

NORTH 40

RESOURCES LTD.

April 5, 2023

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, 2022. Fourth quarter and full year highlights include:

- Annual average production rate of 4,230 boe/day (61% oil and liquids).
- Total annual operating revenue of \$116.3 mm.
- Average production for the fourth quarter 2022 of 5,174 boe/day (66 % oil and liquids), the Company's highest quarterly production to-date.
- Executed a \$67.6 million capital program in 2022 investing in 17 wells.
- Booked proved plus probable reserves of 12.5 mmboe, a 23% increase over same period 2021.
- Ended the year with total land holdings of ~224,578 acres.

North 40's 2022 capital program included the drilling of 17 wells. The first three quarters of 2022 included the drilling of 14 wells, with 3 wells drilled in Q4 2022. The 17 wells were distributed amongst Drumheller North - 6 wells, Drumheller - 7 wells, Wintering Hills - 1 well, Makepeace - 1 well, Matziwin West - 1 well and Princess - 1 well.

At Drumheller North, the battery construction has commenced, and we anticipate the completion of this project by the end of April 2023. When completed, the Drumheller North battery will allow North 40 to produce without restrictions.

At our Drumheller Banff pool, similar battery construction investments are in motion with the estimated project timeline in the fall of 2023. Part of the program includes the drilling of water disposal well. Development drilling will resume when the disposal facility is completed.

In Q1 2023 North 40 drilled 3 wells at Drumheller North to leverage off our battery construction investment. The 3 wells have been brought on production in late March and are still cleaning up. Early results are very positive. Our focus is on centralizing production, reducing equipping costs on future drills and minimizing solution gas issues. The remaining Q1 2023 North 40 wells were drilled at Matziwin South - 1 well, East Coulee - 1 well and Princess - 1 well. 2022 well results and Q1 2023 well results are in line with expectations.

The results from our Matziwin West, Princess and East Coulee drilling programs indicate natural gas productivity of 10-12 mmcf per day. These volumes will be brought on when natural gas prices recover.

Current North 40 production is approximately 5,750 boe/day with oil and liquids at 70% of production. Effective April 1st, 4,500 mcf per day of natural gas production was shut-in because of low commodity pricing. Production will be restarted with the recovery in natural gas prices. Remaining natural gas production is associated with oil production.

North 40's approved capital program for 2023 is \$62 mm and will consist of 14 wells in total. The Q2 – Q4 drilling will be allocated between oil development at Drumheller North, Drumheller Banff and oil exploration at Alderson. The capital program will be funded from cash flow.

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

NORTH 40 RESOURCES LTD.

Don W. Robson
President & CEO

NORTH 40

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MANAGEMENT'S DISCUSSION AND ANALYSIS

The following analysis was prepared as at April 5, 2023 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, 2022 and December 31, 2021, together with the accompanying notes, which have been prepared in accordance with International Financial Reporting 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-GAAP Measurements – Within Management's Discussion and Analysis, references are made to terms commonly used in the oil and gas industry. Management uses funds flow from operations to analyze operating performance. This term does not have any standardized meaning prescribed by GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. 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 before changes in non-cash working capital. 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.

(thousands, except per unit amounts and where indicated)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	2022	2021
FINANCIAL				
Petroleum and natural gas revenue	\$34,029	\$22,927	\$116,333	\$63,880
Funds flow from operations ⁽¹⁾	\$18,206	\$13,497	\$61,509	\$36,390
Per share – basic	\$0.24	\$0.18	\$0.81	\$0.48
Per share – diluted	\$0.23	\$0.17	\$0.77	\$0.47
Net income	\$8,186	\$6,190	\$30,865	\$15,301
Per share – basic	\$0.11	\$0.08	\$0.41	\$0.20
Per share – diluted	\$0.10	\$0.08	\$0.39	\$0.20
Field capital expenditures	\$17,638	\$6,506	\$67,625	\$35,885
Working capital surplus ⁽²⁾ at end of period	\$7,139	\$13,486	\$7,139	\$13,486
Common shares outstanding at end of period	76,624	75,250	76,624	75,250
OPERATING				
Sales volumes				
Oil and liquids (bbls/day)	3,391	2,554	2,560	2,104
Natural gas (mcf/day)	10,693	8,731	10,020	6,305
Total (boe/day) ⁽³⁾	5,174	4,009	4,230	3,154
% Oil and liquids	66	64	61	67
Commodity prices realized (before pipeline tariffs)				
Oil and liquids (\$/bbl)	96.05	83.71	106.16	74.04
Natural gas (\$/mcf)	5.42	5.11	5.75	4.22
Total (\$/boe)	74.17	64.46	77.88	57.83
Operating netback (\$/boe)	42.56	39.66	45.28	33.94
Funds from operations netback (\$/boe) ⁽¹⁾	38.25	36.60	39.84	31.61
Net wells drilled	3.0	-	17.0	14.0
Net acres of land at end of period	224,578	256,346	224,578	256,346

⁽¹⁾ Funds flow from operations does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar calculations by other entities. All references to funds flow from operations in this report are based on "cash provided by (used in) operating activities" before changes in non-cash working capital.

⁽²⁾ Working capital surplus does not have a standardized measure prescribed by IFRS and therefore may not be comparable to similar calculations by other entities. All references to working capital surplus in this report are based on Total Current Assets less Total Current Liabilities. Working capital surplus at December 31, 2022 includes \$19.1 million in cash (\$13.9 million at December 31, 2021).

⁽³⁾ Boe conversion is 6:1.

PRODUCTION

	Three Months Ended December 31		Year Ended December 31	
	2022	2021	2022	2021
Oil (bbls per day)	3,148	2,371	2,337	1,965
Liquids (bbls per day)	244	183	222	139
Natural gas (mcf per day)	10,693	8,731	10,020	6,305
BOE per day	5,174	4,009	4,230	3,154

Production in Q4 2022 and for the year ended December 31, 2022, averaged 5,174 boe per day (66% oil and liquids) and 4,230 boe per day (60% oil and liquids) respectively, compared to 4,009 boe per day (64% oil and liquids) and 3,154 boe per day (67% oil and liquids) in the comparable periods of 2021. Production increases are primarily due to the 2022 drilling programs partially offset by expected declines of existing production.

Ten wells were brought on production during the third quarter of 2022 and two natural gas wells were brought on in the fourth quarter which accounted for the majority of the production increase. Production increased 20% from 4,306 boe per day in Q3 2022 to 5,174 boe per day in Q4. Oil production accounted for more than 80% of the increase. Additional manpower in the field allowed for an increase in optimization work which also contributed to the increase.

