NORTH 40
RESOURCES LTD.

April 3, 2024

PRESIDENT'S MESSAGE

North 40 Resources Ltd. is pleased to report its operating and financial results for the three months and the year ended December 31, 2023. Fourth quarter and full year highlights include:

- Annual average production rate of 6,363 boe/day (65% oil and liquids).
- Total annual operating revenue of $143.4 mm.
- Realized Q4 2023 average quarterly production of 6,418 boe/day (64% oil and liquids).
- Executed a $85.7 million capital program in 2023 investing in sixteen wells.
- Booked proved plus probable reserves of 14,052 mmboe, a 12% increase over the same period 2022.
- Drilled and brought on production the first three exploration horizontal Basal Quartz oil wells on the Sheerness prospects.
- Ended the year with total land holdings of 285,480 acres.
- Maintained strong LMR rating of 18.3 in March 2024.

North 40 drilled 16 wells in 2023 with twelve wells drilled in the first three quarters and four wells drilled in Q4 2023. The sixteen wells included six horizontal wells at Wayne, three wells at Drumheller (consisting of one Banff horizontal well, a water disposal well and one horizontal Basal Quartz oil well), one horizontal Glauconitic oil well at Matziwin South, one vertical Mannville gas well at Princess, two horizontal exploration multi-leg lower Mannville oil wells at Tide Lake and three exploration horizontal Basal Quartz oil wells at Sheerness.

Sheerness

To date four horizontal wells have been drilled. All wells have produced at commercial rates. These wells have been produced at restricted rates because of limited solution gas take away or gas flaring limitations. Even with these limits, average IP60's of 550 boe/day at 70% oil and liquids was realized. The production is comprised of light oil and liquids rich gas.

Tide Lake

A multi lateral open hole well made a discovery of a high quality reservoir that was oil bearing. Oil rates of 250 bopd with a 75% water cut were encountered. A second step out well came in structurally high but unexpectedly wet. Further drilling will be curtailed as a thorough geological and technical review is underway.

The discovery well will be on production once a suitable water disposal facility is in place.

Seismic Programs

The Sheerness and Connorsville 3D seismic programs were completed by North 40 in Q1 2024 and are now being interpreted.

Shut in Production

In February 2024, North 40 shut-in volumes of non associated gas of about 700 boe/day and has an additional 700 bbl. per day of oil restricted or shut in due to facility limitations.

2024 Operations

The Board of Directors has approved a 2024 capital budget of $82 mm, which includes 18 wells, facilities, pipelines, recompletions and land acquisitions.

The Q1 drilling program was modest with only 3 wells drilled.

After break-up, an oil development program at the Drumheller Banff oil pool will commence and be followed by a development/exploration program at Sheerness.

Current North 40 production is approximately 5,500 boe/day with oil and liquids representing 65% of production.

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

Sincerely,

NORTH 40 RESOURCES LTD.

Don W. Robson
President & CEO

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MANAGEMENT'S DISCUSSION AND ANALYSIS

The following analysis was prepared as at April 3, 2024 and should be read in conjunction with North 40 Resources Ltd.'s ("North 40" or "the Company") audited financial statements for the years ended December 31, 2023 and December 31, 2022, together with the accompanying notes, which have been prepared in accordance with IFRS Accounting Standards ("IFRS" or "GAAP").

Basis of Presentation – *The reporting and the 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.

	Three months ended December 31		*Year ended December 31*	
(millions)	*2023*	*2022*	*2023*	*2022*
Cash provided by operating activities	*$21.8*	*$22.6*	*$69.7*	*$67.5*
Plus (Less): Net change in non-cash working capital	*(4.5)*	*(4.4)*	*2.9*	*(6.0)*
Funds flow from operations	*$17.3*	*$18.2*	*$72.6*	*$61.5*

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.

Capital Expenditures

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

(thousands, except per unit amounts and where indicated)	Three Months Ended December 31 2023	2022	Year Ended December 31 2023	2022
FINANCIAL				
Petroleum and natural gas revenue	$34,594	$34,029	$143,418	$116,333
Funds flow from operations [(1)]	$17,289	$18,206	$72,594	$61,509
Per share – basic	$0.23	$0.24	$0.95	$0.81
Per share – diluted	$0.21	$0.23	$0.90	$0.77
Net income	$ 945	$8,186	$20,134	$30,865
Per share – basic	$0.01	$0.11	$0.26	$0.41
Per share – diluted	$0.01	$0.10	$0.25	$0.39
Capital expenditures [(2)]	$21,512	$17,638	$85,716	$67,625
Working capital surplus (deficiency) [(3)] at end of period	$(6,114)	$7,139	$(6,114)	$7,139
Common shares outstanding at end of period	76,624	76,624	76,624	76,624
OPERATING				
Sales volumes				
Oil and liquids (bbls/day)	4,076	3,391	4,144	2,560
Natural gas (mcf/day)	14,052	10,693	13,317	10,020
Total (boe/day) [(4)]	6,418	5,174	6,363	4,230
% Oil and liquids	64	66	65	61
Commodity prices realized (before pipeline tariffs)				
Oil and liquids ($/bbl)	87.40	96.05	89.54	106.16
Natural gas ($/mcf)	2.54	5.42	2.95	5.75
Total ($/boe)	61.08	74.17	64.48	77.88
Operating netback [(5)] ($/boe)	30.74	42.56	34.41	45.28
Funds from operations netback ($/boe) [(1)]	29.28	38.25	31.25	39.84
Net wells drilled	4.0	3.0	16.0	17.0
Net acres of land at end of period	285,480	224,578	285,480	224,578

(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. Working capital deficiency at December 31, 2023, includes $8.0 million in cash ($19.1 million at December 31, 2022).*
(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 December 31 2023	2022	Year Ended December 31 2023	2022
Oil (bbls per day)	3,665	3,148	3,795	2,337
Liquids (bbls per day)	411	244	349	222
Natural gas (mcf per day)	14,052	10,693	13,317	10,020
BOE per day	6,418	5,174	6,363	4,230

Production in Q4 2023 and for the year ended December 31, 2023, averaged 6,418 boe per day (64% oil and liquids) and 6,363 boe per day (65% oil and liquids) respectively, compared to 5,174 boe per day (66% oil and liquids) and 4,230 boe per day (61% oil and liquids) in the comparable periods of 2022. Production increases are primarily due to the 2023 drilling programs partially offset by expected natural declines of existing production. The Company brought 14 wells on production in 2023 of which three wells were in Q4.

Oil and liquids production increased 20% to 4,076 bbls per day in Q4 2023 compared to 3,392 bbls per day in Q4 2022 and increased 62% to 4,144 bbls per day in 2023 compared to 2,559 bbls per day in 2022. The Wayne wells drilled in 2023 (six wells) were the largest contributors to production increase in both Q4 and 2023. First production from the Sheerness and Tide Lake areas were achieved in Q4 2023.

Natural gas production increased 31% and 33% in Q4 and 2023 respectively compared to the same periods in 2023. The increase is contributed to a Drumheller natural gas well brought on production late in Q1 2023 as well as associated natural gas production from the other wells drilled in 2023.

OPERATING NETBACKS[1]

($ per BOE)	Three Months Ended December 31 2023	Three Months Ended December 31 2022	Year Ended December 31 2023	Year Ended December 31 2022
Revenue *(1)*	$58.59	$71.49	$61.75	$75.36
Royalties	(13.17)	(16.87)	(13.61)	(18.23)
Operating expenses	(12.37)	(10.02)	(11.22)	(9.94)
Transportation expenses	(2.31)	(2.04)	(2.51)	(1.91)
Operating netback *(2)*	$30.74	$42.56	$34.41	$45.28

(1) Includes pipeline tariff amount of $2.49 and $2.73 per boe for the three months and year ended December 31, 2023, and $2.68 and $2.52 per boe in the comparable periods of 2022 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 lower in Q4 2023 and 2023 compared to the same periods in 2022 primarily due to lower oil and natural gas prices and higher operating and transportation expenses partially offset by lower royalties.

COMMODITY PRICES

($ per bbl)	Three Months Ended December 31 2023	Three Months Ended December 31 2022	Year Ended December 31 2023	Year Ended December 31 2022
WTI (US$/bbl)	$78.27	$82.65	$77.62	$94.23
MSW benchmark price *(1)*	$99.60	$110.06	$100.42	$120.07
WCS benchmark price *(2)*	$76.72	$77.42	$79.58	$98.51
Realized crude oil price	$91.21	$98.44	$92.68	$109.52

(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 Q4 2023 was $91.21 per barrel which is 7% lower than the Q4 2022 price (before pipeline tariffs) of $98.44 per barrel. WTI benchmark prices decreased 5% from $82.65 per barrel in Q4 2022 to $78.27 per barrel in Q4 2023 resulting in a decrease in North 40’s realized price.

