease rentals, property taxes, maintenance and well servicing are being spread over fewer BOEs than in the comparable 2025 period.

Transportation costs, representing clean oil trucking expenses, averaged \$2.11 per boe in Q2 2026, compared to \$2.10 per boe in Q2 2025. Per boe trucking costs were higher in Q2 2026 due to a greater proportion of oil production being marketed into the MSW stream, which carries higher transportation costs. This was more than offset by improved realized pricing, resulting in a higher netback. The increase in transportation costs on a per boe basis was partially mitigated by oil production comprising a lower percentage of total production.

Transportation costs for the first half of 2026 were \$1.87 per boe compared to \$2.16 per boe in the comparable period of 2025. The decrease is mostly due to oil production being 53% of total production in the first half of 2026 compared to 60% in the first half of 2025.

Transportation costs were \$1.1 million and \$2.2 million in Q2 2026 and for the first half of 2026 compared to \$1.4 million and \$2.9 million in the same periods of 2025 respectively commensurate with lower oil production volumes in 2026.

North 40's crude oil production may be sold in different sales streams in Alberta which may vary month to month depending on the netback at those different streams. As a result, there will be fluctuations in crude oil differentials and transportation costs as the Company seeks out the highest netback opportunity.

OTHER INCOME

	Three months ended June 30		Six months ended June 30	
<i>(thousands, except per unit amounts)</i>	2026	2025	2026	2025
Other income	\$1,160	\$-	\$1,160	\$-
Per BOE	\$2.14	\$-	\$0.99	\$-

The Company sold a portion of its Emission Performance Credits in Q2 2026 for proceeds of \$1.16 million.

GENERAL AND ADMINISTRATIVE

	Three months ended June 30		Six months ended June 30	
<i>(thousands, except per unit amounts)</i>	2026	2025	2026	2025
Gross G&A	\$1,877	\$1,938	\$3,525	\$3,265
Capitalized G&A	(470)	(92)	(997)	(188)
Net G&A	\$1,407	\$1,846	\$2,528	\$3,077
Per BOE	\$2.59	\$2.80	\$2.17	\$2.31

Net general and administrative (“G&A”) expenses were \$1.4 million in Q2 2026 compared to \$1.8 million in Q2 2025. The decrease is mostly attributable to higher capitalized G&A in Q2 2026. Gross G&A decreased slightly as higher costs for consulting and legal costs in Q2 2026 was more than offset by payments related to the exit of the Company’s former Vice President Exploration in Q2 2025.

Net G&A expenses were \$2.5 million in the first half of 2026 compared to \$3.1 million in the same period of 2025. The decrease is mostly attributable to higher capitalized G&A in the first half of Q2 2026. Gross G&A increased as higher costs for consulting, insurance and computer software was partially offset by payments related to the exit of the Company’s former Vice President Exploration in Q2 2025.

On a boe basis, net G&A was \$2.59 and \$2.17 in Q2 and the first half of 2026 respectively compared to \$2.80 and \$2.31 in same periods of 2025. The decrease in the per boe amount is due to lower net G&A expenses in 2026 partially offset by lower production volume when compared to 2025.

Capitalized G&A relates to a portion of the Company’s engineering compensation for 2025. Beginning in Q4 2025, the Company amended its capitalization and overhead recovery policy to industry standard practices. As a result of asset transactions that closed in 2025, the Company’s operations include partners in many wells and infrastructure. Overhead and capital recoveries charged to and by partners are governed by contractual agreements. North 40 has applied the industry standard practice to all its operations.

SHARE-BASED COMPENSATION

	Three months ended June 30		Six months ended June 30	
<i>(thousands, except per unit amounts)</i>	2026	2025	2026	2025
Share-based compensation	\$244	\$103	\$506	\$353
Capitalized share-based compensation	-	(12)	-	(39)
Per BOE	\$0.45	\$0.14	\$0.43	\$0.24

Share-based compensation expense is a non-cash expense and is related to the issuance of Class B and C shares and the grants of options on Class B and C shares to directors, officers, employees, and consultants.

Detailed information regarding the Class B and Class C shares and options have been disclosed in Note 12 of the financial statements.

DEPLETION AND DEPRECIATION

	Three months ended June 30		Six months ended June 30	
<i>(thousands, except per unit amounts)</i>	2026	2025	2026	2025
Depletion and depreciation	\$8,339	\$11,991	\$17,807	\$23,785
Per BOE	\$15.35	\$18.19	\$15.26	\$17.87

The Company recognized depletion and depreciation expense (“D&D”) of \$8.3 million (\$15.35 per boe) and \$17.8 million (\$15.26 per boe) for the quarter and six months ended June 30, 2026, respectively compared to \$12.0 million (\$18.19 per boe) and \$23.8 million (\$17.87 per BOE) in the same periods of 2025. D&D expense is calculated using the unit-of-production method based on proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production

D&D expense decreased in both Q2 and for the first six months of 2026 compared to the same periods in 2025 largely due to both lower production volume and a lower rate.

Depletion in 2026 is impacted by a \$62.2 million impairment charge recognized in Q4 2025 which resulted in a lower rate. Any future reversals of impairment would result in a higher charge.

The D&D expense recognized was comprised primarily of depletion expense with minor amounts related to depreciation of office assets and field vehicles.

D&D per boe will differ from period to period depending on the amount and type of capital spending, the number of reserves added, and production volume.

EXPLORATION EXPENSE

	Three months ended June 30		Six months ended June 30	
<i>(thousands, except per unit amounts)</i>	2026	2025	2026	2025
Exploration expense	\$162	\$5,776	\$5,032	\$7,028
Per BOE	\$0.30	\$8.76	\$4.31	\$5.28

North 40 recognized exploration expense of \$0.2 million in Q2 2026 (\$0.30 per boe) and \$5.0 million (\$4.31 per boe) in the first half of 2026. The expense in Q2 2026 is due to undeveloped land expiries. Exploration expense in the first half of 2026 relates to costs for an exploratory test well that encountered a drill pipe failure after reaching total depth and was abandoned (\$4.4 million) and to undeveloped land expiries.

North 40 recognized exploration expense of \$5.8 million (\$8.76 per boe) in Q2 2025 and \$7.0 million (\$5.28 per boe) in the first half of 2025. Undeveloped land expiries, most notably in Matziwin South and Wayne, led to the Q2 expense. The first half expense of \$7.0 million is related to undeveloped land expiries and costs related to drilling two test wells in prior years.