Third party facility restrictions in the Drumheller area which began in late in Q1 2021 and continued throughout 2021 impacted production from 11 wells. These restrictions were resolved in Q1 2022 and the curtailed production is back online.

OPERATING NETBACKS⁽¹⁾

(\$ per BOE)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	2022	2021
Revenue ⁽²⁾	\$71.49	\$62.17	\$75.36	\$55.48
Royalties	(16.87)	(13.41)	(18.23)	(11.92)
Operating expenses	(10.02)	(7.03)	(9.94)	(7.52)
Transportation expenses	(2.04)	(2.07)	(1.91)	(2.10)
Operating netback	\$42.56	\$39.66	\$45.28	\$33.94

⁽¹⁾ Operating netback does not have a standardized measure prescribed by IFRS and therefore may not be comparable to similar calculations by other entities. All references to operating netback in this report are based on revenue less royalties, operating expenses and transportations expensed divided by production volume.

⁽²⁾ Includes pipeline tariff amount of \$2.68 and \$2.52 per boe for the three months and year ended December 31, 2022 respectively and \$2.30 per boe and \$2.34 per boe in the comparable periods of 2021.

COMMODITY PRICES

(\$ per bbl)	Three Months Ended December 31		Year Ended December 31	
	2022	2021	2022	2021
WTI (US\$/bbl)	\$82.65	\$77.19	\$94.23	\$67.92
MSW benchmark price ⁽¹⁾	\$110.06	\$93.15	\$120.07	\$80.08
WCS benchmark price ⁽²⁾	\$77.42	\$78.72	\$98.51	\$68.74
Realized crude oil price	\$98.44	\$85.57	\$109.52	\$75.58

⁽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 2022 was \$98.44 per barrel which is 15% higher than the Q4 2021 price of \$85.57 per barrel. The Company's realized crude oil price (before pipeline tariffs) in 2022 averaged \$109.52 per barrel, 45% higher than the 2021 average of \$75.58 per barrel. The increase is primarily due to the 39% increase in WTI benchmark prices from an average of \$67.92 per barrel in 2021 to \$94.23 per barrel in 2022 along with a weaker Canadian dollar.

WTI benchmark prices were strong in 2022 however softened in the second half of the year as global recessionary fears weighed on the global demand outlook given high inflation, tightening monetary policies by central banks and rising interest rates. Differentials for medium and heavy crude oil also widened on refinery outages, incremental supply of those grades from OPEC+ countries and releases from the United States Strategic Petroleum Reserve.

(\$ per mcf)	Three Months Ended		Year Ended	
	December 31		December 31	
	2022	2021	2022	2021
AECO Daily (5A) index	\$5.12	\$4.65	\$5.32	\$3.62
Realized natural gas price	\$5.42	\$5.11	\$5.75	\$4.22

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 increased 6% to \$5.42 per mcf in Q4 2022 from \$5.11 per mcf in Q4 2021. Realized natural gas price of \$5.75 per mcf in 2022 increased 36% from the 2021 average of \$4.22.

AECO natural gas prices were negatively impacted by significant seasonal pipeline system maintenance in the third quarter of 2022 which continued into the early part of Q4.

AECO natural gas prices have moved higher in 2022 with increases in domestic and global demand which have led to significantly lower-than-average storage in Western Canada. Global natural gas and LNG prices have increased dramatically, especially in Europe, with Russia's invasion of Ukraine disrupting natural gas distribution.

REVENUE

(\$ thousands)	Three Months Ended		Year Ended	
	December 31		December 31	
	2022	2021	2022	2021
Oil and liquids	\$29,037	\$19,072	\$96,528	\$54,821
Natural gas	4,992	3,855	19,805	9,059
Petroleum and natural gas revenue	\$34,029	\$22,927	\$116,333	\$63,880
% Oil and liquids	85	83	83	86

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

Revenue in Q4 2022 increased 48% to \$34.0 million from \$22.9 million in Q4 2021. About 64% of the revenue increase is as a result of higher production volumes with the remaining increase due to higher commodity prices. The increase in crude oil production volume was the largest contributor to the increase.

Revenue for the year ended December 31, 2022 increased by 82% from \$63.9 million in 2021 to \$116.3 million on increased commodity prices and on higher production volumes. Approximately 67% of the revenue increase is due to higher commodity prices and 33% due to higher production volumes.

Oil and liquids revenue represented 85% of total revenue in Q4 2022 and increased 52%, from \$19.1 million in Q4 2021 to \$29.0 million in Q4 2022. Crude oil realizations were 15% higher and oil production volumes were 33% higher in Q4 2022 compared to the same quarter last year.

Natural gas revenue increased 29% in Q4 2022 from \$3.9 million in Q4 2021 to \$5.0 million. The increase is due to a 6% increase in price realizations and a 22% increase in production volume in Q4 2022 compared to the same period in 2021.

Oil pipeline tariffs of \$0.9 million and \$2.6 million are included in revenue for the fourth quarter and the year ended December 31, 2022 respectively. This compares to \$0.6 million and \$2.0 million in the same periods of 2021. The custody transfer to the purchaser is at the point the oil is offloaded at the terminal. Gas pipeline tariffs of \$0.3 million and \$1.9 million are also included in revenue for the three months and year ended December 31, 2022, respectively. This compares to \$0.3 million and \$0.7 million in the same periods of 2021. 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		Year Ended	
	December 31		December 31	
	2022	2021	2022	2021
Royalties	\$8,029	\$4,946	\$28,144	\$13,728
Per BOE	\$16.87	\$13.41	\$18.23	\$11.92
% of Revenue before pipeline tariffs	23%	21%	23%	21%

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 increased to \$16.87 per boe and \$8.0 million in the fourth quarter of 2022 compared to \$13.41 per boe and \$4.9 million in the fourth quarter of 2021 commensurate with higher realized commodity prices and higher production volume.

For the year ended December 31, 2022, royalties averaged \$18.23 per boe and \$28.1 million compared to \$11.92 per boe and \$13.7 million in the same period of 2021 due to the same factors contributing to the fourth quarter increase.

Royalties as a percentage of revenue were 23% and 21% in the fourth quarters of 2022 and 2021 respectively. Royalties as a percentage of revenue increased to 23% for the year ended December 31, 2022 compared to 21% for the same period in 2021. The percentage of revenue increase is mainly due to the sliding scale nature of certain royalties which increases the royalty percentage paid when commodity prices are higher.