North 40’s realized crude oil price (before pipeline tariffs) decreased 15% in 2023 to $92.68 per barrel from $109.52 per barrel realized (before pipeline tariffs) in 2022. WTI benchmark prices decreased 18% from $94.23 per barrel in 2022 to $77.62 per barrel in 2023 contributing to most of the decrease in North 40’s realized price which was partially offset by a weaker Canadian dollar. Wider Canadian stream differentials also contributed to the lower realized price in 2023.

WTI benchmark prices declined in 2023 compared to 2022 primarily due to macroeconomic concerns, including recession risk from increasing interest rates aimed at reducing inflationary pressures. Support for oil prices continued with OPEC+ production curtailments and geopolitical conflicts particularly in the Middle East and Russia / Ukraine.

($ per mcf)	Three Months Ended December 31 2023	Three Months Ended December 31 2022	Year Ended December 31 2023	Year Ended December 31 2022
AECO Daily (5A) index	$2.30	$5.12	$2.64	$5.32
Realized natural gas price	$2.54	$5.42	$2.95	$5.75

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 53% to $2.54 per mcf in Q4 2023 from $5.42 per mcf in Q4 2022 and decreased 49% to $2.95 per mcf for 2023 from $5.75 per mcf in 2022.

North American natural gas prices have moved materially lower due to milder weather and an increase in Canadian and US supply causing higher storage levels.

REVENUE

($ thousands)	Three Months Ended December 31 2023	2022	Year Ended December 31 2023	2022
Oil and liquids	$31,695	$29,037	$130,563	$96,528
Natural gas	2,899	4,992	12,855	19,805
Petroleum and natural gas revenue	$34,594	$34,029	$143,418	$116,333
% Oil and liquids	92	85	91	83

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

Revenue in Q4 2023 of $34.6 million was relatively flat compared to Q4 2022 revenue of $34.0 million. Revenue impact from production volume increases in Q4 2023 were almost entirely offset by commodity price declines for oil, natural gas and liquids.

Revenue for the year ended December 31, 2023 increased by 23% from $116.3 million in 2022 to $143.4 million as the revenue impact from increased production volumes exceeded the impact of lower realized prices for all commodities. The increase in crude oil production volume was the largest contributor.

Oil and liquids revenue represented 92% of total revenue in Q4 2023 and increased 9%, from $29.0 million in Q4 2022 to $31.7 million in Q4 2023. Crude oil realizations were 7% lower and oil production volumes were 16% higher in Q4 2023 compared to the same quarter last year. Oil and liquids revenue for 2023 represented 91% of total annual revenue and increased 35% to $130.6 million from $96.5 million in 2022. Oil production volumes were 62% higher and crude oil realizations were 15% lower in 2023 compared to 2022.

Natural gas revenue declined 42% in Q4 2023 from $5.0 million in Q4 2022 to $2.9 million in Q4 2023. The decrease is due to a 53% decline in price realizations partially offset by a 31% increase in production volume in Q4 2023 compared to the same period in 2022. Natural gas revenue for 2023 represented 9% of total revenue and decreased 35% compared to 2022 due to a 49% decrease in price partially offset by a 33% increase in production volume.

Oil pipeline tariffs of $1.1 million and $4.9 million are included in revenue for the fourth quarter and the year ended December 31, 2023 respectively. This compares to $0.9 million and $2.6 million in the same periods of 2022. 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 $1.5 million are also included in revenue for the three months and year ended December 31, 2023, respectively. This compares to $0.3 million and $1.2 million in the same periods of 2022. 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 December 31 2023	2022	Year Ended December 31 2023	2022
Royalties	$7,780	$8,029	$31,610	$28,144
Per BOE	$13.18	$16.87	$13.61	$18.23
% of Revenue before pipeline tariffs	22%	23%	21%	23%

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 on a boe basis decreased to $13.18 and $13.61 per boe in Q4 2023 and 2023 respectively compared to $16.87 and $18.23 per boe in the comparable periods of 2022 commensurate with lower realized prices in 2023. On an absolute basis, royalties were relatively flat at to $7.8 million in Q4 2023 compared to $8.0 million in Q4 2022. Royalties were $31.6 million for 2023 compared to $28.1 million in 2022 with the increase due to higher production volumes partially offset by lower price realizations.

Royalties as a percentage of revenue were 22% and 23% in the fourth quarters of 2023 and 2022 respectively. Royalties as a percentage of revenue decreased to 21% for the year ended December 31, 2023 compared to 23% for the same period in 2022.

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 December 31		Year Ended December 31	
(thousands, except per unit amounts)	2023	2022	2023	2022
Operating expenses	$7,307	$4,771	$26,049	$15,340
Per BOE	$12.37	$10.02	$11.22	$9.94
Transportation expenses	$1,363	$973	$5,828	$2,949
Per BOE	$2.31	$2.04	$2.51	$1.91

Operating expenses averaged $12.37 ($7.3 million) and $11.22 per boe ($26.0 million) for the fourth quarter and year ended December 31, 2023, respectively compared to $10.02 ($4.8 million) and $9.94 per boe ($15.3 million) for the same periods in 2022. Main contributors to the increase were well servicing and maintenance costs, water handling, chemicals and labor services.

Transportation costs, which are clean oil trucking expenses, averaged $2.31 ($1.4 million) and $2.51 ($5.8 million) per boe in the fourth quarter and the year ended December 31, 2023, respectively compared to $2.04 ($1.0 million) and $1.91 ($2.9 million) per boe in the same periods of 2022. The cost is incurred on oil production only and therefore changes in the natural gas production weighting will impact the per boe cost.

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.

GENERAL AND ADMINISTRATIVE

	Three Months Ended December 31		Year Ended December 31	
(thousands, except per unit amounts)	2023	2022	2023	2022
Gross G&A	$2,021	$1,392	$4,366	$4,021
Capitalized G&A	(164)	(136)	(295)	(264)
Net G&A	$1,857	$1,256	$4,071	$3,757
Per BOE	$3.14	$2.64	$1.75	$2.43

Net general and administrative ("G&A") expenses were $1.9 million and $4.1 million for the fourth quarter and the year ended December 31, 2023 respectively compared to $1.3 million and $3.8 million in the comparable periods of 2022.

G&A in Q4 was higher primarily due to the addition of office staff and bonus payments when compared to Q4 2022. G&A for 2023 increased from 2022 due to the addition of office staff in Q4, increase in bonus payments, professional and contract services, higher insurance premiums and computer software costs. In 2022, the Company incurred termination payments related to a leadership change.

On a boe basis, net G&A was $3.14 and $1.75 per boe in Q4 and for the year ended December 31, 2023 respectively compared to $2.64 and $2.43 per boe in same periods of 2022.

Capitalized G&A relates to a portion of the Company's engineering compensation.

SHARE BASED COMPENSATION

	Three Months Ended December 31		Year Ended December 31	
(thousands, except per unit amounts)	2023	2022	2023	2022
Share based compensation	$256	$64	$1,319	$186
Capitalized share-based compensation	(20)	(4)	(136)	(14)
	$236	$60	$1,183	$171
Per BOE	$0.40	$0.14	$0.51	$0.11

Share based compensation expense 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.

In June 2023, the Board of Directors extended the expiry of certain Class B and Class C shares and options to September 2026 from September 2023. The term extension is a modification under IFRS and requires an update to the calculation of share-based compensation expense.

Incremental value of $0.6 million was determined for the vested Class B shares and options. This incremental value is recognized immediately and $0.5 million has been expensed and $0.1 million has been capitalized in 2023.

An incremental value of $1.1 million was determined for the Class C shares and options and will be recognized over the estimated remaining expected term of 1.8 years for the Class C shares and options. The Company recognized $141,794 and $309,391 as share based compensation expense and capitalized $15,717 and $33,024 in the fourth quarter and 2023 respectively.

Detailed information regarding the Class B and Class C shares and options have been disclosed in Note 11 of the financial statements.

DEPLETION AND DEPRECIATION

	Three Months Ended December 31		Year Ended December 31	
(thousands, except per unit amounts)	2023	2022	2023	2022
Depletion and depreciation	$11,294	$7,606	$44,223	$25,045
Per BOE	$19.13	$15.98	$19.04	$16.22

The Company recognized depletion and depreciation expense ("D&D") of $11.3 million ($19.13 per boe) and $44.2 million ($19.04 per boe) for the quarter and the year ended December 31, 2023, respectively compared to $7.6 million ($15.98 per boe) and $25.0 million ($16.22 per BOE) in the same periods of 2022. The D&D expense was based on an internal evaluation of proved and probable reserves and an internal estimate of future development costs.

D&D expense increased in Q4 and 2023 compared to the same periods in 2022 largely due to higher production volume as well as a higher rate. Higher estimates for future development costs, due to additional capital and inflation, are the main contributors to the increase in the per unit D&D expense in 2023.