LOSS ON ASSETS HELD-FOR-SALE

<i>(thousands, except per unit amounts)</i>	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Loss on assets held-for-sale	\$ -	\$4,479	\$ -	\$4,479
Per BOE	\$ -	\$6.79	\$ -	\$3.37

North 40 entered into a purchase and sale agreement on June 4, 2025 for the disposition of its non-core Entice assets for \$0.3 million in cash. As at June 30, 2025 the Company determined the closing was highly probable and reclassified the Entice assets to asset held for sale. Reclassification of the assets resulted in recognition of a loss of \$4.5 million based on the consideration expected.

The transaction closed on July 30, 2025.

FINANCE EXPENSE

<i>(thousands)</i>	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Accretion of decommissioning obligations	\$204	\$129	\$424	\$253
Interest	201	126	344	193
Banking fees	150	113	193	114
Interest on lease liabilities	5	5	10	10
Total	\$561	\$373	\$971	\$570
Per BOE	\$1.03	\$0.57	\$0.83	\$0.43

Finance expense for Q2 2026 was \$0.6 million (\$1.03 per boe) and \$1.0 million (\$0.83 per boe) for the first half of 2026 compared to \$0.4 million (\$0.57 per boe) and \$0.6 million (\$0.43 per boe) in the same periods of 2025. The increase was driven primarily by higher interest costs resulting from increased borrowings under the Company's credit facility and higher accretion costs mostly from asset acquisitions in the 2025 and Q1 2026.

Finance expense relates to accretion on decommissioning obligations, banking fees, interest on bank borrowings and interest on lease liabilities. Banking fees include standby fees and fees associated with the annual bank facility review.

Accretion of decommissioning obligations and interest on lease liabilities are non-cash charges.

INCOME TAXES

<i>(thousands)</i>	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Current income tax expense	\$164	\$ -	\$721	\$200
Deferred income tax expense (recovery)	1,910	(1,130)	849	163
Income taxes	\$2,074	\$(1,130)	\$1,570	\$363
Per boe	\$3.82	\$(1.71)	\$1.35	\$0.27

North 40 recognized current income tax expense of \$0.2 million and \$0.7 million in Q2 2026 and for the first half of the year compared to nil and \$0.2 million in the comparable periods of 2025 respectively.

Deferred income taxes arise from differences between the accounting and tax basis of assets and liabilities. The estimate of deferred taxes is based on the current tax status of the Company, enacted legislation, and management's best estimates of future events.

For the three and six months ended June 30, 2026, a deferred income tax expense of \$1.9 million and \$0.8 million, respectively, was recognized compared to a deferred income tax recovery of \$1.1 million and \$0.2 million for the comparable periods in 2025.

The following tax pool balances are estimated at June 30, 2026:

<i>(thousands)</i>	Maximum Annual Deduction	June 30 2026	June 30 2025
Canadian oil and gas property expense (COGPE)	10%	\$4,442	\$3,786
Canadian development expense (CDE)	30%	69,996	71,249
Undepreciated capital cost (UCC)	25%	46,225	49,224
		\$120,661	\$124,259

NET INCOME (LOSS) AND COMPREHENSIVE INCOME (LOSS)

<i>(thousands)</i>	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Net income (loss) and comprehensive income (loss)	\$7,086	\$(8,210)	\$5,139	\$(2,455)
Per share - basic	\$0.09	\$(0.11)	\$0.06	\$(0.03)
Per share - diluted	\$0.08	\$(0.11)	\$0.06	\$(0.03)

The increase in net income for the three months ended June 30, 2026, as compared to the same period in 2025 is primarily due to an increase in petroleum and natural gas revenue and other income and decreases in depletion and depreciation, exploration expense, and loss on assets held for sale partially offset by increases in royalties, operating expenses and deferred income tax.

The increase in net income for the six months ended June 30, 2026, as compared to the same period in 2025 is primarily due to an increase in other income and decreases in depletion and depreciation, exploration expense, and loss on sale of assets partially offset by increases in operating expenses and current and deferred income taxes.

CAPITAL EXPENDITURES

Capital expenditures by type and by property for the three and six months ended June 30, 2026, and 2025 were as follows:

<i>(thousands)</i>	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Acquisition	\$ -	\$ -	\$3,615	\$12,392
Land and lease rentals ⁽¹⁾	695	351	817	491
Seismic and geological	-	980	32	980
Drilling and completion	4,441	9,050	18,710	24,375
Equipping and tie-ins	2,364	3,293	6,641	10,070
Facilities	687	2,777	1,475	3,019
Office and other	9	102	19	203
Total capital expenditures	\$8,196	\$16,553	\$31,309	\$51,530

(1) Net of land fund reimbursements.

<i>(thousands)</i>	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Sheerness	\$5,479	\$12,462	\$23,137	\$47,272
Wayne	394	3,461	5,508	3,206
Drumheller	100	269	424	379
Matziwin South	2,060	-	2,060	-
Other	163	361	180	673
Total capital expenditures	\$8,196	\$16,553	\$31,309	\$51,530

Wells drilled by property were as follows:

	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Sheerness	1	4	4	10
Wayne	-	1	1	1
Matziwin South	1	-	1	-
Total	2	5	6	11

Second quarter 2026 capital expenditures of \$8.2 million includes the drilling of two wells and completion of natural gas infrastructure work which commenced in Q1 2026. This project will re-route some natural gas production away from third party facilities to North 40 owned infrastructure.

First half 2026 capital expenditures of \$31.3 million includes the drilling of six wells of which three were completed and four were brought on production. The well drilled at Matziwin South was a open hole multi leg well which was not fracked. One of the Sheerness Q1 2026 wells was drilled and abandoned. After reaching total depth, the well encountered a drill pipe failure and had to be abandoned.

The Company also acquired certain oil and gas properties with no current production in Q1 2026 for \$3.6 million. With this acquisition, North 40 acquired the remaining infrastructure required to consolidate the Company's infrastructure in the Sheerness prospect region and in Q2 2026 completed the reroute pipeline project to consolidate and deliver the Company's natural gas production from the region to a 100% owned North 40 gas plant.

Capital expenditures in Q2 2025 were \$16.6 million. Capital activity included the drilling of five wells (one of which was a water disposal well at Michichi (Sheerness)), completion of one well at Wayne, construction of a water disposal facility at Michichi, (Sheerness), commenced construction of an oil battery at Aerial (Sheerness), acquisition of a 75% working interest in the Seiu Lake natural gas plant in the Drumheller area and several well workovers.

First half 2025 capital expenditures were \$51.5 million and predominantly expended in the Sheerness area. The Company drilled 11 wells. Other capital activities included construction of a water disposal facility at Michichi (Sheerness), commenced construction of an oil battery at Aerial (Sheerness), completion of a pipeline connecting Michichi natural gas production to a natural gas plant (50% working interest), acquisition of a 75% working interest in the Seiu Lake natural gas plant in the Drumheller area, several well workovers, and an acquisition of properties described below.