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

<i>(thousands, except per unit amounts)</i>	Three Months Ended December 31		Year Ended December 31	
	2022	2021	2022	2021
Operating expenses	\$4,771	\$2,591	\$15,340	\$8,653
Per BOE	\$10.02	\$7.03	\$9.94	\$7.52
Transportation expenses	\$973	\$764	\$2,949	\$2,425
Per BOE	\$2.04	\$2.07	\$1.91	\$2.10

Operating expenses averaged \$10.02 (\$4.8 million) and \$9.94 per boe (\$15.3 million) for the fourth quarter and year ended December 31, 2022, respectively compared to \$7.03 (\$2.6 million) and \$7.52 per boe (\$8.7 million) for the same periods in 2021. Main contributors to the increase were well servicing costs and the impact of inflationary pressures most prevalent with fuel charges and labor services.

Transportation costs, which are clean oil trucking expenses, averaged \$2.04 (\$1.0 million) and \$1.91 (\$2.9 million) per boe in the fourth quarter and the year ended December 31, 2022, respectively compared to \$2.07 (\$0.8 million) and \$2.10 (\$2.4 million) per boe in the same periods of 2021. The cost is incurred on oil production only and therefore increases in the natural gas production weighting will decrease the per boe cost. Natural gas production represented 38% of total production in 2022 and 33% in 2021. Fuel surcharges increased clean oil trucking costs in 2022.

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. In 2022, increased clean oil trucking costs were incurred to transport crude oil further distances to terminals where a higher netback was achieved.

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. The well in dispute was drilled and brought on production in Q3 2021.

GENERAL AND ADMINISTRATIVE

<i>(thousands, except per unit amounts)</i>	Three Months Ended December 31		Year Ended December 31	
	2022	2021	2022	2021
Gross G&A	\$1,392	\$1,151	\$4,021	\$2,779
Capitalized G&A	(136)	(24)	(264)	(93)
Net G&A	\$1,256	\$1,127	\$3,757	\$2,686
Per BOE	\$2.64	\$3.06	\$2.43	\$2.33

Net general and administrative ("G&A") expenses were \$1.3 million and \$3.8 million for the fourth quarter and the year ended December 31, 2022, respectively compared to \$1.1 million and \$2.7 million in the comparable periods of 2021. The increase in 2022 from 2021 are largely due to payments related to the departure of the Company's former President & CEO. There were also higher costs for professional and contractor services as well as insurance premiums in 2022 compared to 2021. On a boe basis, net G&A was \$2.64 and \$2.43 per boe in Q4 and for the year ended December 31, 2022, respectively compared to \$3.06 and \$2.33 per boe in same periods of 2021.

The most significant costs in 2022 can be attributed to employee salaries, benefits and annual bonus, payments related to the departure of the Company's former President & CEO as well as professional and contractor services.

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

SHARE BASED COMPENSATION

<i>(thousands, except per unit amounts)</i>	Three Months Ended December 31		Year Ended December 31	
	2022	2021	2022	2021
Share based compensation	\$64	\$60	\$186	\$240
Capitalized share-based compensation	(4)	(2)	(14)	(8)
	\$60	\$58	\$171	\$232
Per BOE	\$0.14	\$0.16	\$0.11	\$0.20

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.

The decrease in share-based compensation expense in 2022 compared to 2021 is mostly due to prior years grants of Class B and Class C shares being fully expensed.

Detailed information regarding the Class B and Class C shares and options have been disclosed in Note 10 of the financial statements.

DEPLETION AND DEPRECIATION

<i>(thousands, except per unit amounts)</i>	Three Months Ended December 31		Year Ended December 31	
	2022	2021	2022	2021
Depletion and depreciation	\$7,606	\$5,026	\$25,045	\$16,108
Per BOE	\$15.98	\$13.63	\$16.22	\$13.99

The Company recognized depletion and depreciation expense ("D&D") of \$7.6 million (\$15.98 per boe) and \$25.0 million (\$16.22 per boe) for the quarter and the year ended December 31, 2022, respectively compared to \$5.0 million (\$13.63 per boe) and \$16.1 million (\$13.99 per BOE) in the same periods of 2021. Higher estimates for future development costs, due to additional capital and inflation, are the major contributor to the increase in the per unit D&D expense in 2022. The D&D expense was based on an internal evaluation of proved and probable reserves and an internal estimate of future development costs.

The D&D expense recognized was comprised primarily of depletion expenses with minor amounts relating to depreciation of office assets and a field vehicle. In 2022, included in depletion and depreciation, is an impairment charge of \$0.2 million related to equipment failure at a Drumheller North oil battery. In addition, other income of \$0.2 million was recognized in Q2 2022 for estimated expected insurance proceeds for the damaged equipment.

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 \$0.2 million (\$0.47 per boe) in Q4 2022 and \$0.5 million (\$0.34 per boe) for the 2022 year predominantly due to undeveloped land expiries. Exploration expense for Q4 2021 and for the 2021 year was \$2,000.

Property and Equipment

At December 31, 2022 and 2021, there were no indicators of impairment identified and an impairment test was not performed.

FINANCE EXPENSE

<i>(thousands)</i>	Three Months Ended December 31		Year Ended December 31	
	2022	2021	2022	2021
Accretion of decommissioning obligations	\$51	25	\$177	87
Banking fees	47	8	98	52
Interest on leased liabilities	6	8	28	38
Total	\$104	\$41	\$303	\$177
Per BOE	\$0.22	\$0.11	\$0.20	\$0.15

Finance expense relates to accretion on decommissioning obligations, banking fees and the interest on lease liabilities. Banking fees include standby fees and fees associated with the annual bank facility review. The increase in banking fees in 2022 relates to the increase in the bank credit facility to \$25 million from \$8.5 million. Accretion of decommissioning obligations and interest on leased liabilities are non-cash charges.

INCOME TAXES

North 40 recognized current income tax expense of \$0.4 million in Q4 2022 and \$4.5 million for the year ended December 31, 2022. The Company did not recognize current income taxes in 2021. North 40 will owe cash taxes related to its current income tax expense for the full year ended December 31, 2022, which will be paid in the first quarter of 2023.

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, 2022, a deferred income tax expense of \$2.1 million and \$4.7 million, respectively, was recognized compared to a deferred income tax expense of \$2.2 million and \$4.7 million for the comparable periods in 2021.