The D&D expense recognized was comprised primarily of depletion expenses with minor amounts relating 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 amount of reserves added, and production volume. The Company uses total proved plus probable reserves as its depletion base in the calculation of depletion.

EXPLORATION EXPENSE AND IMPAIRMENT

Exploration and Evaluation Assets

North 40 recognized exploration expense of $3.7 million ($6.35 per boe) in Q4 2023 and $4.0 million ($1.73 per boe) for the 2023 year. This compares to $0.2 million ($0.47 per boe) and $0.5 million ($0.34 per boe) in the comparable periods of 2022. Exploration expense relates to undeveloped land expiries and costs related to drilling a test well in 2023.

Property and Equipment

At December 31, 2023 and 2022, there were no indicators of impairment identified and an impairment test was not performed.

FINANCE EXPENSE

	Three Months Ended December 31		Year Ended December 31	
(thousands)	2023	2022	2023	2022
Accretion of decommissioning obligations	$58	$51	$230	$177
Banking fees	17	47	143	98
Interest on leased liabilities	3	6	17	28
Total	$78	$104	$390	$303
Per BOE	$0.13	$0.22	$0.17	$0.20

Finance expense relates to accretion on decommissioning obligations, banking fees 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.

North 40 increased its bank credit facility to $25 million from $8.5 million in late 2022. The increase in banking fees in 2023 is largely due to fees related to this increase as well as higher standby fees.

INCOME TAXES

North 40 recognized a current income tax recovery of $0.9 million in Q4 2023 and current income tax expense of $3.6 million for the year ended December 31, 2023 compared to $0.4 million and $4.5 million in the comparable periods of 2022 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 months and year ended December 31, 2023, a deferred income tax expense of $1.0 million and $2.8 million, respectively, was recognized compared to a deferred income tax expense of $1.9 million and $4.6 million for the comparable periods in 2022.

The following tax pool balances are estimated at December 31, 2023 and 2022:

(thousands)	Maximum Annual Deduction	2023	2022
Canadian oil and gas property expense (COGPE)	10%	$15,110	$15,487
Canadian development expense (CDE)	30%	53,033	40,551
Undepreciated capital cost (UCC)	25%	40,618	27,373
		$108,761	$83,411

NET INCOME AND COMPREHENSIVE INCOME

	Three Months Ended December 31		Year Ended December 31	
(thousands)	2023	2022	2023	2022
Net income and comprehensive income	$945	$8,186	$20,134	$30,865
Per share – basic	$0.01	$0.11	$0.26	$0.41
– diluted	$0.01	$0.10	$0.25	$0.39

North 40 recognized net income and comprehensive income of $0.9 million ($0.01 per basic and diluted share) and $20.1 million ($0.26 per basic and $0.25 per diluted share) for the three months and year ended December 31, 2023, respectively and net income and comprehensive income of $8.2 million ($0.11 per basic and $0.10 per diluted share) and $30.9 million ($0.41 per basic and $0.39 per diluted share) for the comparable periods in 2022.

The decrease in net income for the three months December 31, 2023, as compared to the same period in 2022 is primarily due to an increase in depletion and depreciation, exploration expense, operating and transportation costs, general and administrative costs, and share based compensation partially offset by an increase in revenue, lower royalties and lower current and deferred income tax expense.

The decrease in net income for the year ended December 31, 2023, as compared to the same period in 2022 is primarily due to an increase in depletion and depreciation, operating and transportation costs, exploration expense, royalties, general and administrative costs, and share based compensation partially offset by an increase in revenue, lower current and deferred income tax expense.

CAPITAL EXPENDITURES

Capital expenditures by type and by area for the three months and year ended December 31, 2023 and 2022 were as follows:

	Three Months Ended December 31		Year Ended December 31	
(thousands)	2023	2022	2023	2022
Land and lease rentals [(1)]	$ 892	$1,363	$1,911	$4,151
Seismic and geological	31	1,940	1,925	2,348
Drilling and completion	12,749	5,065	46,796	35,314
Equipping and tie-ins	5,765	9,184	24,878	25,725
Facilities	1,904	8	9,805	8
Office and other	171	214	401	345
Total capital expenditures	$21,512	$17,774	$85,716	$67,891

(1) Net of land fund reimbursements

(thousands)	Three Months Ended December 31 2023	2022	Year Ended December 31 2023	2022
Wayne (formerly Drumheller North)	$ 325	$ 679	$30,699	$21,118
Drumheller	2,122	9,062	19,568	31,585
Sheerness	11,257	-	17,452	-
Tide Lake	5,692	1,244	6,061	1,254
Matziwin	1,796	3,452	7,673	6,396
Princess	156	2,949	2,725	4,543
Other	164	388	1,538	2,995
Total capital expenditures	$21,512	$17,774	$85,716	$67,891

Wells drilled by property were as follows:

	Three Months Ended December 31 2023	2022	Year Ended December 31 2023	2022
Wayne (formerly Drumheller North)	-	-	6	6
Drumheller (1)	-	1	3	7
Sheerness	2	-	3	-
Tide Lake	2	-	2	-
Wintering Hills (1)	-	-	-	1
Matziwin West (2)	-	1	-	1
Matziwin South (2)	-	-	1	-
Makepeace	-	-	-	1
Princess	-	1	1	1
Total	4	3	16	17

(1) Included in Drumheller area
(2) Included in Matziwin area

Fourth quarter 2023 capital expenditures were $21.5 million and includes the following activities:

- freehold lease extensions at Matziwin,
- drilling, completion, and equipping of three wells and the drilling of another. Three of these wells were brought on production in the quarter,
- completion and start-up of water disposal facilities at Drumheller, and
- construction of a pipeline in the Matziwin area.

Fourth quarter 2022 capital expenditures were $17.6 million and includes the following activities:

- freehold lease extension at Drumheller,
- 3D seismic shoot at Drumheller and a 3D seismic purchase at Tide Lake,
- drilling and completion of three wells. One of these wells were brought on production in the quarter,
- re-entry / recompletion operations on three acquired wellbores. One of these wells were brought on production in the quarter and the other two in Q1 2023,
- emission compliance equipment on several existing locations, and
- equipment purchases for 2023 drilling program.

Capital expenditures in 2023 were $85.7 million which included the drilling of 16 wells. The majority of the capital was spent at Wayne where six wells were drilled and an oil battery was constructed. The battery became operational in Q2. Activity at Drumheller included the drilling of three wells, one of which is a water disposal well, and construction of water disposal facilities which became operational in the fourth quarter.

Activities at Sheerness, a new North 40 area in 2023, include acquisition of land leases, purchase of 3D seismic data at Sheerness, and the drilling of three wells. All three wells were brought on production in 2023. Other activities include: drilling of two wells at Tide Lake, one well at each of Matziwin South and Princess, freehold lease extensions, pipeline construction at Matziwin, workover and recompletion operations, and equipment purchases for future locations.

Capital expenditures in 2022 were $67.6 million which included the drilling, completion, equipping and tie-in of 17 wells, re-entry / recompletion of three acquired wellbores (two at Princess and one at Matziwin South), a 3D seismic shoot at Drumheller, 3D seismic purchases at Tide Lake and Wayne and the extension of freehold leases at Matziwin South and Drumheller. The majority of capital has been expended in the greater Drumheller area with seven wells drilled at Drumheller, six wells at Wayne, and one well at Wintering Hills. Capital was also expended to upgrade existing surface facilities to meet new regulatory standards with new wells being added to existing leases.

North 40's land holdings per area at December 31, 2023 and 2022 were as follows:

(acres)	December 31,2023	December 31 2022
Wayne (formerly Drumheller North)	15,630	17,702
Drumheller	57,175	80,390
Sheerness	118,843	7,912
Tide Lake	11,235	10,444
Matziwin	38,731	78,579
Princess	18,858	18,700
Other	25,008	10,851
Total	285,480	224,578

The land holdings consist of 68% crown and 32% freehold leases at December 31, 2023. Working interest in North 40's land holdings is 100 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 $7.6 million at December 31, 2023. ($6.3 million at December 31, 2022).

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. A risk-free rate of 3.05% (3.29% at December 31, 2022) and an inflation rate of 2.20% (2.20% at December 31, 2022) were used to calculate the best estimate of the decommissioning obligation. The increase in the decommissioning obligation at December 31, 2023, compared to December 31, 2022, is primarily due to new liabilities recognized for wells drilled and new facilities.

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2023, the Company had no drawn debt and a working capital deficit of $6.1 million comprised of $8.0 million in cash and a working capital deficit of $14.1 million. All activities to date have been funded with proceeds from the Company's initial equity financing, cash flow from operations, working capital, land fund reimbursements and interest income on cash balances.

At December 31, 2023, the Company had a $25.0 million revolving demand operating facility with a Canadian chartered bank. The facility bears interest based on the prime rate or banker's acceptance 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 0.25%. The Company has a letter of credit outstanding for $0.1 million at December 31, 2023.