The Company acquired certain crude oil and natural gas properties with minimal current production for \$12.4 million of cash consideration in the first quarter of 2025. The property consists of approximately 8,300 hectares which has been developed by vertical wells identifying multi-zone potential in Aerial. The property includes a number of inactive and/or suspended wells and facilities. A reactivation and recompletion program will be undertaken later in 2025. To fund this acquisition, the Company sold a royalty interest and an infrastructure volumetric payment on future production. Proceeds from the sale was \$12 million and is not included in the capital expenditure values disclosed above.

LAND HOLDINGS

North 40's net land holdings per area at June 30, 2026 and 2025 were as follows:

<i>(acres)</i>	June 30, 2026	June 30, 2025
Sheerness	189,212	139,515
Drumheller	35,229	54,092
Wayne	8,315	8,937
Tide Lake	21,838	26,427
Matziwin	28,527	13,294
Other	23,096	23,738
Total	306,217	266,003

The land holdings consist of 86% crown and 14% freehold leases at June 30, 2026. Working interest in North 40's land holdings is 94 percent.

DECOMMISSIONING OBLIGATIONS

Decommissioning obligations are based on estimated costs and timing to abandon and reclaim ownership interests in oil and natural gas assets. North 40 has recognized a provision for decommissioning obligations of \$32.5 million at June 30, 2026 (\$30.5 million at December 31, 2025). The increase in the decommissioning obligations is largely due to obligations associated with the properties acquired in Q1 2026 and wells drilled in 2026.

Estimated abandonment and reclamation costs are based on the directives issued by the Alberta Energy Regulator and management's experience. The decommissioning obligation is measured using the estimated present value of costs to abandon and reclaim all ownership interests. Estimated timing of cash flows are aligned with reserve life and regulatory expectations. A risk-free rate of 3.56% (3.55% at December 31, 2025) and an inflation rate of 2.00% (2.00% at December 31, 2025) were used to calculate the best estimate of the decommissioning obligation.

For 2026, the Company plans to spend its mandatory spend requirement of \$0.4 million under the Alberta Energy Regulator's Liability Management Program.

LIQUIDITY AND CAPITAL RESOURCES

At June 30, 2026, the Company had a working capital deficit of \$10.5 million which includes \$7.6 million of bank debt. Activities to date have been largely funded with cash flow from operations, initial equity proceeds, sales of royalty interests and volumetric payments, and bank debt.

At June 30, 2026, the Company had a \$45.0 million revolving demand operating facility with a Canadian chartered bank. The facility bears interest based on the prime rate or Canadian Overnight Repo Rate Average ("CORRA") rates plus a margin. Interest rates applicable to draws and standby fees are based on a pricing margin grid and will change as a result of the ratio of net debt to cash flow as calculated in accordance with the credit facility agreement. Standby fees on undrawn amounts are currently 0.50%. The Company has a letter of credit outstanding for \$0.1 million at June 30, 2026, that reduces the amount otherwise available to be drawn on the operating facility.

The facility includes a financial covenant that requires the "Adjusted Working Capital" ratio (as defined in the credit agreement, with undrawn capacity under the facility included in the definition of current assets) be not less than 1.0 at each fiscal quarter end. The Company was in compliance with this covenant at June 30, 2026. Advances under the facility are secured by a first floating charge debenture and borrowings under the facility may be made by way of prime loans and CORRA loans. The credit facility is subject to periodic review at the lenders' discretion. The next review date has been set for on or before November 30, 2026.

The Company has entered into a Royalty Acquisition Agreement (the "agreement") with an arm's length party (the "party") whereby the party will fund certain crown land purchases incurred by the Company in exchange for a royalty on future production from those crown lands. The term of the agreement is to October 31, 2026. At June 30, 2026, there is \$1.6 million remaining on the funding limit.

SELECTED QUARTERLY INFORMATION

Three Months Ended	Jun 30	Mar 31	Dec 31	Sept 30	Jun 30	Mar 31	Dec 31	Sept 30
	2026	2026	2025	2025	2025	2025	2024	2024
FINANCIAL								
Petroleum and natural gas revenue	\$36,420	\$29,133	\$26,669	\$27,891	\$29,818	\$38,595	\$30,591	\$25,197
Funds flow from operations ⁽¹⁾	\$17,945	\$11,811	\$9,489	\$11,968	\$13,126	\$20,442	\$14,712	\$11,702
Per share – basic	\$0.23	\$0.15	\$0.12	\$0.15	\$0.17	\$0.27	\$0.19	\$0.15
Per share – diluted	\$0.21	\$0.14	\$0.11	\$0.14	\$0.15	\$0.25	\$0.18	\$0.14
Net income (loss)	\$7,086	\$(1,948)	\$(53,680)	\$1,141	\$(8,210)	\$5,756	\$3,494	\$(1,130)
Per share – basic	\$0.09	\$(0.03)	\$(0.69)	\$0.02	\$(0.11)	\$0.08	\$0.05	\$(0.02)
Per share – diluted	\$0.08	\$(0.03)	\$(0.69)	\$0.01	\$(0.11)	\$0.07	\$0.04	\$(0.02)
Capital expenditures ⁽²⁾	\$8,196	\$23,113	\$19,797	\$15,943	\$16,553	\$34,977	\$27,847	\$22,314
Working capital deficiency at end of period ⁽³⁾	\$10,457	\$20,183	\$13,158	\$17,099	\$12,829	\$9,708	\$8,365	\$10,757
Common shares outstanding end of period	77,844	77,773	77,773	77,612	77,612	76,624	76,624	76,624
OPERATING								
Sales volumes								
Oil and liquids (bbls/day)	3,280	3,519	3,821	4,054	4,135	4,754	3,809	3,169
Natural gas (mcf/day)	16,131	20,489	19,079	19,485	18,662	16,231	12,498	10,150
Total (boe/day) ⁽⁴⁾	5,969	6,934	7,001	7,301	7,245	7,459	5,892	4,860
% Oil and liquids	55	51	55	56	57	64	65	65
Commodity prices realized (before pipeline tariffs)								
Oil and liquids (\$/bbl)	116.99	83.65	67.19	75.34	74.94	85.83	85.33	87.55
Natural gas (\$/mcf)	1.84	2.23	2.58	0.71	1.91	2.47	1.73	0.77
Total (\$/boe)	69.28	49.05	43.70	43.73	47.69	60.07	58.84	58.69
Operating netback ⁽⁵⁾ (\$/boe)	34.42	21.92	19.66	20.84	23.07	32.63	30.12	27.59
Funds flow from operations netback (\$/boe) ⁽¹⁾	33.04	18.93	14.73	17.82	19.91	29.87	27.14	26.17
Net wells drilled	2.0	4.0	-	3.0	5.0	6.0	4.0	7.0
Net acres of land at end of period	306,217	288,062	288,609	262,380	266,003	285,113	265,397	267,272

⁽¹⁾ Funds flow from operations and funds flow from operations netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽²⁾ Capital expenditures does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽³⁾ Working capital surplus (deficiency) does not have a standardized measure prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

⁽⁴⁾ Boe conversion is 6:1.