The following tax pool balances are estimated at December 31, 2022 and 2021:

<i>(thousands)</i>	Maximum Annual Deduction	2022	2021
Canadian oil and gas property expense (COGPE)	10%	\$15,487	\$13,897
Canadian development expense (CDE)	30%	40,551	30,132
Canadian exploration expense (CEE)	100%	-	-
Undepreciated capital cost (UCC)	25%	27,373	15,003
Non-capital losses (NCL)	100%	-	2,657
		\$83,411	\$61,689

NET INCOME AND COMPREHENSIVE INCOME

<i>(thousands)</i>	Three Months Ended December 31		Year Ended December 31	
	2022	2021	2022	2021
Net income and comprehensive income	\$8,186	\$6,190	\$30,865	\$15,301
Per share – basic	\$0.11	\$0.08	\$0.41	\$0.20
– diluted	\$0.10	\$0.08	\$0.39	\$0.20

North 40 recognized 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 three months and year ended December 31, 2022, respectively and net income and comprehensive income of \$6.2 million (\$0.08 per basic and diluted share) and \$15.3 million (\$0.20 per basic and diluted share) for the comparable periods in 2021.

The increase in net income for the three months and year ended December 31, 2022, as compared to the same periods in 2021 is primarily due to an increase in revenue partially offset by increases in royalties, operating and transportation costs, general and administrative costs, depletion and depreciation, exploration expense, settlement expense and higher current and deferred income tax expense.

CAPITAL EXPENDITURES

Capital expenditures by type and by area for the three months and year ended December 31, 2022 and 2021 were as follows:

<i>(thousands)</i>	Three Months Ended December 31		Year Ended December 31	
	2022	2021	2022	2021
Land and lease rentals ⁽¹⁾	\$1,363	\$1,294	\$4,151	\$3,315
Seismic and geological	1,940	1,176	2,348	1,184
Drilling and completion	5,065	439	35,314	21,721
Equipping and tie-ins	9,270	3,597	25,812	9,665
Total field capital expenditures	\$17,638	\$6,506	\$67,625	\$35,885

(1) Net of land fund reimbursements

(2) Capitalized G&A of \$141,000 in Q4 2022 (\$26,000 in Q4 2021) and \$279,000 in 2022 (\$103,000 in 2021) have been excluded from this table.

(3) Office expenditures of \$4,000 have been excluded from this table.

<i>(thousands)</i>	Three Months Ended		Year Ended	
	December 31		December 31	
	2022	2021	2022	2021
Drumheller	\$9,740	\$4,974	\$52,703	\$30,322
Matziwin	3,452	434	6,396	2,474
Princess	2,949	1,087	4,543	3,055
Alderson	1,244	-	1,254	-
Other	253	11	2,729	34
Total field capital expenditures	\$17,638	\$6,506	\$67,625	\$35,885

Wells drilled by property were as follows:

	Three Months Ended		Year Ended	
	December 31		December 31	
	2022	2021	2022	2021
Drumheller ⁽¹⁾	1	-	7	6
Drumheller North ⁽¹⁾	-	-	6	3
Wintering Hills ⁽¹⁾	-	-	1	3
Matziwin West ⁽²⁾	1	-	1	1
Makepeace	-	-	1	-
Princess	1	-	1	1
Total	3	-	17	14

⁽¹⁾ Included in Drumheller area

⁽²⁾ Included in 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 Alderson,
- drilling and completion of three wells drilled in the quarter. 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 the fourth quarter of 2021 were \$6.5 million which includes a freehold lease extension at Wintering Hills, a 3S seismic shoot at Princess, completion, equipping and tie-in operations on several wells drilled in Q3 2021, and equipment purchases for the Q1 2022 drilling program.

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 Alderson and Drumheller North 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 Drumheller North, 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.

The Company has experienced higher-than-forecast inflationary cost pressures most prevalent with fuel surcharges, wages and supply chain issues. Compared to 2021, inflationary cost pressures have likely added \$0.6 million per well in 2022.

Capital expenditures in 2021 were \$35.9 million, the majority of which were expended on the Company's 14 well drilling program. Freehold lease extensions were also completed in Drumheller North and Wintering Hills and a 3D seismic shoot was completed at Princess.

North 40's land holdings per area at December 31, 2022 and 2021 were as follows:

<i>(acres)</i>	December 31, 2022	December 31 2021
Drumheller	106,004	119,016
Matziwin	78,579	100,029
Princess	18,700	17,908
Alderson	10,444	9,811
Makepeace	7,679	-
Other	3,172	9,582
Total	224,578	256,346

The land holdings consist of 52% crown and 48% freehold leases at December 31, 2022. Working interest in North 40's land holdings is 100 percent.

The decrease in land holdings at December 31, 2022, compared to the same time last year is due to undeveloped crown land expiries.

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 \$6.3 million at December 31, 2022. (\$6.5 million at December 31, 2021).

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 3.29% (1.52% at December 31, 2021) and an inflation rate of 2.20% (2.20% at December 31, 2021) were used to calculate the best estimate of the decommissioning obligation. The decrease in the decommissioning obligation at December 31, 2022, compared to December 31, 2021, is due to the increase in the risk-free rate partially offset by new liabilities recognized for new wells drilled.

FUNDS FLOW FROM OPERATIONS

As funds flow from operations is a non-GAAP measure, the following table reconciles the differences between the accounting measures of "cash flow from operating activities" and "funds flow from operations" for the following periods ended:

<i>(millions)</i>	Three Months Ended		Year Ended	
	December 31		December 31	
	2022	2021	2022	2021
Cash provided by operating activities	\$22.6	\$15.2	\$67.5	\$35.4
Net change in non-cash working capital	(4.4)	-	(6.0)	-
Funds flow from operations	\$18.2	\$13.5	\$61.5	\$36.4

LIQUIDITY AND CAPITAL RESOURCES

At December 31, 2022, the Company had no drawn debt and working capital of \$7.1 million comprised of \$19.1 million in cash and a working capital deficit of \$12.0 million. All activities to date have been funded with proceeds from the Company's initial equity financing, cash flow from operations, land fund reimbursements and interest income on cash balances.

The Company has 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 \$0.5 million at December 31, 2022.

The facility includes a financial covenant that requires the working capital with adjustments 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, 2022. 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, 2022, is 16.1. 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. A review was completed November 30, 2022, with no changes to the amount and terms of the credit facility. The next review date has been set for May 31, 2023.

The Company has 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 \$8 million, which may be increased at the sole discretion of the party. At December 31, 2022, there is \$4.4 million remaining on the funding limit.