The facility includes a financial covenant that requires the working capital, adjusted for unrealized hedging, the current portion of debt, and the undrawn availability under the facility, to not be less than 1.0 at each fiscal quarter end. The Company was in compliance with this covenant at December 31, 2023. The facility also includes a covenant that the Company maintain a liability management rating (LMR) established by each applicable energy regulator of not less than 2. The Company's LMR at December 31, 2023 is 18.3. 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 banker's acceptances. The credit facility is subject to periodic review at the lenders' discretion. The next review date has been set for May 31, 2024.

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, 2024. The agreement includes a funding limit of $14 million, which may be increased at the sole discretion of the party. At December 31, 2023, there is $3.8 million remaining on the funding limit.

Subsequent to December 31, 2023, the funding limit on the Royalty Acquisition Agreement was increased to $17 million and term extended to October 31, 2025.

RESERVE INFORMATION

North 40’s reserves have been internally evaluated by the Company’s engineers as at December 31, 2023 in accordance with reserve definitions, standards and procedures contained in the Canadian Oil and Gas Evaluation Handbook (COGE).

The following table summarizes North 40’s Company Interest reserves at December 31, 2023:

(Company Interest)	**Oil and Liquids (Mbbls)**	**Natural Gas (MMcf)**	**Oil Equivalent (Mboe)**
Proved developed producing	3,544	11,161	5,404
Proved developed non-producing	54	1,401	287
Proved undeveloped	2,875	5,965	3,869
Total proved	6,473	18,527	9,561
Probable	3,103	8,330	4,492
Total proved plus probable	9,576	26,857	14,052

The following table summarizes changes in reserves during 2023:

(Mboe)	**Proved Producing**	**Total Proved**	**Total Probable**	**Total Proved & Probable**
December 31, 2022	4,432	8,129	4,400	12,530
Production – 2023	(1,948)	(2,323)	-	(2,323)
Additions	1,271	2,610	831	3,441
Net acquisitions	-	-	-	-
Technical revisions	1,649	1,144	(739)	404
December 31, 2023	5,404	9,560	4,492	14,052

The following table summarizes net reserves values at December 31, 2023:

NET PRESENT VALUES OF FUTURE NET CASH FLOW (BEFORE INCOME TAXES)

($ Million)	**0%**	**5%**	**10%**	**15%**	**20%**
Proved developed producing	136	121	108	98	90
Proved developed non-producing	3	3	3	2	2
Proved undeveloped	99	72	55	43	34
Total proved	238	196	166	143	126
Probable	136	98	74	59	48
Total proved plus probable	374	294	240	202	174

Abandonment and reclamation costs for; inactive wells with no reserves assigned, for pipelines and infrastructure and for multi-well batteries have been included within the reserve evaluation. These are also included within the decommissioning obligations in the statements of financial position.

Notes:

The following reserve definitions are as set out in National Instrument 51-101 and the Canadian Oil and Gas Evaluation Handbook (COGE):

“Company Interest” reserves are the sum of the of Company Gross plus Company Royalty Interest reserves.

“Company Royalty Interest” reserves are the net reserves received as a result of a royalty or carried interest.

“Gross” means North 40’s interest in operated and non-operated production and reserves before the deduction of royalties.

“Net” means North 40’s interest in operated and non-operated production and reserves after deduction of royalty obligations.

“Reserves” are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

"Proved Reserves" are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the targeted level of certainty.

"Probable Reserves" are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less that the sum of the estimated Proved plus Probable Reserves. At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves is the targeted level of certainty.

"Proved Developed Reserves" are those Reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g. when compared to the cost of drilling a well) to put the Reserves on production. The developed category may be subdivided into producing and non-producing.

"Developed Producing Reserves" are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or. If shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

"Developed Non-Producing Reserves" are those Reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

"Undeveloped Reserves" are those Reserves expected to be recovered from known accumulations where a significant expenditure (e.g. when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the Reserves classification (Proved, probable, possible) to which they are assigned.

The forecast cost and price assumptions assume the continuation of current laws and regulations and increases in wellhead selling prices and take into account inflation with respect to future costs. The following table is a summary of pricing assumptions based on the January 1, 2024 price forecast of McDaniels & Associates Consultants Ltd. and North 40's estimates.

Summary of Pricing Assumptions
Effective December 31, 2023
Forecast Price and Costs

Forecast	Oil			Gas		
Year	WTI Cushing Oklahoma ($US)	Edmonton Light ($C)	N40 Oil Price ($C)	Henry Hub ($US)	AECO Spot ($C)	N40 Gas Price ($C)
		($/bbl)			($/mmbtu)	
2024	72.50	92.00	82.96	2.75	2.25	2.64
2025	73.95	93.84	84.73	3.32	3.06	3.49
2026	75.43	95.72	86.42	3.90	3.90	4.38
2027	76.94	97.63	88.23	3.98	3.98	4.45
2028	78.48	99.58	89.96	4.06	4.06	4.55
2029	80.05	101.58	91.75	4.14	4.14	4.64
2030	81.65	103.61	93.58	4.22	4.22	4.73
2031	83.28	105.68	95.45	4.31	4.31	4.82
2032	84.95	107.79	97.36	4.39	4.39	4.91

Note: Inflation rate assumption is 2% per annum.

CAPITAL EFFICIENCIES

	2023	3- Year Average
Finding, development, and acquisition costs [1]		
Total proved ($ per boe)	$32.10	$27.55
Proved plus probable reserves ($ per boe)	$27.64	$22.54
Recycle Ratio [2] (times)	1.2	1.7

[1] Includes future development costs of $66.4 million on a proved basis and $105.6 million on a proved plus probable basis.
[2] Based on the Company's operating netbacks and F&D costs for proved plus probable reserves.

SELECTED QUARTERLY INFORMATION

Three Months Ended	Dec 31 2023	Sept 30 2023	Jun 30 2023	Mar 31 2023	Dec 31 2022	Sept 30 2022	Jun 30 2022	Mar 31 2022
FINANCIAL								
Petroleum and natural gas revenue	$34,594	$44,318	$33,839	$30,668	$34,029	$28,699	$30,675	$22,930
Funds flow from operations [(1)]	$17,289	$22,560	$16,989	$15,755	$18,206	$15,011	$16,467	$11,826
Per share – basic	$0.23	$0.29	$0.22	$0.21	$0.24	$0.20	$0.22	$0.16
Per share – diluted	$0.21	$0.28	$0.21	$0.20	$0.23	$0.18	$0.20	$0.15
Net income	$ 945	$9,306	$4,572	$5,311	$8,186	$6,291	$10,222	$6,166
Per share – basic	$0.01	$0.12	$0.06	$0.07	$0.11	$0.08	$0.14	$0.08
Per share – diluted	$0.01	$0.11	$0.06	$0.07	$0.10	$0.08	$0.13	$0.08
Capital expenditures [(2)]	$21,512	$17,740	$18,656	$27,808	$17,774	$20,385	$18,850	$10,882
Working capital surplus (deficiency) at end of period [(3)]	($6,114)	($1,857)	($6,644)	($4,946)	$7,139	$6,737	$12,141	$14,401
Common shares outstanding end of period	76,624	76,624	76,624	76,624	76,624	76,624	75,340	75,250
OPERATING								
Sales volumes								
Oil and liquids (bbls/day)	4,076	4,740	4,203	3,544	3,391	2,656	2,155	2,020
Natural gas (mcf/day)	14,052	12,550	12,767	13,907	10,693	9,897	9,363	10,122
Total (boe/day) [(4)]	6,418	6,832	6,331	5,862	5,174	4,306	3,715	3,707
% Oil and liquids	64	69	66	60	66	62	58	54
Commodity prices realized (before pipeline tariffs)								
Oil and liquids ($/bbl)	87.40	97.95	84.41	86.71	96.05	104.34	126.40	104.13
Natural gas ($/mcf)	2.54	2.92	2.72	3.60	5.42	4.59	7.91	5.26
Total ($/boe)	61.08	73.33	61.53	60.96	74.17	74.91	93.24	71.10
Operating netback [(5)] ($/boe)	30.74	40.47	32.91	32.96	42.56	41.97	56.99	41.20
Funds flow from operations netback ($/boe) [(1)]	29.28	35.89	29.49	29.86	38.25	37.89	48.71	35.45
Net wells drilled	4.0	3.0	3.0	6.0	3.0	5.0	5.0	4.0
Net acres of land at end of period	285,480	297,608	307,909	191,849	224,578	221,828	221,777	235,266

(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*

Significant factors and trends that have impacted the Company's results during the above periods include:

- Organic growth in production volume from the Company's drilling program.
- In early 2020, crude oil prices experienced a rapid and sudden decline as the COVID-19 global pandemic began to negatively impact crude oil demand and a dispute amongst major oil producing nations resulted in additional crude oil supply. Crude oil prices began a gradual increase mid-year supported by coordinated production cuts by OPEC and OPEC+, voluntary production curtailments by producers and reduced drilling activity. In 2021, global demand, notably in large economies such as the United States and China, was increasing in response to continued recovery from the COVID-19 pandemic, vaccination programs and significant adherence to production cuts by OPEC and OPEC+. This was partially offset by new waves of COVID-19 and the spread of variant cases.
- The volatility in commodity prices and the resultant effect on revenue, funds flow from operations, and net income.
- Current income tax expense was first recognized in Q1 2022.