⁽⁵⁾ Operating netback does not have a standardized meaning prescribed by IFRS. See Non-IFRS Measurements section of the MD&A.

NORTH 40

RESOURCES LTD.

Quarterly Condensed Interim Financial Statements
June 30, 2026

North 40 Resources Ltd.

Interim Statements of Financial Position

(unaudited)

June 30

December 31

As at

2026

2025

(\$ thousands)

ASSETS

Current Assets

Cash	22	-
Accounts receivable	12,970	11,086
Prepays and deposits	1,187	957
Total Current Assets	14,179	12,043

Deposit on asset acquisition bid (Note 5)	-	300
Exploration and evaluation assets (Notes 4, 5, and 6)	3,423	6,606
Property, plant and equipment (Notes 5, 6, and 8)	159,727	150,470

Total Assets	177,329	169,419
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LIABILITIES AND SHAREHOLDERS' EQUITY

Current Liabilities

Accounts payable and accrued liabilities	15,801	14,190
Current income taxes	775	237
Decommissioning obligations (Note 11)	435	435
Bank debt (Note 10)	7,625	10,339
Total Current Liabilities	24,636	25,201

Lease liabilities	144	192
Decommissioning obligations (Note 11)	32,069	30,042
Deferred income taxes	2,157	1,307

Total Liabilities	59,006	56,742
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Shareholders' Equity

Share capital (Note 12)	77,215	77,169
Contributed surplus	6,279	5,818
Retained earnings	34,829	29,690
Total Shareholders' Equity	118,323	112,677

Total Liabilities and Shareholders' Equity	177,329	169,419
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The accompanying notes are an integral part of these Financial Statements.

North 40 Resources Ltd.

Interim Statements of Net Income (Loss) and Comprehensive Income (Loss)

(unaudited)

Three months ended June 30

Six months ended June 30

2026

2025

2026

2025

(\$ thousands except per share amounts)

Revenue

Petroleum and natural gas revenue (Note 13)	36,420	29,818	65,553	68,413
Less: Royalties	7,896	6,299	13,737	13,730
	28,524	23,519	51,816	54,683
Other income (Note 14)	1,160	-	1,160	-
Interest income	14	1	14	31
	29,698	23,520	52,990	54,714

Expenses

Operating	8,681	6,921	17,254	14,673
Transportation	1,144	1,383	2,183	2,880
General and administrative	1,407	1,846	2,528	3,077
Share-based compensation (Note 12)	244	91	506	314
Depletion and depreciation (Note 8)	8,339	11,991	17,807	23,785
Exploration expense (Note 4)	162	5,776	5,032	7,028
Loss on assets held-for-sale (Note 7)	-	4,479	-	4,479
Finance expense	561	373	971	570
Total expenses	20,538	32,860	46,281	56,806

Income (loss) before taxes	9,160	(9,340)	6,709	(2,092)
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Current income tax expense	164	-	721	200
Deferred income tax (recovery) expense	1,910	(1,130)	849	163
Income taxes	2,074	(1,130)	1,570	363

Net Income (Loss) and Comprehensive Income (Loss)	7,086	(8,210)	5,139	(2,455)
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Net Income (loss) per share (Note 15)

Basic	\$0.09	\$(0.11)	\$0.06	\$(0.03)
Diluted	\$0.08	\$(0.11)	\$0.06	\$(0.03)

The accompanying notes are an integral part of these Financial Statements.

North 40 Resources Ltd.

Statements of Changes in Equity

(unaudited)

	Share Capital	Contributed Surplus	Retained Earnings	Total Equity
(\$ thousands)				
Balance as at December 31, 2024	76,245	5,806	84,684	166,735
Net loss	-	-	(2,455)	(2,455)
Transferred on conversion of Class B's and C's	780	(780)	-	-
Share-based compensation (Note 12)	-	354	-	354
Balance as at June 30, 2025	77,025	5,380	82,229	164,634
Balance as at December 31, 2025	77,169	5,818	29,690	112,677
Net income	-	-	5,139	5,139
Transferred on conversion of Class B's and C's	46	-	-	46
Share-based compensation (Note 12)	-	461	-	461
Balance as at June 30, 2026	77,215	6,279	34,829	118,323

The accompanying notes are an integral part of these Financial Statements.

North 40 Resources Ltd.

Interim Statements of Cash Flow

(unaudited)

	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
(\$ thousands)				
Cash provided by (used in):				
Operating activities				
Net income for the period	7,086	(8,210)	5,139	(2,455)
Adjusted for:				
Depletion and depreciation (Note 8)	8,339	11,991	17,807	23,785
Exploration expense (Note 4)	162	5,776	5,032	7,028
Loss on assets held-for-sale (Note 7)	-	4,479	-	4,479
Accretion expense (Note 11)	204	129	424	253
Share-based compensation (Note 12)	244	91	506	314
Deferred income tax expense (recovery)	1,910	(1,130)	849	163
	17,945	13,126	29,757	33,567
Net change in non-cash working capital (Note 16)	(1,551)	341	(3,567)	517
	16,394	13,467	26,190	34,084
Financing activities				
Increase (decrease) in bank debt (Note 10)	(3,850)	628	(2,714)	1,779
Repayment of lease liabilities	(21)	6	(47)	(1)
	(3,871)	634	(2,761)	1,778
Investing activities				
Deposit paid on acquisition (Note 5)	-	-	300	1,200
Exploration and evaluation expenditures (Note 4)	(2,168)	(3,400)	(7,289)	(4,211)
Property, plant and equipment expenditures (Note 8)	(6,028)	(13,153)	(20,405)	(34,927)
Acquisition (Note 5)	-	-	(3,615)	(12,392)
Proceeds from dispositions (Notes 4,6, and 8)	-	-	4,000	12,000
Net change in non-cash working capital (Note 16)	(4,305)	2,452	3,602	(3,242)
	(12,501)	(14,101)	(23,407)	(41,572)
Change in cash	22	-	22	(5,710)
Cash, beginning of period	-	-	-	5,710
Cash, end of period	22	-	22	-
Cash income tax paid	-	-	236	-
Interest paid	201	-	143	-

The accompanying notes are an integral part of these Financial Statements.