Subsequent to December 31, 2022, the funding limit on the Royalty Acquisition Agreement was increased to \$14 million.

RESERVE INFORMATION

North 40's reserves have been internally evaluated by the Company's engineers as at December 31, 2022 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, 2022:

(Company Interest)	Oil and Liquids (Mbbbls)	Natural Gas (MMcf)	Oil Equivalent (Mboe)
Proved developed producing	2,728	10,228	4,432
Proved developed non-producing	6	791	138
Proved undeveloped	2,746	4,884	3,559
Total proved	5,479	15,903	8,129
Probable	3,041	8,158	4,400
Total proved plus probable	8,520	24,061	12,530

The following table summarizes changes in reserves during 2022:

(Mboe)	Proved Producing	Total Proved	Total Probable	Total Proved & Probable
December 31, 2021	3,456	7,174	3,010	10,184
Production – 2022	(1,544)	(1,544)	-	(1,544)
Additions	2,236	2,236	1,513	3,749
Net acquisitions	-	-	-	-
Technical revisions	284	263	(123)	140
December 31, 2022	4,432	8,129	4,400	12,530

NET PRESENT VALUES OF FUTURE NET REVENUE (BEFORE INCOME TAXES)

Net Reserve Value (\$ Million)	0%	5%	10%	15%	20%
Proved developed producing	126	115	105	96	90
Proved developed non-producing	-	-	-	-	-
Proved undeveloped	99	76	60	49	41
Total proved	225	191	165	145	131
Probable	141	103	80	65	53
Total proved plus probable	366	294	245	210	184

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 than 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, 2023 price forecast of McDaniels & Associates Consultants Ltd. and North 40’s estimates.

Summary of Pricing Assumptions
Effective December 31, 2022
Forecast Price and Costs

Forecast Year	Oil			Gas		
	WTI Cushing Oklahoma (\$US)	Edmonton Light (\$C)	N40 Oil Price (\$C)	Henry Hub (\$US)	AECO Spot (\$C)	N40 Gas Price (\$C)
	(\$/bbl)			(\$/mmbtu)		
2023	80.00	102.67	90.00	4.50	4.00	4.45
2024	76.50	96.67	86.21	4.50	4.08	4.54
2025	75.43	95.13	85.45	4.42	4.16	4.61
2026	74.28	93.50	84.21	4.51	4.24	4.72
2027	75.77	95.37	85.97	4.60	4.33	4.82
2028	77.29	97.27	87.70	4.69	4.42	4.93
2029	78.83	99.22	89.44	4.79	4.50	5.04
2030	80.41	101.20	91.22	4.88	4.59	5.16
2031	82.02	103.23	93.05	4.98	4.69	5.27

Note: Inflation rate assumption is 2% per annum.

CAPITAL EFFICIENCIES

	2022
Finding, development, and acquisition costs ⁽¹⁾	
Total proved (\$ per boe)	\$30.89
Proved plus probable reserves (\$ per boe)	\$23.71
Recycle Ratio ⁽²⁾ (times)	1.9

⁽¹⁾ Includes future development costs of \$56.8 million on a proved basis and \$85.0 million on a proved plus probable basis.

⁽²⁾ Based on 2022 operating netbacks and F&D costs for proved plus probable reserves.

SELECTED QUARTERLY INFORMATION

Three Months Ended	Dec 31	Sept 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31
	2022	2022	2022	2022	2021	2021	2021	2021
FINANCIAL								
Petroleum and natural gas revenue	\$34,029	\$28,699	\$30,675	\$22,930	\$22,927	\$18,861	\$11,858	\$10,234
Funds flow from operations ⁽¹⁾	\$18,206	\$15,011	\$16,467	\$11,826	\$13,497	\$10,984	\$6,381	\$5,528
Per share – basic	\$0.24	\$0.20	\$0.22	\$0.16	\$0.18	\$0.15	\$0.08	\$0.07
Per share – diluted	\$0.23	\$0.18	\$0.20	\$0.15	\$0.17	\$0.14	\$0.08	\$0.07
Net income (loss)	\$8,186	\$6,291	\$10,222	\$6,166	\$6,190	\$5,032	\$2,428	\$1,651
Per share – basic	\$0.11	\$0.08	\$0.14	\$0.08	\$0.08	\$0.07	\$0.03	\$0.02
Per share – diluted	\$0.10	\$0.08	\$0.13	\$0.08	\$0.08	\$0.07	\$0.03	\$0.02
Capital expenditures	\$17,638	\$20,342	\$18,809	\$10,836	\$6,506	\$13,962	\$7,695	\$7,722
Working capital surplus at end of period	\$7,139	\$6,737	\$12,141	\$14,401	\$13,486	\$6,545	\$9,575	\$10,943
Common shares outstanding end of period	76,624	76,624	75,340	75,250	75,250	75,250	75,250	75,250
OPERATING								
Sales volumes								
Oil and liquids (bbls/day)	3,391	2,656	2,155	2,020	2,554	2,454	1,728	1,664
Natural gas (mcf/day)	10,693	9,897	9,363	10,122	8,731	6,460	4,481	5,512
Total (boe/day) ⁽²⁾	5,174	4,306	3,715	3,707	4,009	3,531	2,475	2,583
% Oil and liquids	66	62	58	54	64	70	70	64
Commodity prices realized (before pipeline tariffs)								
Oil and liquids (\$/bbl)	96.05	104.34	126.40	104.13	83.71	76.21	69.92	60.00
Natural gas (\$/mcf)	5.42	4.59	7.91	5.26	5.11	4.07	3.49	3.57
Total (\$/boe)	74.17	74.91	93.24	71.10	64.46	60.42	55.14	46.27
Operating netback (\$/boe)	42.56	41.97	56.99	41.20	39.66	35.26	30.55	26.28
Funds from operations netback (\$/boe) ⁽¹⁾	38.25	37.89	48.71	35.45	36.60	33.81	28.33	23.78
Net wells drilled	3.0	5.0	5.0	4.0	-	7.0	4.0	3.0
Net acres of land at end of period	224,578	221,828	221,777	235,266	256,346	254,682	254,123	253,324

⁽¹⁾ Funds flow from operations does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar calculations by other entities. All references to funds flow from operations in this report are based on “cash provided by (used in) operating activities” before changes in non-cash working capital.

⁽²⁾ Boe conversion is 6:1.