SELECTED ANNUAL INFORMATION

	2023	2022	2021	2020	2019
FINANCIAL					
Petroleum and natural gas revenue	$143,418	$116,333	$63,880	$30,114	$56,711
Funds flow from operations [(1)]	$72,594	$61,509	$36,390	$14,463	$33,845
Per share – basic	$0.95	$0.81	$0.48	$0.19	$0.45
Per share – diluted	$0.90	$0.77	$0.47	$0.19	$0.42
Net income (loss)	$20,134	$30,865	$15,301	$(910)	$11,236
Per share – basic	$0.26	$0.41	$0.20	$(0.01)	$0.15
Per share – diluted	$0.25	$0.39	$0.20	$(0.01)	$0.14
Capital expenditures [(2)]	$85,716	$67,891	$35,888	$16,663	$40,072
Working capital surplus (deficiency) [(3)] at end of period	($6,114)	$7,139	$13,486	$13,186	$15,518
Common shares outstanding end of period	76,624	76,624	75,250	75,250	75,250
OPERATING					
Sales volumes					
Oil and liquids (bbls/day)	4,144	2,560	2,104	1,749	2,486
Natural gas (mcf/day)	13,317	10,020	6,305	4,955	6,988
Total (boe/day) [(4)]	6,363	4,230	3,154	2,575	3,651
% Oil and liquids	65	61	67	68	68
Commodity prices realized (before pipeline tariffs)					
Oil and liquids ($/bbl)	89.54	106.16	74.04	43.64	61.03
Natural gas ($/mcf)	2.95	5.75	4.22	2.59	1.88
Total ($/boe)	64.48	77.88	57.83	34.63	45.17
Operating netback [(5)] ($/boe) (before hedging settlements)	34.41	45.28	33.94	18.22	27.03
Hedging Settlements	-	-	-	(0.98)	-
Operating netback ($/boe) (after hedging settlements)	34.41	45.28	33.94	17.24	27.03
Funds from operations netback ($/boe) [(1)]	31.25	39.84	31.61	15.35	25.44
Net wells drilled	16.0	17.0	14.0	6.0	14.0
Net acres of land at end of period	285,480	224,578	256,346	255,254	283,195

(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*

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INDEPENDENT AUDITOR'S REPORT

To the Shareholders and the Board of Directors of North 40 Resources Ltd.

Opinion

We have audited the financial statements of North 40 Resources Ltd. (the "Company"), which comprise:

- the statement of financial position as at December 31, 2023
- the statement of net income and comprehensive income for the year then ended
- the statement of changes in equity for the year then ended
- the statement of cash flow for the year then ended
- and notes to the financial statements, including a summary of material accounting policy information

(Hereinafter referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2023, and its financial performance and its cash flows for the year then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board (IASB).

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the **"*Auditor's Responsibilities for the Audit of the Financial Statements*"** section of our auditor's report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

KPMG LLP, an Ontario limited liability partnership and member firm of the KPMG global organization of independent member firms affiliated with KPMG International Limited, a private English company limited by guarantee. KPMG Canada provides services to KPMG LLP.

Other Information

Management is responsible for the other information. Other information comprises the information included in Management's Discussion and Analysis.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information, other than the financial statements and the auditor's report thereon, included in Management's Discussion and Analysis as at the date of this auditor's report.

If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditor's report.

We have nothing to report in this regard.

Responsibilities of Management and Those Charged with Governance for the Financial Statements

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board (IASB), and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

  The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.

- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.

- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor's report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor's report. However, future events or conditions may cause the Company to cease to continue as a going concern.

- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
April 3, 2024

NORTH 40

RESOURCES LTD.

Financial Statements
For the year ended December 31, 2023

North 40 Resources Ltd.
Statements of Financial Position

As at	December 31 2023	December 31 2022
($ thousands)		
ASSETS		
Current Assets		
Cash	8,036	19,066
Accounts receivable	11,693	10,853
Current income taxes (Note 8)	487	-
Prepaids and deposits	1,036	691
Total Current Assets	21,252	30,610
Exploration and evaluation assets (Note 4)	19,275	23,318
Property and equipment (Note 5)	169,382	126,595
Total Assets	**209,909**	**180,523**
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	27,366	18,923
Current income taxes (Note 8)	-	4,548
Total Current Liabilities	27,366	23,471
Lease liabilities (Note 10)	118	248
Decommissioning obligations (Note 9)	7,644	6,273
Deferred income taxes (Note 14)	16,593	13,796
Total Liabilities	51,721	43,788
Shareholders' Equity		
Share capital (Note 11)	76,245	76,245
Contributed surplus	4,661	3,342
Retained earnings	77,282	57,148
Total Shareholders' Equity	158,188	136,735
Total Liabilities and Shareholders' Equity	**209,909**	**180,523**

Subsequent Events (Notes 11,17, and 18)

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

Approved on behalf of the Board:

Margaret McKenzie, Director

Tyson Birchall, Director

North 40 Resources Ltd.

Statements of Net Income and Comprehensive Income

	Years ended December 31	
	2023	**2022**
($ thousands except per share amounts)		
Revenue		
Petroleum and natural gas revenue (Note 12)	143,418	116,333
Less: Royalties	31,610	28,144
	111,808	88,189
Interest income	523	376
Other income (Note 5)	-	166
	112,331	88,731
Expenses		
Operating	26,049	15,340
Transportation	5,828	2,949
General and administrative	4,071	3,757
Share based compensation (Note 11)	1,183	171
Depletion and depreciation (Note 5)	44,223	25,045
Exploration expense (Note 4)	4,027	523
Settlement expense (Note 6)	-	502
Finance expense	390	303
Total expenses	85,771	48,590
Income before taxes	26,560	40,141
Current income tax expense (Note 8)	3,629	4,548
Deferred income tax expense (Note 14)	2,797	4,728
Income taxes	6,426	9,276
Net Income and Comprehensive Income	**20,134**	**30,865**
Net Income per share (Note 13)		
Basic	$0.26	$0.41
Diluted	$0.25	$0.39

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

North 40 Resources Ltd.
Statements of Changes in Equity

	Share Capital	Contributed Surplus	Retained Earnings	Total Equity
($ thousands)				
Balance as at December 31, 2021	**75,416**	**3,832**	**26,283**	**105,531**
Net income	-	-	30,865	30,865
Issue of share capital	153	-	-	153
Transferred on conversion of Class B's and C's	676	(676)	-	-
Share based compensation (Note 11)	-	186	-	186
Balance as at December 31, 2021	**76,245**	**3,342**	**57,148**	**136,735**
Balance as at December 31, 2022	**76,245**	**3,342**	**57,148**	**136,735**
Net income	-	-	20,134	20,134
Share based compensation (Note 11)	-	1,319	-	1,319
Balance as at December 31, 2023	**76,245**	**4,661**	**77,282**	**158,188**

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

North 40 Resources Ltd.

Statements of Cash Flow

	Years ended December 31	
	2023	**2022**
($ thousands)		
Cash provided by (used in):		
Operating activities		
Net income for the year	20,134	30,865
Adjusted for:		
Depletion and depreciation (Note 5)	44,223	25,045
Exploration expense (Note 4)	4,027	523
Accretion expense (Note 9)	230	177
Share based compensation (Note 11)	1,183	171
Deferred income tax expense (Note 14)	2,797	4,728
	72,594	61,509
Net change in non-cash working capital (Note 16)	(2,894)	6,030
	69,700	67,539
Financing activities		
Issue of share capital (Note 11)	-	153
Repayment of lease liabilities (Note 10)	(132)	(117)
	(132)	36
Investing activities		
Exploration and evaluation expenditures (Note 4)	(6,417)	(8,905)
Property and equipment expenditures (Note 5)	(79,299)	(58,986)
Net change in non-cash working capital (Note 16)	5,118	5,430
	(80,598)	(62,461)
Change in cash	(11,030)	5,114
Cash, beginning of year	19,066	13,952
Cash, end of year	**8,036**	**19,066**

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

North 40 Resources Ltd.
Notes to the Financial Statements

December 31, 2023 and 2022 *(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 financial statements have been prepared by management in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IASB").

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 April 3, 2024.