North 40 Resources Ltd.

Notes to the Financial Statements

As at June 30, 2026 and December 31, 2025, and for the three and six months ended June 30, 2026 and 2025 (*all tabular amounts in thousands of Canadian \$, except per share amounts or as otherwise indicated*).

1. CORPORATE INFORMATION

North 40 Resources Ltd. (the "Company" or "North 40"), is a privately held oil and gas exploration and development company incorporated in the province of Alberta, Canada on October 16, 2007. The address of the principal place of business is 400, 215 – 9th Avenue SW, Calgary, Alberta, Canada T2P 1K3.

The Company explores, acquires, develops, and produces oil and natural gas reserves in the Western Canadian Sedimentary Basin.

2. BASIS OF PRESENTATION

(a) Statement of Compliance

These condensed interim financial statements have been prepared by management in accordance with International Accounting Standard ("IAS") 34 "Interim Financial Reporting" using accounting policies consistent with International Financial Reporting Standards ("IFRS Accounting Standards") as issued by the International Accounting Standards Board ("IASB"). They are condensed as they do not include all of the information required for full annual consolidated financial statements, and they should be read in conjunction with the audited annual consolidated financial statements as at and for the year ended December 31, 2025.

These financial statements have been prepared using the accounting policies and methods as described in Note 3 below.

These financial statements were approved and authorized for issuance by the Board of Directors on September 14, 2026.

3. MATERIAL ACCOUNTING POLICIES

All accounting policies followed in preparation of these financial statements are consistent with those of the previous financial year. The Company's material accounting policies are disclosed in Note 3 of the financial statements for the year ended December 31, 2025, except as disclosed below.

On January 1, 2026, the Company adopted the amendments to IFRS 9 and IFRS 7, relating to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. The amendments were effective on January 1, 2026. The impact from this amendment is immaterial to the financial statements.

4. EXPLORATION AND EVALUATION ASSETS

(\$)	June 30 2026	December 31 2025
Balance, beginning of period	6,606	15,927
Acquisitions (Note 5)	-	26,349
Additions	7,289	7,330
Dispositions (Note 6)	-	(23,004)
Exploration expense	(5,032)	(12,143)
Transferred to property and equipment (Note 8)	(5,440)	(7,853)
Balance, end of period	3,423	6,606

Exploration and evaluation ("E&E") assets consist of the Company's undeveloped land, geological and geophysical assets and exploration drilling projects in which technical feasibility or commercial viability has yet to be determined.

Exploration expense in 2026 relates to costs for an exploratory test well that encountered a drill pipe failure after reaching total depth and was abandoned (\$4.4 million) and to undeveloped land expiries.

Exploration expense in 2025 relates to undeveloped land expiries and costs related to drilling two test evaluation wells in prior years.

5. ACQUISITIONS

2026

On January 13, 2026, the Company completed the acquisition of certain crude oil and natural gas properties in Sheerness (Aerial), primarily pipeline and related infrastructure, with no current production for cash consideration of \$3.6 million. The effective date of the acquisition was January 13, 2026. The acquisition has been accounted for as an asset acquisition as the acquired assets did not meet the definition of a business.

The following purchase price allocation was based on the asset acquired and the liabilities assumed:

(\$)	As at January 13, 2026
Net assets (liabilities) acquired	
Property, plant & equipment	5,236
Decommissioning obligations	(1,621)
Net assets acquired	3,615
Consideration	
Cash	3,210
Accrued payable	405
Total consideration	3,615

A deposit of \$0.3 million was paid in 2025 in connection with this acquisition.

2025

On November 20, 2025, the Company completed the acquisition of certain crude oil and natural gas properties in Sheerness (Aerial) and related infrastructure for cash consideration of \$15.4 million. The effective date of the acquisition was October 1, 2025. The acquisition has been accounted for as a business combination under IFRS 3. Petroleum and natural gas revenues of \$0.4 million and net operating income of \$0.3 million were included in the statement of net income (loss) and comprehensive income (loss) from the closing date of November 20, 2025, to December 31, 2025. If the acquisition had occurred on January 1, 2025, the estimated incremental petroleum and natural gas revenues and net operating income for the year ended December 31, 2025, would have been \$5.3 million and \$3.2 million, respectively.

The following purchase price allocation was based on the asset acquired and the liabilities assumed:

(\$)	As at November 20, 2025
Net assets (liabilities) acquired	
Exploration and evaluation assets	11,999
Property, plant & equipment	7,880
Decommissioning obligations	(4,449)
Net assets acquired	15,430
Consideration	
Cash	15,430
Total consideration	15,430

The acquisition date fair value attributed to property, plant and equipment was derived from the estimate of proved and probable oil and gas reserves and the related cash flows utilizing discount rates between 10% and 20%. The fair value of the decommissioning obligations was initially estimated using a discount rate of 9%. The exploration and evaluation assets fair value was determined based on future net cash flows to be derived from potential drilling locations from undeveloped lands.

On January 13, 2025, the Company completed the acquisition of certain crude oil and natural gas properties in Sheerness (Aerial), primarily inactive wells and related infrastructure, with minimal current production for cash consideration of \$12.4 million. The effective date of the acquisition was January 13, 2025. The acquisition has been accounted for as an asset acquisition as the acquired assets did not meet the definition of a business.

The following purchase price allocation was based on the asset acquired and the liabilities assumed:

(\$)	As at January 13, 2025
Net assets (liabilities) acquired	
Exploration and evaluation assets	14,350
Property, plant & equipment	3,839
Decommissioning obligations	(5,797)
Net assets acquired	12,392
Consideration	
Cash	12,392
Total consideration	12,392

A deposit of \$1.2 million was paid in 2024 in connection with this acquisition.

6. DISPOSITIONS

2026

In Q1 2026, the Company sold a royalty interest and infrastructure volume payment in production from certain lands and pipeline utilization included in the acquisition described in Note 5 (January 13, 2026). Proceeds from the sale were \$4.0 million and were allocated to property, plant and equipment. There was no gain or loss recognized on the disposition.

Persons related to a director purchased a portion of these interests for proceeds totaling \$1.5 million. An arm's length third party purchased the remainder of these interests.

2025

In Q4 2025, the Company sold a royalty interest and infrastructure volume payment on future production from certain lands in Sheerness (Aerial) included in the acquisition described in Note 5 (November 20, 2025). Proceeds from the sale were \$15.0 million and were allocated to E&E assets (\$11.7 million) and to property plant and equipment (\$3.3 million). There was no gain or loss recognized on the disposition.

Persons related to a director purchased a portion of these interests for proceeds totalling \$5.6 million. An arm's length third party purchased the remainder of these interests.