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

	2022	2021	2020	2019	2018	2017
FINANCIAL						
Petroleum and natural gas revenue	\$116,333	\$63,880	\$30,114	\$56,711	\$22,180	\$3,842
Funds flow from operations ⁽¹⁾	\$61,509	\$36,390	\$14,463	\$33,845	\$11,023	\$1,267
Per share – basic	\$0.81	\$0.48	\$0.19	\$0.45	\$0.19	\$0.03
Per share – diluted	\$0.77	\$0.47	\$0.19	\$0.42	\$0.18	\$0.03
Net income (loss)	\$30,865	\$15,301	\$(910)	\$11,236	\$2,013	\$(550)
Per share – basic	\$0.41	\$0.20	\$(0.01)	\$0.15	\$0.03	\$(0.01)
Per share – diluted	\$0.39	\$0.20	\$(0.01)	\$0.14	\$0.03	\$(0.01)
Capital expenditures	\$67,625	\$35,888	\$16,663	\$40,072	\$42,324	\$21,277
Working capital surplus at end of period	\$7,139	\$13,486	\$13,186	\$15,518	\$21,962	\$27,950
Common shares outstanding end of period	76,624	75,250	75,250	75,250	75,250	50,020
OPERATING						
Sales volumes						
Oil and liquids (bbls/day)	2,560	2,104	1,749	2,486	1,132	186
Natural gas (mcf/day)	10,020	6,305	4,955	6,988	2,056	121
Total (boe/day) ⁽²⁾	4,230	3,154	2,575	3,651	1,475	206
% Oil and liquids	61	67	68	68	77	90
Commodity prices realized (before pipeline tariffs)						
Oil and liquids (\$/bbl)	106.16	74.04	43.64	61.03	54.96	59.44
Natural gas (\$/mcf)	5.75	4.22	2.59	1.88	1.54	1.91
Total (\$/boe)	77.88	57.83	34.63	45.17	44.34	54.74
Operating netback (\$/boe) (before hedging settlements)	45.28	33.94	18.22	27.03	24.81	34.22
Hedging Settlements	-	-	(0.98)	-	-	-
Operating netback (\$/boe) (after hedging settlements)	45.28	33.94	17.24	27.03	24.81	34.22
Funds from operations netback (\$/boe) ⁽¹⁾	39.84	31.61	15.35	25.44	20.51	16.87
Net wells drilled	17.0	14.0	6.0	14.0	16.0	7.0
Net acres of land at end of period	224,578	256,346	255,254	283,195	229,455	99,773

⁽³⁾ Funds flow from operations does not have a standardized meaning prescribed by IFRS and therefore may not be comparable to similar calculations by other entities. All references to funds flow from operations in this report are based on “cash provided by (used in) operating activities” before changes in non-cash working capital.

⁽⁴⁾ Boe conversion is 6:1.

NORTH 40

RESOURCES LTD.

**Financial Statements
For the year ended December 31, 2022**



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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, 2022
- 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 significant accounting policies

(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, 2022, and its financial performance and its cash flows for the year then ended in accordance with International Financial Reporting Standards (IFRS) 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 International Financial Reporting Standards (IFRS) 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 represents 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 5, 2023

North 40 Resources Ltd.
Statements of Financial Position

As at	December 31 2022	December 31 2021
<i>(\$ thousands)</i>		
ASSETS		
Current Assets		
Cash and cash equivalents	19,066	13,952
Accounts receivable	10,853	6,937
Prepays and deposits	691	580
Total Current Assets	30,610	21,470
Exploration and evaluation assets (Note 4)	23,318	21,422
Property and equipment (Note 5)	126,595	86,543
Total Assets	180,523	129,435
LIABILITIES AND SHAREHOLDERS' EQUITY		
Current Liabilities		
Accounts payable and accrued liabilities	18,923	7,984
Current income taxes (Note 13)	4,548	-
Total Current Liabilities	23,471	7,984
Lease liabilities (Note 9)	248	366
Decommissioning obligations (Note 8)	6,273	6,486
Deferred income taxes (Note 13)	13,796	9,068
Total Liabilities	43,788	23,904
Shareholders' Equity		
Share capital (Note 10)	76,245	75,416
Contributed surplus	3,342	3,832
Retained earnings	57,148	26,283
Total Shareholders' Equity	136,735	105,531
Total Liabilities and Shareholders' Equity	180,523	129,435

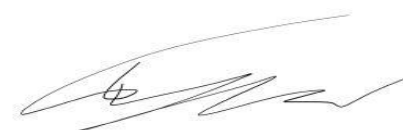
Subsequent Event (Note 17)

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

2022 **2021**

(\$ thousands except per share amounts)

	2022	2021
Revenue		
Petroleum and natural gas revenue (Note 11)	116,333	63,880
Less: Royalties	28,144	13,728
	88,189	50,152
Interest income	376	92
Other income (Note 5)	166	-
	88,731	50,244
Expenses		
Operating	15,340	8,653
Transportation	2,949	2,425
General and administrative	3,757	2,686
Share based compensation (Note 10)	171	232
Depletion and depreciation (Note 5)	25,045	16,108
Exploration expense (Note 4)	523	2
Settlement expense (Note 6)	502	-
Finance expense	303	177
Total expenses	48,590	30,283
Income before taxes	40,141	19,961
Current income tax expense (Note 13)	4,548	-
Deferred income tax expense (Note 13)	4,728	4,660
Net Income and Comprehensive Income	30,865	15,301
Net Income per share (Note 12)		
Basic	\$0.41	\$0.20
Diluted	\$0.39	\$0.20

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
<i>(\$ thousands)</i>				
Balance as at December 31, 2020	75,416	3,592	10,982	89,990
Net income	-	-	15,301	15,301
Share based compensation (Note 10)	-	240	-	240
Balance as at December 31, 2021	75,416	3,832	26,283	105,531
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 10)	-	186	-	186
Balance as at December 31, 2022	76,245	3,342	57,148	136,735

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

North 40 Resources Ltd.

Statements of Cash Flow

Years ended December 31

	2022	2021
<i>(\$ thousands)</i>		
Cash provided by (used in):		
Operating activities		
Net income for the year	30,865	15,301
Adjusted for:		
Depletion and depreciation (Note 5)	25,045	16,108
Exploration expense (Note 4)	523	2
Accretion expense (Note 8)	177	87
Share based compensation (Note 10)	171	232
Deferred income tax expense (Note 13)	4,728	4,660
	61,509	36,390
Net change in non-cash working capital (Note 15)	6,030	(994)
	67,539	35,396
Financing activities		
Issue of share capital (Note 10)	153	-
Repayment of lease liabilities (Note 9)	(117)	(108)
	36	(108)
Investing activities		
Exploration and evaluation expenditures (Note 4)	(8,905)	(8,269)
Property and equipment expenditures (Note 5)	(58,986)	(27,715)
Net change in non-cash working capital (Note 15)	5,430	(177)
	(62,461)	(36,161)
Change in cash and cash equivalents	5,114	(873)
Cash and cash equivalents, beginning of year	13,952	14,825
Cash and cash equivalents, end of year	19,066	13,952

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

North 40 Resources Ltd.

