SOURCE ROCK ROYALTIES LTD.

Statement of Reserves Data and Other Oil and Gas Information
(NI 51-101F1)

Effective December 31, 2024

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ABBREVIATIONS AND CONVERSION

In this document, the abbreviations set forth below have the following meanings:

bbl	barrel	Mcf	thousand cubic feet
mbbls	thousand barrels	mmcf	million cubic feet
MMbbl	million barrels	Mcf/d	thousand cubic feet per day
Bbl/d	barrels per day	MMBTU	million British Thermal Units
NGLs	natural gas liquids		
boe/d	barrels of oil equivalent per day		

AECO	A natural gas storage facility located at Suffield, Alberta.
API	American Petroleum Institute.
°API	An indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.
boe	Barrel of oil equivalent on the basis of 1 boe to 6 Mcf of natural gas. Boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6 Mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
Mcfe	1,000 cubic feet of gas equivalent.
mboe	1,000 barrels of oil equivalent.
$000s	Thousands of dollars.
WTI	West Texas Intermediate, the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade.

NOTES AND DEFINITIONS

The determination of oil and gas reserves involves the preparation of estimates that have an inherent degree of associated uncertainty. Categories of proved, probable and possible reserves have been established to reflect the level of these uncertainties and to provide an indication of the probability of recovery.

The estimation and classification of reserves requires the application of professional judgment combined with geological and engineering knowledge to assess whether or not specific reserves classification criteria have been satisfied. Knowledge of concepts including uncertainty and risk, probability and statistics, and deterministic and probabilistic estimation methods is required to properly use and apply reserves definitions.

"**Reserves**" are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically recoverable from discovered resources, from a given date forward, based on (a) analysis of drilling, geological, geophysical, and engineering data; (b) the use of established technology; and (c) specified economic conditions, which are generally accepted as being reasonable and shall be disclosed. 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.

"**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. In multi-well pools, it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to sub-divide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recorded from specific wells, facilities and completion intervals in the pool and their respective development and production status.

"**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.

The following terms used in this document have the following meanings:

"**Associated gas**" means the gas cap overlying a crude oil accumulation in a reservoir.

"**Company**" or "**Source Rock**" means Source Rock Royalties Ltd.

"**Crude oil**" or "**Oil**" means a mixture that consists mainly of pentanes and heavier hydrocarbons, which may contain sulphur and other non-hydrocarbon compounds, that is recoverable at a well from an underground reservoir and that is liquid at the conditions under which its volume is measured or estimated. It does not include solution gas or natural gas liquids.

"**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and the wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**Development well**" means a well drilled inside the established limits of an oil or gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

"**Dry Hole**" means a well drilled but incapable of producing economic quantities of oil or natural gas.

"**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property (sometimes referred to in part as "prospecting costs") and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies (collectively sometimes referred to as "geological and geophysical costs");

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defense, and the maintenance of land and lease records;

(c) dry hole contributions and bottom hole contributions;

(d) costs of drilling and equipping exploratory wells; and

(e) costs of drilling exploratory type stratigraphic test wells.

"**Exploratory well**" means a well that is not a development well, a service well or a stratigraphic test well.

"**Field**" means an area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field that are separated vertically by intervening impervious strata or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to denote localized geological features, in contrast to broader terms such as "basin", "trend", "province", "state", "play" or "area of interest".

"**Future prices and costs**" means future prices and costs that are:

(a) generally accepted as being a reasonable outlook of the future;

(b) if, and only to the extent that, there are fixed or presently determinable future prices or costs to which the Company issuer is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

"**Future income tax expenses**" means future income tax expenses estimated (generally, year-by-year):

(a) making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes, between oil and gas activities and other business activities;

(b) without deducting estimated future costs (for example, Crown royalties) that are not deductible in computing taxable income;

(c) taking into account estimated tax credits and allowances (for example, royalty tax credits); and

(d) applying to the future pre-tax net cash flows relating to the reporting issuer's oil and gas activities the appropriate year-end statutory tax rates, taking into account future tax rates already legislated.

"**Future net revenue**" means the estimated net amount to be received with respect to the development and production of reserves (including synthetic oil, coal bed methane and other non-conventional reserves) estimated using constant prices and costs or forecast prices and costs.

"**Gross**" means:

(a) in relation to the Company's interest in production or reserves, its "Company gross reserves", which are its working interest (operating or non-operating) share before deduction of royalties and without including any royalty interests of the Company;

(b) in relation to wells, the total number of wells in which the Company has an interest, and

(c) in relation to properties, the total area of properties in which the Company has an interest.

"**Natural gas**" means the lighter hydrocarbons and associated non-hydrocarbon substances occurring naturally in an underground reservoir, which under atmospheric conditions are essentially gases but which may contain natural gas liquids. Natural gas can exist in a reservoir either dissolved in crude oil (solution gas) or in a gaseous phase (associated gas or non-associated gas). Non-hydrocarbon substances may include hydrogen sulphide, carbon dioxide and nitrogen.