North 40 entered into a purchase and sale agreement on June 4, 2025, for the disposition of its non-core Entice assets for \$0.3 million in cash (\$0.2 million after final adjustments). In Q2 2025 the Company determined the closing was highly probable and reclassified the Entice assets to asset held for sale. Reclassification of the assets resulted in recognition of an impairment on disposition of \$4.5 million based on the sales price. The transaction closed on July 30, 2025.

In Q1 2025, the Company sold a royalty interest and infrastructure volume payment on future production from certain lands in Sheerness (Aerial) included in the acquisition described in Note 5 (January 13, 2025). Proceeds from the sale were \$12.0 million and were allocated to E&E assets (\$11.3 million) and to property plant and equipment (\$0.7 million). There was no gain or loss recognized on the disposition.

Persons related to two directors purchased a portion of these interests for proceeds totalling \$6.0 million. An arm's length third party purchased the remainder of these interests.

7. ASSETS HELD-FOR-SALE

In Q2 2025, the Company signed a definitive agreement to sell its Entice assets. The closing of the sale was subject to terms that are usual and customary, and it was highly probable that it would close. A loss of \$4.5 million has been recognized. The assets held-for-sale value is \$0.3 million.

8. PROPERTY, PLANT AND EQUIPMENT

(\$)	June 30 2026	December 31 2025
Property and equipment, at cost	452,322	425,259
Accumulated depletion and depreciation	(292,595)	(274,789)
Net book value, end of period	159,727	150,470
Reconciliations of movements during the period:		
Cost, beginning of period	425,259	346,933
Accumulated depletion and depreciation, beginning of period	(274,789)	(161,002)
Net book value, beginning of period	150,470	185,931
Additions	20,405	52,349
Acquisitions (Note 5)	3,615	11,719
Dispositions (Note 6)	(4,000)	(4,181)
Transferred from exploration and evaluation assets	5,440	7,853
Changes in decommissioning obligations	1,604	10,557
Depletion and depreciation	(17,807)	(47,120)
Impairment (Note 9)	-	(62,159)
Impairment on disposition (Note 6)	-	(4,479)
Net book value, end of period	159,727	150,470

Included in the calculation of depletion was an estimate for future development costs of \$118.0 million at June 30, 2026 (\$124.7 million at December 31, 2025). An estimated future salvage value of \$13.4 million was excluded from the calculation of depletion at June 30, 2026 (\$12.8 million at December 31, 2025).

Included in the June 30, 2026, property, plant and equipment balance is the right-of-use asset of \$0.1 million (\$0.2 million at December 31, 2025).

9. IMPAIRMENT

(\$)	March 31 2026	December 31 2025
Impairment of property, plant and equipment	-	62,159

North 40 has one CGU as of June 30, 2026, and at December 31, 2025. At December 31, 2025, indicators of impairment were identified due to a lower commodity price environment and negative technical revisions for crude oil. As a result, an impairment test was performed. The recoverable value was estimated at fair value less costs to sell based on before tax discounted cash flows from proved and probable oil and gas reserves, based on the underlying composition of reserve categories.

At December 31, 2025, it was determined that the carrying value exceeded the estimated recoverable amount and a \$62.2 million impairment was recognized. The before tax discount rate applied in the calculation ranged between 10% and 20% depending on the reserve category.

The results of the impairment tests are sensitive to changes in any of the key significant assumptions, including forecasted oil and commodity prices, forecasted production volumes, forecasted operating costs, royalty costs and future development costs, which impact the estimate of cash flows from proved and probable oil and gas reserves, in addition to the discount rate, of which changes could increase or decrease the estimated recoverable amount of the CGU and result in additional impairment charges or in the recovery of previously recorded impairment charges. All estimates are subject to uncertainty.

The following table outlines forecasted oil and natural gas prices and exchange rates used in the Company's impairment test as at December 31, 2025. The forecasted oil and natural gas prices are based on those used by the independent third-party external reserve evaluator at December 31, 2025, and are a key assumption in assessing the recoverable amount.

Year	WTI Cushing Oklahoma (\$US)	Oil			Gas	
		Edmonton Light (\$C)	N40 Oil Price (\$C)	Henry Hub (\$US)	AECO Spot (\$C)	N40 Gas Price (\$C)
		(\$/bbl)			(\$/mmbtu)	
2026	59.92	77.54	69.64	3.74	3.00	2.80
2027	65.10	83.60	75.28	3.78	3.30	3.13
2028	70.28	90.17	81.27	3.85	3.49	3.32
2029	71.93	92.32	83.30	3.93	3.58	3.40
2030	73.37	94.17	84.97	4.01	3.65	3.46
2031	74.84	96.06	86.92	4.09	3.72	3.51
2032	76.34	97.98	88.63	4.17	3.80	3.59
2033	77.87	99.93	90.44	4.26	3.88	3.66
2034	79.42	101.93	92.25	4.34	3.95	3.75

2.0% per annum increase thereafter

A one percent change in the discount rate or a five percent change in the forward price over the life of the reserves would result in changes in impairment of \$3.8 million and \$20.0 million respectively.

At June 30, 2026, there were no indicators of impairment or reversal of impairment identified and an impairment test was not performed.

10. CREDIT FACILITY

At June 30, 2026, the Company had a \$45.0 million revolving demand operating facility with a Canadian chartered bank. The facility bears interest based on the prime rate or Canadian Overnight Repo Rate Average ("CORRA") rates plus a margin. Interest rates applicable to draws and standby fees are based on a pricing margin grid and will change as a result of the ratio of net debt to cash flow as calculated in accordance with the credit facility agreement. Standby fees on undrawn amounts are currently 0.50%. The Company has a letter of credit outstanding for \$0.1 million at June 30, 2026, that reduces the amount otherwise available to be drawn on the operating facility.

The facility includes a financial covenant that requires the "Adjusted Working Capital" ratio (as defined in the credit agreement, with undrawn capacity under the facility included in the definition of current assets) be not less than 1.0 at each fiscal quarter end. The Company was in compliance with this covenant at June 30, 2026. Advances under the facility are secured by a first floating charge debenture and borrowings under the facility may be made by way of prime loans and CORRA loans. The credit facility is subject to periodic review at the lenders' discretion. The next review date has been set for November 30, 2026.

At June 30, 2026, there was \$7.6 million drawn on the facility (\$10.3 million at December 31, 2025).

11. DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from its responsibility to abandon and reclaim its net ownership interests in oil and natural gas assets including well sites, gathering systems and processing facilities. The total decommissioning obligation is estimated based on the Company's net ownership interest in wells and facilities, the estimated costs to abandon and reclaim the wells, gathering systems and facilities and the estimated timing of future costs. The Company estimates the total uninflated adjusted and undiscounted amount of cash flows required to settle its decommissioning obligations is approximately \$43.4 million (\$40.6 million at December 31, 2025).