(b) Basis of measurement

These financial statements have been prepared on a going concern basis under the historical cost basis, which contemplates the realization of assets and settlement of liabilities in the normal course of business as they become due.

(c) Functional and presentation currency

These financial statements are presented in Canadian dollars, which is the Company's functional currency.

(d) Use of estimates and judgements

The preparation of financial statements in conformity with IFRS Accounting Standards as issued by the IASB requires management to make judgements, assumptions and estimates that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the financial statements and revenues and expenses for the periods reported. Actual results may differ from such estimates. Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the period in which the estimates are revised and in any future years affected.

Significant estimates and judgements made by management in the preparation of financial statements are outlined below.

(i) Decommissioning obligations

Decommissioning obligations and the related accretion expense require the use of estimates with respect to the amount and timing of decommissioning expenditures. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, market conditions, discovery and analysis of site conditions and changes in technology. Changes to assumptions related to future expected costs, discount rates and timing may have a material impact on the amounts presented.

(ii) Impairment indicators

Judgements are required to assess when impairment indicators exist, and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, which are dependent upon certain assumptions including: production rates, future oil and natural gas prices, future operating and transportation costs, royalties, discount rates and other relevant assumptions. Assets are grouped into CGUs for purposes of impairment assessment.

(iii) Income taxes

Tax regulations and legislation and the interpretations thereof are subject to change. The deferred income tax calculation recognizes the extent that temporary differences will be realized (asset) or payable (liability) in future periods. The calculation of deferred income tax involves a significant amount of estimation including an evaluation of when the temporary differences will reverse, an analysis of the amount of future taxable income and the application of tax laws. Changes in tax regulations and legislation and the other assumptions listed are subject to measurement uncertainty.

(iv) Exploration and evaluation assets

The application of the Company's accounting policy for exploration and evaluation assets requires management to make certain judgements in determining whether it is likely that future economic benefits exist when activities have not reached a stage where technical feasibility and commercial viability can be reasonably determined.

(v) Reserves

Estimates of recoverable quantities of proved and probable reserves include estimates and assumptions regarding production volumes, future commodity prices, exchange rates, discount rates, timing of future development costs and production and transportation costs for future cash flows as well as the interpretation of complex geological and geophysical models and data. Changes in reported reserves can affect the impairment of assets, the reported amount of decommissioning obligations, the economic feasibility of exploration and evaluation assets and the amounts reported for depletion of property and equipment. Reserves estimates were prepared by internal engineers in accordance with definitions prescribed by the Canadian Oil and Gas Evaluations Handbook and National Instrument 51-101.

(vi) Share-based compensation

Share based compensation recorded pursuant to share based compensation plans are subject to estimated fair values based on estimated share price, risk free interest rate, forfeiture rates, volatility, and the future attainment of performance criteria, if any.

3. MATERIAL ACCOUNTING POLICIES

(a) Exploration and Evaluation Assets

(i) Capitalization

All costs incurred after the rights to explore an area have been obtained, such as geological and geophysical costs, other direct costs of exploration (drilling, testing, and evaluating the technical feasibility and commercial viability of extraction) and appraisal, are accumulated and capitalized as exploration and evaluation assets.

Costs incurred prior to acquiring the legal rights to explore are expensed as incurred.

(ii) Depletion

Exploration and evaluation costs are not depleted prior to the conclusion of appraisal activities. At the completion of appraisal activities, if technical feasibility is demonstrated and commercial reserves are discovered, then the carrying value of the relevant exploration and evaluation asset will be reclassified as a petroleum and natural gas asset into the CGU to which it relates, but only after the carrying value of the relevant exploration and evaluation asset has been assessed for impairment and, where appropriate, its carrying value adjusted. The technical feasibility and commercial viability of extracting a resource is determinable based on several factors including the assignment of proved and probable reserves, completion of drilling and testing. Upon determination, exploration and evaluation costs attributable to those reserves are reclassified to depletable property and equipment. If it is determined that technical feasibility and commercial viability have not been achieved in relation to the exploration and evaluation assets appraised, all other associated costs are written down to the recoverable amount in net income.

Expired land leases included as undeveloped land in exploration and evaluation assets are recognized in exploration and evaluation cost in net income upon expiry.

(iii) Impairment

If and when facts and circumstances indicate that the carrying value of an exploration and evaluation asset may exceed its recoverable amount, an impairment review is performed. For exploration and evaluation assets, when there are such indications, an impairment test is carried out. In addition, exploration and evaluation assets are tested for impairment when they are transferred to property and equipment. The equivalent carrying value of the CGU is compared against the recoverable amount of the CGU and any resulting impairment loss is written off to net income. The recoverable amount is the greater of fair value, less costs to sell, or value in use.

Impairments of exploration and evaluation assets are only reversed when there is significant evidence that the impairment has been reversed but only to the extent of what the carrying amount would have been had no impairment been recognized.

(b) Property and Equipment

(i) Capitalization

The Company's property and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The development and production assets are grouped into CGUs for the purpose of impairment testing.

The initial cost of an asset comprises its purchase price or construction cost, any costs directly attributable to bringing the asset into operation, the initial estimate of any decommissioning liability, if any, and for qualifying assets, borrowing costs. The purchase price or construction cost is the aggregate amount paid and the fair value of any other consideration given to acquire the asset. Non-monetary exchanges of assets are measured at fair value unless the exchange transaction lacks commercial substance or the fair value of neither the asset received, nor the asset given up is reliably measurable. The cost of the acquired asset is measured at the fair value of the asset given up unless the fair value of the asset received is more reliable. The gain or loss on derecognition of the asset given up is recognized in net income.

Expenditures on major maintenance, inspections or overhauls are capitalized when the item enhances the life or performance of an asset above its original standard. Where an asset or part of an asset that was separately depreciated is replaced and it is probable that future economic benefits associated with the item will flow to the Company, the expenditure is capitalized and the carrying amount of the replaced asset is derecognized. All other maintenance expenditures are expensed as incurred.

(ii) Depletion and Depreciation

The net carrying amount of development and production assets is depleted using the unit-of-production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account estimated future development costs necessary to bring those reserves into production. These estimates are reviewed at least annually.

Proved and probable reserves are estimated annually using internal reserve engineering reports in accordance with Canadian Oil and Gas Evaluation Handbook (COGE) and represent the estimated quantities of crude oil and natural gas which geological, geophysical, and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible. There should be a 50 percent statistical probability that the actual quantity of recoverable reserves will be more than the amount estimated as proved and probable and a 50 percent statistical probability that it will be less. The equivalent statistical probabilities for the proved component of proved and probable reserves are 90 percent.

Such reserves may be considered commercially producible if management has the intention of developing and producing them and such intention is based upon a reasonable assessment of the future economics of such production, a reasonable expectation that there is a market for all or substantially all the expected crude oil and natural gas production, and evidence that the necessary production, transmission and transportation facilities are available or can be made available.

Corporate assets are stated in the statement of financial position at cost less accumulated depreciation. Depreciation is calculated on a declining balance method to write off costs of these assets, less estimated residual values, over their estimated residual lives. The useful lives of the Company's corporate assets are as follows:

Depreciation methods, useful lives and residual values are reviewed at least annually.

(iii) Impairment

The carrying amounts of the Company's property and equipment are reviewed at each reporting period to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated.

For the purpose of impairment testing, assets are grouped into CGUs, the smallest group of assets that generate cash inflows from continuing use that are largely independent from the cash inflows of other assets or groups of assets. The recoverable amount of a CGU is the greater of its value in use and its estimated fair value less costs to sell.

In estimating value in use, the projected future cash flow from proved and probable reserves and undeveloped properties are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and risks specific to the assets.

Fair value less cost to sell is determined as the amount that would be obtained from the sale of a CGU in an arm's length transaction between knowledgeable and willing parties. The fair value less costs to sell of oil and gas assets is generally determined as the net present value of the estimated future cash flows expected to arise from the CGU. These cash flows are discounted by an appropriate discount rate which would be applied by such a market participant to arrive at a net present value of the CGU.

An impairment loss is recognized if the carrying amount of an asset or CGU exceeds its estimated recoverable amount. Impairment losses are recognized in the statement of income (loss) and comprehensive income (loss). Impairment losses recognized in respect of CGUs are allocated to reduce the carrying amounts of the assets in the unit on a pro rata basis.

(c) Provisions

A provision is recognized if, as a result of a past event, the Company has a present legal or constructive obligation that can be estimated reliably, and it is probable that an outflow of economic benefits will be required to settle the obligation. Provisions are determined by discounting the expected future cash flow at a pretax rate that reflects current market assessments of the time value of money and the risks specific to the liability. Provisions are not recognized for future operating losses.

a. Decommissioning Obligations

The Company's activities give rise to dismantling, decommissioning, and site disturbance remediation activities. Provisions are made for the estimated costs of abandonment and site restoration and capitalized to the relevant asset category.

Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the date of the statement of financial position, using a risk free discount rate. Subsequent to initial measurement the obligation is adjusted at the end of each period to reflect the passage of time and changes to the estimated future cash flows underlying the obligation.

The increase in the provision due to the passage of time (accretion) is recognized as finance expense whereas increases or decreases due to changes in the estimated future cash flows are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(d) Financial Instruments

Recognition and Measurement

Trade receivables issued are initially recognized when they are originated. All other financial assets and financial liabilities are initially recognized when the Company becomes a party to the contractual provisions of the instrument.

A financial asset or liability (unless it is a trade receivable without a significant financing component) is initially measured at fair value plus, for an item not at fair value through profit or loss, transaction costs that are directly attributable to its acquisition or issue. A trade receivable without a significant financing component is initially measured at the transaction price.

Classification of Financial Assets and Liabilities

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost, fair value through other comprehensive income (FVOCI), or fair value through profit or loss (FVTPL). The classification of financial assets under IFRS 9 is generally based on the business model in which a financial asset is managed and its contractual cash flow characteristics.

The following table shows the original measurement categories under IFRS 9 for each class of the Company's financial assets and financial liabilities.

	Measurement Category	
Financial Instrument	**Classification**	**Subsequent Measurement**
Cash	Amortized cost	Amortized cost using effective interest method
Accounts receivables	Amortized cost	Amortized cost using effective interest method
Accounts payable and accrued liabilities	Amortized cost	Amortized cost using effective interest method

(e) Share Based Compensation Expense

The fair value of share-based compensation granted to directors, officers, employees, and consultants is measured on the issue date using the Black Scholes pricing model. The fair value is subsequently recognized as share-based compensation expense over the vesting period with a corresponding increase to contributed surplus. Upon conversion of the Class B and Class C shares to common shares, consideration paid by the Class B and Class C shareholders and the value in contributed surplus pertaining to the converted Class B and Class C shares are recorded as share capital. A forfeiture rate is estimated on the issue date with the difference between the estimated and actual forfeitures adjusted through share-based compensation expense.

(f) Revenues

Revenue Recognition

Under IFRS 15, revenue from the sale of crude oil, natural gas and natural gas liquids is measured based on the consideration specified in contracts with customers and recognizes revenue when it transfers control of the product to the purchaser. This is generally at the time the customer obtains legal title to the product and when it is physically transferred to the delivery mechanism agreed with the purchaser, often pipelines or other transportation methods.

(g) Income Taxes

Income tax expense is comprised of current and deferred tax. Income tax expense is recognized in income or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity. Deferred income tax assets and liabilities are recognized as non-current.

Current tax is the expected tax payable in respect of taxable income, using tax rates enacted or substantially enacted at the reporting date as well as adjustments to tax payable in respect of previous years. Deferred tax is recognized using the balance sheet method whereby temporary differences between carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes are calculated. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date. Deferred tax assets are recognized to the extent that it is probable that future taxable profits will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and reduced to the extent that it is no longer probable that the related tax benefit will be realized.

Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset and they relate to income taxes levied by the same tax authority on the same taxable entity, or on different taxable entities, when the intent is to settle current tax assets and liabilities on a net basis or the tax assets and liabilities are expected to be realized simultaneously.

(h) Earnings Per Share

Earnings per share is presented for basic and diluted earnings. Basic per share information is computed by dividing the net income (loss) for the period attributable to equity owners of the Company by the weighted average number of common shares outstanding during the period. The weighted average number of common shares for diluted earnings per share information is calculated using the treasury stock method whereby it is assumed that proceeds obtained upon exercise of Class B and Class C shares and options issued under the Company’s Share-Based Compensation Plan would be used to purchase common shares at the average market price during the period. Under the treasury stock method share-based compensation plans have a dilutive effect only when the average market price of the common shares during the period exceeds the exercise price of the shares (shares are “in-the-money”). Exercise of in-the-money Class B and Class C shares is assumed at the beginning of the year or date of issuance, if later. Should the Company have a net loss for the period, Class B and Class C shares would be anti-dilutive and therefore will have no effect on the determination of loss per share.

4. EXPLORATION AND EVALUATION ASSETS

($)	December 31 2023	December 31 2022
Balance, beginning of period	23,318	21,422
Additions	6,417	8,905
Exploration expense	(4,027)	(523)
Transferred to property and equipment	(6,433)	(6,485)
Balance, end of period	19,275	23,318

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 relates to undeveloped land expiries and costs related to drilling a test well.

5. PROPERTY AND EQUIPMENT

($)	December 31 2023	December 31 2022
Property and equipment, at cost	294,085	207,099
Accumulated depletion and depreciation	(124,727)	(80,504)
Net book value, end of period	169,358	126,595

Reconciliations of movements during the period:		
Cost, beginning of period	207,099	142,002
Accumulated depletion and depreciation, beginning of period	(80,504)	(55,459)
Net book value, beginning of period	126,595	86,543
Additions	79,436	59,001
Transferred from exploration and evaluation assets	6,433	6,486
Changes in decommissioning obligations (Note 9)	1,141	(390)
Depletion and depreciation	(44,223)	(25,045)
Net book value, end of period	169,382	126,595

Included in the calculation of depletion was an estimate for future development costs of $105.6 million at December 31, 2023 ($85.0 million at December 31, 2022). An estimated future salvage value of $7.0 million was excluded from the calculation of depletion at December 31, 2023 ($5.5 million at December 31, 2022).

Included in the December 31, 2023 property and equipment balance is the right-of-use asset of $0.1 million ($0.2 million at December 31, 2022).

Included in additions is capitalized general and administrative expenses of $0.4 million ($0.3 million in 2022).

In 2022, included in depletion and depreciation, is an impairment charge of $0.2 million related to equipment failure at a Drumheller North battery. In addition other income of $0.2 million was recognized in 2022 for estimated expected insurance proceeds for the damaged equipment.

At December 31, 2023, and December 31, 2022, there were no indicators of impairment identified and an impairment test was not performed.

6. SETTLEMENT EXPENSE

In 2022, North 40 recognized an obligation for $0.5 million to settle a dispute with another producer who had claimed a North 40 well was producing natural gas from that party's natural gas mineral rights.

7. CREDIT FACILITY

At December 31, 2023, the Company had a $25.0 million revolving demand operating facility with a Canadian chartered bank. The facility bears interest based on the prime rate or banker's acceptance 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 0.25%. The Company has a letter of credit outstanding for $0.1 million at December 31, 2023.

The facility includes a financial covenant that requires the working capital, adjusted for unrealized hedging, the current portion of debt, and the undrawn availability under the facility, to not be less than 1.0 at each fiscal quarter end. The Company was in compliance with this covenant at December 31, 2023. The facility also includes a covenant that the Company maintain a liability management rating (LMR) established by each applicable energy regulator of not less than 2. The Company's LMR at December 31, 2023 is 18.3. 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 banker's acceptances. The credit facility is subject to periodic review at the lenders' discretion. The next review date has been set for May 31, 2024.

8. CURRENT INCOME TAXES

($)	December 31 2023	December 31 2022
Balance, beginning of period	4,548	-
Current income tax expense	3,629	4,548
Payments [1]	(8,664)	-
Balance, end of period	(487)	4,548

[1] *Includes instalments.*

9. 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 Company estimates the total uninflated undiscounted amount of cash flows required to settle its decommissioning obligations is approximately $9.2 million ($7.4 million at December 31, 2022). A risk-free rate of 3.05% and an inflation rate of 2.20% were used to calculate the best estimate of the decommissioning obligations compared to 3.29% and 2.20% respectively which were the rates used at December 31, 2022.

A reconciliation of the decommissioning obligations is provided below.

($)	December 31 2023	December 31 2022
Balance, beginning of period	6,273	6,486
Liabilities incurred	1,197	1,398
Change in estimates	(56)	(1,788)
Accretion expense	230	177
Balance, end of period	7,644	6,273

10. LEASE LIABILITIES

The Company incurs lease payments related to office facilities. For the year ended December 31, 2023, finance expense of $16,917 ($27,952 for the year ended December 31, 2022) and repayment of lease liabilities of $129,351 ($117,316 for the year ended December 31, 2022) were recognized for a total cash outflow of $146,268 ($146,268 in 2022). Lease obligations contractually expire in January 2025.

11. 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		**December 31 2023**		**December 31 2022**
	Number	**Amount**	**Number**	**Amount**
Common Shares				
Balance, beginning of period	76,624	$76,093	75,250	$75,228
Issued for cash	-	-	90	153
Issued on conversion of Class B's and C's	-	-	1,284	712
Balance, end of period	76,624	$76,093	76,624	$76,093
Class B Common Non-Voting Shares				
Balance, beginning of period	4,870	$49	6,370	$64
Converted to common shares	-	-	(1,500)	($15)
Balance, end of period	4,870	$49	4,870	$49
Class C Common Non-Voting Shares				
Balance, beginning of period	10,380	$103	12,480	$124
Converted to common shares	-	-	(1,050)	(11)
Forfeited	-	-	(1,050)	(10)
Balance, end of period	10,380	$103	10,380	$103
Total		$76,245		$76,245

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 2026 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 December 31, 2023, 5,483,500 Class B shares and options have vested (5,265,083 at December 31, 2022).