Notes to the Financial Statements

December 31, 2022 and 2021 *(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 International Financial Reporting Standards (“IFRS”) 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 5, 2023.

(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 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.

Estimates and judgements made by management in the preparation of these condensed interim financial statements are subject to a higher degree of measurement uncertainty during this volatile period.

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

(i) Cash generating units

Cash generating units (“CGUs”) are defined as the lowest grouping of integrated assets that generate identifiable cash inflows that are largely independent of the cash flows of other assets or group of assets. The classification of assets into CGUs requires significant judgement and interpretations with respect to the integration between assets, the existence of active markets, external users, shared infrastructure, and the way in which management monitors the Company’s operations.

The Company has determined that at December 31, 2022 it has one CGU.

(ii) 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.

(iii) 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.

(iv) 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.

The Company recognizes the net future tax benefit related to a deferred tax asset to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred tax assets requires the Company to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecasted cash flows from operations and the application of existing tax laws in each jurisdiction. To the extent that future cash flows and taxable income differ significantly from estimates, the ability of the Company to realize net deferred tax assets recorded at the reporting date could be impacted. Additionally, future changes in tax laws in the jurisdictions in which the Company operates could limit the ability of the Company to obtain tax deductions in future periods.

(v) 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.

(vi) 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.

(vii) 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.

(viii) Revenue and Expenditures

Revenues and expenditures, including expenditures on exploration and evaluation assets and property and equipment, are subject to estimation as at a reporting date, but for which actual revenues and expenditures have not yet been received.

3. SIGNIFICANT ACCOUNTING POLICIES

(a) Cash and Cash Equivalents

Cash and cash equivalents include cash on hand, deposits held with banks and other short-term highly liquid investments with maturities of three months or less from inception. Cash and cash equivalents are categorized as financial assets measured at amortized cost.

(b) 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 combined 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.

(c) 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.

An item of property and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on derecognition of the asset (calculated as the difference between the net disposal proceeds and the carrying amount of the item) is included in net income in the period in which the item is derecognized.

direct costs. Depreciation is recognized on the right-of-use asset over the lease term. Interest expense is recognized on the lease liabilities using the effective interest rate method and payments are applied against the lease liability.

Management has made judgments, estimates and assumptions related to the application of IFRS 16 which include:

- The incremental borrowing rates are based on judgments including economic environment, term, currency, and the underlying risk inherent to the asset. The carrying balance of the right-of-use asset, lease liabilities, and the resulting interest and depreciation expense may differ due to changes in the market conditions and lease term.
- Lease terms are based on assumptions regarding extension terms that allow for operational flexibility and future market conditions.

(e) 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.

(f) Financial Instruments

Recognition and Measurement

Trade receivables or debt securities 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.

Financial Instrument	Measurement Category	
	Classification	Subsequent Measurement
Cash and cash equivalents	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

Impairment of Financial Assets

Loss allowances for trade receivables are measured at an amount equal to lifetime expected credit losses ("ECLs"). ECLs are a probability weighted average estimate of credit losses. Credit losses are measured as the present value difference between the cash flows due to the Company in accordance with the contract and the cash flows the Company expects to receive. As at December 31, 2022, the majority of the Company's receivables were from oil and natural gas marketers which are normally collected on the 25th day of the month following production.

(g) 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.

(h) Share Capital

Common shares are classified as equity. Incremental costs directly attributable to the issuance of shares are recognized as a deduction from equity.

(i) 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.

(j) Government Grants

Government grants are recognized when there is reasonable assurance that the grant will be received and all conditions associated with the grant have been met. Grants related to income are presented as part of profit or loss, either separately or under a general heading; alternatively, they are deducted in reporting the related expense. The Company has elected to deduct grants received from the related expense.

(k) 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.

(l) 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 2022	December 31 2021
Balance, beginning of period	21,422	20,514
Additions	8,905	8,268
Exploration expense	(523)	(2)
Transferred to property and equipment	(6,486)	(7,358)
Balance, end of period	23,318	21,422

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proved and/or probable reserves. Costs primarily relate to undeveloped land.

For the year ended December 31, 2022, the Company recognized exploration expenses of \$0.5 million (\$2,000 in 2021) primarily related to undeveloped land expiries.

5. PROPERTY AND EQUIPMENT

(\$)	December 31 2022	December 31 2021
Property and equipment, at cost	207,099	142,002
Accumulated depletion and depreciation	(80,504)	(55,459)
Net book value, end of period	126,595	86,543

Reconciliations of movements during the period:

Cost, beginning of period	142,002	104,825
Accumulated depletion and depreciation, beginning of period	(55,459)	(39,352)
Net book value, beginning of period	86,543	65,473
Additions	59,001	27,723
Right-of-use asset	-	127
Transferred from exploration and evaluation assets	6,486	7,358
Changes in decommissioning obligations (Note 8)	(390)	1,970
Depletion and depreciation	(25,045)	(16,108)
Net book value, end of period	126,595	86,543

Included in the calculation of depletion was an estimate for future development costs of \$85.0 million at December 31, 2022 (\$60.5 million at December 31, 2021). An estimated future salvage value of \$5.5 million was excluded from the calculation of depletion at December 31, 2022 (\$3.8 million at December 31, 2021).

Included in the December 31, 2022 property and equipment balance is the right-of-use asset of \$0.2 million (\$0.3 million at December 31, 2021).

Included in additions is capitalized general and administrative expenses of \$0.3 million (\$0.1 million in 2021).

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, 2022, and December 31, 2021, 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. The well in dispute was drilled and brought on production in Q3 2021.

7. CREDIT FACILITY

At December 31, 2022, 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 \$0.5 million at December 31, 2022.

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, 2022. 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, 2022 is 16.1. 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, 2022.

At the last review date of November 30, 2022, the credit facility was increased from \$8.5 million to \$25 million with no changes to significant terms.

8. 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 \$7.4 million (\$5.7 million at December 31, 2021). A risk-free rate of 3.29% and an inflation rate of 2.20% were used to calculate the best estimate of the decommissioning obligations compared to 1.52% and 2.20% respectively which were the rates used at December 31, 2021.