A reconciliation of the decommissioning obligations is provided below.

(\$)	June 30 2026	December 31 2025
Balance, beginning of year	30,477	9,115
Liabilities incurred	819	1,791
Liabilities acquired with acquisitions	1,620	10,247
Change in estimates	(836)	2,184
Change in discount rate on acquisition	-	6,753
Obligations disposed	-	(199)
Accretion expense	424	586
Balance, end of period	32,504	30,477
Expected to be incurred within one year	435	435
Expected to be incurred beyond one year	32,069	30,042
Key assumptions		
Risk free rate	3.56%	3.55%
Inflation rate	2.00%	2.00%

12. SHARE CAPITAL

Authorized

Unlimited number of common voting shares ("common shares") without nominal or par value

Unlimited number of Class B common non-voting shares ("Class B") without nominal or par value

Unlimited number of Class C common non-voting shares ("Class C") without nominal or par value

Issued and Outstanding		June 30 2026		December 31 2025
	Number	Amount	Number	Amount
Common Shares				
Balance, beginning of period	77,773	\$77,042	76,624	\$76,093
Issued on conversion of Class B's and C's	71	48	1,149	949
Balance, end of period	77,844	\$77,090	77,773	\$77,042
Class B Common Non-Voting Shares				
Balance, beginning of period	3,770	\$38	4,870	\$49
Converted to common shares	(100)	(1)	(1,100)	(11)
Balance, end of period	3,670	\$37	3,770	\$38
Class C Common Non-Voting Shares				
Balance, beginning of period	8,950	\$89	10,380	\$103
Converted to common shares	-	-	(715)	(7)
Forfeited	(130)	(1)	(715)	(7)
Balance, end of period	8,820	\$88	8,950	\$89
Total		\$77,215		\$77,169

Common Shares

Common shares are subject to the provisions and terms contained in Schedule A of the Company's Articles of Incorporation and to the provisions and terms of the respective share subscription agreements among the Company and its shareholders.

Class B Shares and Options on Class B Shares

Class B shares and options on Class B shares have been reserved for issue to directors, officers, employees, and consultants of the Company. The aggregate number of Class B shares and options issued may not exceed 10% of the issued and outstanding common shares of the Company.

Class B shares are convertible to common shares of the Company until expiry in September 2029 at an exercise price of \$1.00 per share. One third of the Class B shares purchased and options granted will vest equally on each of the second, third and fourth

anniversary of the issue date. At June 30, 2026, 3,670,000 Class B shares and 1,255,333 options on Class B shares have vested (3,870,000 and 932,250 respectively at June 30, 2025).

The number and weighted average exercise price of the options on Class B shares are as follows:

	Number of Options	Weighted Average Exercise Price
Balance, January 1, 2025	2,297,000	\$0.83
Granted	245,000	1.40
Exercised	(370,858)	(0.89)
Forfeited	(134,142)	(1.07)
Balance, December 31, 2025	2,037,000	\$0.78
Granted	815,000	1.80
Exercised	(16,700)	(1.67)
Forfeited	(3,300)	(2.00)
Balance, June 30, 2026	2,832,000	\$1.08

The fair market value of each Class B option granted in 2026 was estimated on the date of issue using the Black-Scholes pricing model and the following weighted average assumptions in the calculations:

Risk-free interest rate (%)	2.61
Expected life (years)	2.0 - 3.0
Estimated volatility of underlying common shares (%)	60
Share Price (\$)	2.80
Estimated forfeiture rate (%)	nil

The Company recognized share-based compensation expense of \$126,036 and \$270,033 related to the Class B options for the for the three and six months ended June 30, 2026 (\$66,393 and \$146,251 for the three and six months ended June 30, 2025) and capitalized nil (\$7,185 and \$16,231 for the three and six months ended June 30, 2025).

Class C Shares and Options on Class C Shares

Class C shares and options on Class C shares have been reserved for issue to directors, officers, employees, and consultants of the Company. The aggregate number of Class C shares and options issued may not exceed 20% of the issued and outstanding common shares of the Company.

Class C shares are convertible to common shares of the Company if a liquidity event occurs before September 2026 at certain minimum price thresholds per share. A liquidity event includes the sale of all or substantially all of the common shares of the Company or assets for consideration that includes cash and/or securities, the liquidation of the Company, or any listing of the Company on a recognized exchange. The Class C shares were issued with various minimum price vesting and exercise price thresholds.

A summary of the number of Class C shares (assuming exercise of options on Class C shares) that vest and are convertible upon achieving price thresholds and at various exercise prices is as follows:

Number of Class C Shares Convertible	Liquidity Event Price Per Fully Diluted Share	Conversion Price Per Share
2,309,833	\$1.50	\$1.00
2,309,833	\$2.00	\$1.15
2,309,833	\$2.25	\$1.30
2,309,833	\$2.50	\$1.45
2,309,833	\$2.75	\$1.60
2,309,833	\$3.00	\$1.75

The number and weighted average exercise price of the options on Class C shares are as follows:

	Number of Options	Weighted Average Exercise Price
Balance, January 1, 2025	3,899,000	\$0.82
Granted	485,000	1.40
Exercised	(343,332)	(0.85)
Forfeited	(401,668)	(0.93)
Balance, December 31, 2025	3,639,000	\$0.77
Granted	1,420,000	1.80
Forfeited	(20,000)	(1.73)
Balance, June 30, 2026	5,039,000	\$1.07

The fair market value of each Class C option granted in 2026 was estimated on the date of issue using the Black-Scholes pricing model and the following assumptions in the calculations:

Risk-free interest rate (%)	2.61
Expected life (years)	2.5
Estimated volatility of underlying common shares (%)	60
Share Price (\$)	2.80
Estimated forfeiture rate (%)	nil

In addition, the Company assumed the probability of a liquidity event within the term to be 25% and the probability of achieving the price thresholds disclosed in the table above to be 95%, 90%, 90%, 85%, 85% and 80%, respectively.

The Company recognized share-based compensation expense of \$117,784 and \$236,314 related to the Class C shares and options for the three and six months ended June 30, 2026 (\$24,570 and \$168,194 for the three and six months ended June 30, 2025) and capitalized nil (\$4,952 and \$23,016 for the three and six months ended June 30, 2025).

13. REVENUES

The Company produces crude oil, natural gas, and natural gas liquids from its assets in Alberta. The Company sells its production pursuant to variable-price physical delivery contracts. The transaction price for variable-price contracts is based on a benchmark commodity price, adjusted for quality, location and/or other factors whereby each component of the pricing component is fixed or variable, depending on the contract terms. Under the contracts, the Company is required to deliver fixed or variable quantities of crude oil, natural gas and natural gas liquids to the contract counterparty.