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, 2022	932,750	$0.61
Granted	619,250	0.81
Exercised	(37,500)	(0.77)
Forfeited	(112,500)	(0.51)
Balance, December 31, 2022	1,402,000	$0.70
Granted	400,000	1.00
Forfeited	(70,000)	(0.61)
Balance, December 31, 2023	1,732,000	$0.77

In 2022, 1,500,000 Class B shares and 37,500 options on Class B shares were converted into common shares through a cashless exercise.

The fair market value of each Class B option granted in 2023 was estimated on the date of issue using the Black-Scholes pricing model and the following weighted average assumptions in the calculations:

Weighted average risk-free interest rate (%)	4.48
Expected life (years)	2.0- 3.0
Estimated volatility of underlying common shares (%)	58
Share Price ($)	2.00
Estimated forfeiture rate (%)	nil

The Company recognized share-based compensation expense of $775,921 related to the Class B shares and options for the year ended December 31, 2023 ($118,925 in 2022) and capitalized $97,079 ($8,886 in 2022).

In June 2023, the Board of Directors extended the expiry of certain Class B shares and options to September 2026 from September 2023. The term extension is a modification under IFRS and requires an update to the calculation of share-based compensation expense. The incremental value of $0.6 million was determined for the vested Class B shares and options. This incremental value is recognized immediately and $0.5 million has been expensed and $0.1 million has been capitalized.

The incremental value is the difference in value immediately before the modification (term extension) and immediately after the modification. The following assumptions were used in the calculations:

	Before Modification	After Modification
Weighted average risk-free interest rate (%)	4.83	4.55
Expected life (years)	0.5	1.8
Estimated volatility of underlying common shares (%)	60	60
Share Price ($)	1.99	1.99
Estimated forfeiture rate (%)	nil	nil

On January 1, 2024, the Company granted 565,000 options on Class B shares with an exercise price of $1.00 per share to officers, employees and consultants.

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
2,242,333	$1.50	$1.00
2,242,333	$2.00	$1.15
2,242,333	$2.25	$1.30
2,242,333	$2.50	$1.45
2,242,333	$2.75	$1.60
2,242,333	$3.00	$1.75

In June 2023, the Board of Directors eliminated the terms to increase both the liquidity event price and the conversion price by eight percent compounded annually beginning in June 2023 until the date the Company enters into a definitive agreement for the completion of a liquidity event.

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, 2022	1,695,500	$0.61
Granted	1,268,500	0.80
Exercised	(157,500)	(0.43)
Forfeited	(262,500)	(0.66)
Balance, December 31, 2022	2,544,000	$0.71
Granted	600,000	1.00
Forfeited	(70,000)	(0.62)
Balance, December 31, 2023	3,074,000	$0.77

In 2022, 1,050,000 Class C shares and 157,500 options on Class C shares were converted into common shares through a cashless exercise.

The fair market value of each Class C option granted in 2023 was estimated on the date of issue using the Black-Scholes pricing model and the following assumptions in the calculations:

Weighted average risk-free interest rate (%)	4.43
Expected life (years)	2.5
Estimated volatility of underlying common shares (%)	57
Share Price ($)	2.00
Estimated forfeiture rate (%)	nil

In addition, the Company assumed the probability of a liquidity event within the seven-year 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 $407,117 related to the Class C shares and options for the year ended December 31, 2023 ($57,646 in 2022) and capitalized $39,248 ($5,467 in 2022).

In June 2023, the Board of Directors extended the expiry of certain Class C shares and options to September 2026. The term extension is a modification under IFRS and requires an update to the share-based compensation expense. The incremental value of $1.1 million was determined and will be recognized over the estimated remaining expected term of 1.8 years for the Class C shares and options. The Company recognized $309,392 for the year ended December 31, 2023 which are included in the amounts described in the paragraph above.

The incremental value is the difference in value immediately before the modification (term extension) and immediately after the modification. The following assumptions were used in the calculations:

	Before Modification	After Modification
Weighted average risk-free interest rate (%)	4.83	4.55
Expected life (years)	0.5	1.8
Estimated volatility of underlying common shares (%)	60	60
Share Price ($)	1.99	1.99
Estimated forfeiture rate (%)	nil	nil

On January 1, 2024, the Company granted 825,000 options on Class C shares with an exercise price of $1.00 per share to officers and employees.

12. 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 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.

($)	December 31 2023	December 31 2022
Crude oil revenues	123,512	90,794
Natural gas revenues	12,855	19,805
Natural gas liquids revenues	7,051	5,734
Total	143,418	116,333

13. NET INCOME PER SHARE

	December 31 2023	December 31 2022
Net Income per share		
Basic	$0.26	$0.41
Diluted	$0.25	$0.39
Weighted average shares outstanding		
Basic	76,624	75,679
Diluted	80,738	79,555

14. INCOME TAXES

The following table reconciles the income tax expense computed by applying the Canadian statutory rate to the net income before income tax per the statement of net income and comprehensive income with the income tax expense recorded:

($ except statutory tax rate)	December 31 2023	December 31 2022
Net income before income tax	26,560	40,141
Canadian statutory income tax rate	23.00%	23.00%
Expected income tax at statutory rates	6,109	9,232
Add (deduct):		
Non-deductible share-based compensation and other	317	44
Provision for income tax	6,426	9,276
Current income tax	3,629	4,548
Deferred income tax	2,797	4,728

The components of deferred income tax at December 31, 2023 and 2022 are as follows:

($)	December 31 2023	December 31 2022
Deferred income tax liability:		
Capital assets carrying value in excess of tax value	(18,378)	(15,296)
	(18,378)	(15,296)
Deferred income tax asset:		
Decommissioning obligations	1,758	1,443
Financing costs	27	57
	1,785	1,500
Deferred income tax	(16,593)	(13,796)

The Company had approximately $108.8 million in available tax pools at December 31, 2023 ($83.4 million at December 31, 2022).

15. KEY MANAGEMENT PERSONNEL

The Company considers its directors and executives to be key management personnel.

The key management personnel compensation was comprised of the following:

($)	December 31 2023	December 31 2022
Salaries and other short-term benefits	2,370	2,635
Share-based compensation	1,194	144
Total	3,564	2,779

For the year ended December 31, 2023, the share-based compensation includes $1.0 million related to modification to certain terms on the Class B and Class C shares and certain options on Class B and Class C shares as described in Note 11.

16. SUPPLEMENTAL CASH FLOW INFORMATION

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

($)	December 31 2023	December 31 2022
Source / (use) of cash:		
Accounts receivable	(840)	(3,916)
Prepaid expenses and deposits	(345)	(111)
Accounts payable and accrued liabilities	8,443	10,939
Current income taxes	(5,035)	4,548
Change in non-cash working capital	2,224	11,460
Related to:		
Operating activities	(2,894)	6,030
Investing activities	5,118	5,430

17. COMMITMENTS

($)	Within 1 year	After 1 year but not more than 5 years	Total
Firm transportation – natural gas	232	598	830
Office lease	146	12	158
Total	378	610	988

Subsequent to December 31, 2023, the Company entered into an office lease agreement terminating on December 31, 2028 at a total estimated cost of $704,000.

18. 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, 2024. The agreement includes a funding limit of $14 million, which may be increased at the sole discretion of the party. At December 31, 2023, there is $3.8 million remaining on the funding limit.

Subsequent to December 31, 2023, the funding limit on the Royalty Acquisition Agreement was increased to $17 million and term extended to October 31, 2025.

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.

19. 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 December 31, 2023 and December 31, 2022, financial assets on the statement of financial position are comprised of cash, current income tax and trade and other receivables and the maximum credit risk associated with these financial instruments is the total carrying amount of these financial assets.

Cash equivalents include short-term deposits placed with financial institutions with strong investment grade ratings.

Accounts receivable for crude oil and natural gas sales are collected on or about the 25^{th} day of the month following production. At December 31, 2023, 89% of the accounts receivable amount relates to production revenue (97% at December 31, 2022).

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 $25 million revolving demand operating facility with a Canadian chartered bank which could be accessed if required.

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 December 31, 2023 and December 31, 2022 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 December 31, 2023 and 2022.

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 December 31, 2023 and 2022.

Corporate Information

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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

Steven Metzger
Vice President, Exploration

Lonny Tetley
Corporate Secretary

DIRECTORS

Clayton Woitas
Executive Chairman

Tyson Birchall

Jeff Lebbert

Margaret McKenzie

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