A reconciliation of the decommissioning obligations is provided below.

(\$)	December 31	December 31
	2022	2021
Balance, beginning of period	6,486	4,429
Liabilities incurred	1,398	1,686
Change in estimates	(1,788)	284
Accretion expense	177	87
Balance, end of period	6,273	6,486

9. LEASE LIABILITIES

The Company incurs lease payments related to office facilities. For the year ended December 31, 2022, finance expense of \$27,952 (\$37,933 for the year ended December 31, 2021) and repayment of lease liabilities of \$117,316 (\$108,335 for the year ended December 31, 2021) were recognized for a total cash outflow of \$146,268 (\$146,268 in 2021). Lease obligations contractually expire in January 2025.

10. 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 2022		December 31 2021	
	Number	Amount	Number	Amount
Common Shares				
Balance, beginning of period	75,250	\$75,228	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	75,250	\$75,228
Class B Common Non-Voting Shares				
Balance, beginning of period	6,370	\$64	6,370	\$64
Converted to common shares	(1,500)	(15)	-	-
Balance, end of period	4,870	\$49	6,370	\$64
Class C Common Non-Voting Shares				
Balance, beginning of period	12,480	\$124	12,480	\$124
Converted to common shares	(1,050)	(11)	-	-
Forfeited	(1,050)	(10)	-	-
Balance, end of period	10,380	\$103	12,480	\$124
Total		\$76,245		\$75,416

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 2023 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, 2022, 5,265,083 Class B shares and options have vested (6,264,750 at December 31, 2021).

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, 2021	743,500	\$0.73
Granted	189,250	0.15
Balance, December 31, 2021	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

The fair market value of each Class B share issued and option granted 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 (%)	1.18
Expected life (years)	3.1- 4.1
Estimated volatility of underlying common shares (%)	50
Share Price (\$)	1.20
Estimated forfeiture rate (%)	nil

The Company recognized share-based compensation expense of \$118,925 related to the Class B shares and options for the year ended December 31, 2022 (\$160,311 in 2021) and capitalized \$8,886 (\$5,353 in 2021).

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

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 within seven years from September 2016 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
2,154,000	\$1.50	\$1.00
2,154,000	\$2.00	\$1.15
2,154,000	\$2.25	\$1.30
2,154,000	\$2.50	\$1.45
2,154,000	\$2.75	\$1.60
2,154,000	\$3.00	\$1.75

The liquidity event price and the conversion price each increase 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, 2021	1,252,000	\$0.78
Granted	443,500	0.15
Balance, December 31, 2021	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

The fair market value of each Class C share issued and option granted 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 (%)	1.07
Expected life (years)	3.8
Estimated volatility of underlying common shares (%)	50
Share Price (\$)	1.10
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 \$57,646 related to the Class C non-voting shares for the year ended December 31, 2022 (\$71,803 in 2021) and capitalized \$5,467 (\$2,832 in 2021).

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

11. 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 2022	December 31 2021
Crude oil revenues	90,794	52,170
Natural gas revenues	19,805	9,059
Natural gas liquids revenues	5,734	2,651
Total	116,333	63,880

12. NET INCOME PER SHARE

	December 31 2022	December 31 2021
Net Income per share		
Basic	\$0.41	\$0.20
Diluted	\$0.39	\$0.20
Weighted average shares outstanding		
Basic	75,679	75,250
Diluted	79,555	76,782

13. 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 2022	December 31 2021
Net income before income tax	40,141	19,961
Canadian statutory income tax rate	23.00%	23.00%
Expected income tax at statutory rates	9,232	4,591
Add (deduct):		
Non-deductible share-based compensation and other	44	69
Provision for income tax	\$9,276	\$4,660
Current income tax	\$4,548	nil
Deferred income tax	\$4,728	\$4,660

The components of deferred income tax at December 31, 2022 and 2021 are as follows:

(\$)	December 31 2022	December 31 2021
Deferred income tax liability:		
Capital assets carrying value in excess of tax value	(15,296)	(11,255)
	(15,296)	(11,255)
Deferred income tax asset:		
Non-capital losses	-	611
Decommissioning obligations	1,443	1,492
Financing costs	57	84
	1,500	2,187
Deferred income tax	\$(13,796)	\$(9,068)

The Company had approximately \$83.4 million in available tax pools at December 31, 2022 (\$61.7 million at December 31, 2021). The Company recognized \$4.5 million of current income taxes in 2022 (nil in 2021).

14. 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 2022	December 31 2021
Salaries and other short-term benefits	2,635	1,880
Share-based compensation	144	155
Total	2,779	2,035

15. SUPPLEMENTAL CASH FLOW INFORMATION

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

(\$)	December 31 2022	December 31 2021
Source / (use) of cash:		
Accounts receivable	(3,916)	(3,413)
Prepaid expenses and deposits	(111)	(40)
Accounts payable and accrued liabilities	10,939	2,282
Current income taxes	4,548	-
Change in non-cash working capital	11,460	(1,171)
Related to:		
Operating activities	6,030	(994)
Investing activities	5,430	(177)

16. COMMITMENTS

The Company has an office lease commitment of \$146,000 per year for 2023 and 2024, and \$12,000 in 2025.

The Company has a four-year natural gas transportation commitment with an estimated annual cost of \$200,000 expected to begin in August 2023.

17. 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 \$8 million, which may be increased at the sole discretion of the party. At December 31, 2022, there is \$4.4 million remaining on the funding limit.

Subsequent to December 31, 2022, the funding limit on the Royalty Acquisition Agreement was increased to \$14 million.

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.

18. 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, 2022 and December 31, 2021, financial assets on the statement of financial position are comprised of cash and cash equivalents 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 25th day of the month following production. At December 31, 2022, 97% of the accounts receivable amount relates to production revenue (100% at December 31, 2021).

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, 2022 and December 31, 2021 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, 2022 and 2021.

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, 2022 and 2021.

Corporate Information

OFFICERS

Don Robson
President and Chief Executive Officer

Kim Schoenroth
*Vice President Finance and Chief
Financial Officer*

Gerald Aleman
Vice President, Production

Preston Kraft
Vice President, Operations

Steven Metzger
Vice President, Exploration

Lonny Tetley
Corporate Secretary

DIRECTORS

Clayton Woitas
Chairman

Tyson Birchall

Jeff Lebbert

Margaret McKenzie

Don Robson

Grant Zawalsky

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