Petroleum and natural gas revenue is recognized when control is transferred from North 40 to its customers which is typically when the product enters the terminal or pipeline. Revenue is measured based on the consideration specified in a contract with the customer and the volumes delivered. North 40's revenue was generated in Alberta and sold to customers in the oil and natural gas business subject to normal credit terms and under customary industry sale and payment terms at monthly market prices. Contract terms are one year or less. Crude oil and natural gas revenues are collected on or about the 25th day of the month following production.

	Three months ended June 30		Six months ended June 30	
(\$)	2026	2025	2026	2025
Crude oil revenues	30,878	24,853	53,677	57,954
Natural gas revenues	2,279	2,686	5,780	5,779
Natural gas liquids revenues	3,263	2,279	6,096	4,680
Total	36,420	29,818	65,553	68,413

14. OTHER INCOME

The Company sold a portion of its Emission Performance Credits in Q2 2026 for proceeds of \$1.16 million.

15. NET INCOME (LOSS) PER SHARE

	Three months ended June 30		Six months ended June 30	
	2026	2025	2026	2025
Net Income (loss) per share				
Basic	\$0.09	\$(0.11)	\$0.06	\$(0.03)
Diluted	\$0.08	\$(0.11)	\$0.06	\$(0.03)
Weighted average shares outstanding				
Basic	77,819	76,659	77,796	76,642
Diluted	83,929	85,035	84,303	85,355

16. SUPPLEMENTAL CASH FLOW INFORMATION

Changes in non-cash working capital is comprised of the following:

(\$)	June 30 2026	June 30 2025
Source / (use) of cash:		
Accounts receivable	(1,884)	3,077
Prepaid expenses and deposits	(230)	(552)
Accounts payable and accrued liabilities	1,611	(5,450)
Current income taxes	538	200
Change in non-cash working capital	(35)	(2,725)
Related to:		
Operating activities	(3,567)	517
Investing activities	3,602	(3,242)

17. COMMITMENTS

(\$)	Within 1 year	After 1 year but not more than 5 years	Total
Firm transportation – natural gas	366	795	1,161
Office lease	199	321	520
Total	565	1,116	1,681

18. RELATED PARTIES

In Q1 2026, the Company sold a royalty interest and an infrastructure volumetric payment on current and future production on certain lands in the Sheerness area for proceeds of \$4.0 million. Persons related to one of the Company's directors purchased a portion of these interests for proceeds totalling \$1.5 million. An arm's length third party purchased the remainder of these interests.

In Q4 2025, the Company sold a royalty interest and an infrastructure volumetric payment on current and future production on certain lands in the Sheerness area for proceeds of \$15.0 million. Persons related to one of the Company's directors purchased a portion of these interests for proceeds totalling \$5.6 million. An arm's length third party purchased the remainder of these interests.

In Q1 2025, the Company sold a royalty interest and an infrastructure volumetric payment on current and future production on certain lands in the Sheerness area for proceeds of \$12.0 million. Persons related to two of the Company's directors purchased a portion of these interests for proceeds totalling \$6.0 million. An arm's length third party purchased the remainder of these interests.

19. CAPITAL RISK MANAGEMENT

The Company's objectives when managing capital are to deploy capital to provide an appropriate return on shareholder investment and to maintain financial flexibility to execute on strategic opportunities and meet financial obligations. The Company manages its capital structure and makes adjustments to respond to changes in economic conditions and the risk characteristics of its underlying oil and natural gas assets.

The Company has entered into a Royalty Acquisition Agreement (the "agreement") with an arm's length party (the "party") whereby the party will fund certain crown land purchases incurred by the Company in exchange for a royalty on future production from those crown lands. The term of the agreement is to October 31, 2026. At June 30, 2026, there is \$1.6 million remaining on the funding limit.

The Company considers its capital structure to include shareholder's equity, the bank credit facility and working capital. In order to maintain or adjust the capital structure, the Company may from time to time issue new shares, draw on the bank credit facility and/or adjust its capital spending.

20. FINANCIAL RISK MANAGEMENT

Credit risk

The Company may be exposed to certain losses in the event that counterparties fail to meet their obligations in accordance with agreed terms. The Company mitigates this risk by entering into transactions with highly rated major financial institutions and by routinely assessing the financial strength of its customers.

At June 30, 2026, and December 31, 2025, financial assets on the statement of financial position are comprised of cash and trade and other receivables and the maximum credit risk associated with these financial instruments is the total carrying amount of these financial assets.

Accounts receivable for crude oil and natural gas sales are collected on or about the 25th day of the month following production.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they are due. The Company's approach to managing liquidity is to ensure that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions. The Company utilizes authorizations for expenditures on both operated and non-operated projects to manage capital expenditures.

The Company's financial liabilities on the statement of financial position consist of trade and other payables.

The Company expects to satisfy obligations under trade and other payables in less than one year.

The Company has a \$45 million revolving demand operating facility with a Canadian chartered bank. At June 30, 2026, \$7.6 million was drawn on this facility.

Market risk

Market risk is comprised of currency risk, interest rate risk and commodity price risks which consist primarily of fluctuations in petroleum and natural gas prices. The valuation of the financial assets and liabilities on the statement of financial position as at June 30, 2026, and December 31, 2025, has not been significantly impacted by changes in currency rates. Currency rates influence petroleum and natural gas prices; however, this influence on commodity prices and the resulting impact on financial assets and liabilities cannot be accurately quantified.

Interest rate risk

The Company is exposed to interest rate risk to the extent that changes in market interest rates will impact any bank interest earned/indebtedness that has a floating interest rate, potentially affecting future cash flows. As a means to mitigating exposure to interest rate risk, the Company has the ability to enter into interest rate swap agreements. There were no outstanding contracts at June 30, 2026, and December 31, 2025.

Commodity price risk

The Company may be exposed to commodity price risk arising from the effect that fluctuations of future commodity prices may have on the fair value or future cash flows of financial assets and liabilities. There were no outstanding contracts at June 30, 2026, and December 31, 2025.

Corporate Information

OFFICERS

Don Robson
President and Chief Executive Officer

Kim Schoenroth
Vice President Finance and Chief Financial Officer

Gerald Aleman
Vice President, Production

Calvin House
Vice President, Land and Business Development

Preston Kraft
Vice President, Operations

Dermot O'Connor
Vice President, Exploration

Lonny Tetley
Corporate Secretary

DIRECTORS

Clayton Woitas
Executive Chairman

Tyson Birchall

Jeff Lebbert

Margaret McKenzie

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