"**Natural gas liquids**" means those hydrocarbon components that can be recovered from natural gas as liquids including, but not limited to, ethane, propane, butanes, pentanes plus, condensate and small quantities of non-hydrocarbons.

"**Net**" means:

(a) in relation to the Company's interest in production or reserves its working interest (operating or non-operating) share after deduction of royalty obligations, plus its royalty interests in production or reserves;

(b) in relation to the Company's interest in wells, the number of wells obtained by aggregating the Company's working interest in each of its gross wells; and

(c) in relation to the Company's interest in a property, the total area in which the Company has an interest multiplied by the working interest owned by the Company.

"**Non-associated gas**" means an accumulation of natural gas in a reservoir where there is no crude oil.

"**Operating costs**" or "**production costs**" means costs incurred to operate and maintain wells and related equipment and facilities, including applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities.

"**Production**" means recovering, gathering, treating, field or plant processing (for example, processing gas to extract natural gas liquids) and field storage of oil and gas.

"**Property**" includes:

(a) fee ownership or a lease, concession, agreement, permit, licence or other interest representing the right to extract oil or gas subject to such terms as may be imposed by the conveyance of that interest;

(b) royalty interests, production payments payable in oil or gas, and other non-operating interests in properties operated by others; and

(c) an agreement with a foreign government or authority under which a reporting issuer participates in the operation of properties or otherwise serves as "producer" of the underlying reserves (in contrast to being an independent purchaser, broker, dealer or importer).

A property does not include supply agreements, or contracts that represent a right to purchase, rather than extract, oil or gas.

"**Property acquisition costs**" means costs incurred to acquire a property (directly by purchase or lease or indirectly by acquiring another corporate entity with an interest in the property), including:

(a) costs of lease bonuses and options to purchase or lease a property;

(b) the portion of the costs applicable to hydrocarbons when land including rights to hydrocarbons is purchased in fee;

(c) brokers' fees, recording and registration fees, legal costs and other costs incurred in acquiring properties.

"**Proved property**" means a property or part of a property to which reserves have been specifically attributed.

"**Reservoir**" means a porous and permeable underground formation containing a natural accumulation of producible oil or gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

"**Service well**" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt-water disposal, water supply for injection, observation, or injection for combustion.

"**Solution gas**" means natural gas dissolved in crude oil.

"**Stratigraphic test well**" means a drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Ordinarily, such wells are drilled without the intention of being completed for hydrocarbon production. They include wells for the purpose of core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic test wells are classified as (a) "exploratory type" if not drilled into a proved property; or (b) "development type", if drilled into a proved property. Development type stratigraphic wells are also referred to as "evaluation wells".

"**Support equipment and facilities**" means equipment and facilities used in oil and gas activities, including seismic equipment, drilling equipment, construction and grading equipment, vehicles, repair shops, warehouses, supply points, camps, and division, district or field offices.

"**Unproved property**" means a property or part of a property to which no reserves have been specifically attributed.

"**Well abandonment costs**" means costs of abandoning a well and surface lease reclamation. They do not include costs of abandoning the gathering system, suspended wells, batteries, plants, or processing facilities.

PART 1 - DATE OF STATEMENT

The effective date of the information being provided in this Form 51-101F1 is December 31, 2024 and is for the year ended December 31, 2024. The date of this statement is April 24, 2025 and the preparation date of the information being provided in this statement is April 8, 2025.

PART 2 - DISCLOSURE OF RESERVES DATA

2.1 Reserves Data (Forecast Prices and Costs)

The reserves data set forth below (the "**Reserves Data**") is based upon a report prepared by Trimble Engineering Associates Ltd., independent petroleum consultants, Calgary, Alberta, Canada ("**Trimble**"), evaluating the crude oil, natural gas and natural gas liquids ("**NGL**") reserves of Source Rock, as at December 31, 2024, dated April 8, 2025 (the "**Trimble Report**"). The Reserves Data summarizes the crude oil, NGL and natural gas reserves of the Company and the net present values of future net revenue for these reserves using forecast prices and costs. All of the Company's reserves are associated with royalty interests as it does not own any working interests.

The Trimble Report has been prepared in accordance with the standards contained in the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (the "**COGE Handbook**") and the reserve definitions contained in National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities adopted by the Canadian Securities Administrators ("**NI 51-101**") and the COGE Handbook. Additional information not required by NI 51-101 has been presented to provide continuity and additional information which Source Rock believes is important to the readers of this information. The Company engaged Trimble to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of Source Rock's reserves are in the Provinces of Alberta, Saskatchewan and Manitoba.

Source Rock determined the future net revenue and present value of future net revenue after income taxes by utilizing Trimble's before income tax future net revenue and Source Rock's estimate of income tax. Source Rock's estimates of the after income tax value of future net revenue have been prepared based on before income tax reserves information and include assumptions and estimates of its tax pools and the sequences of claims and rates of claim thereon. The values shown may not be representative of future income tax obligations, applicable tax horizon or after-tax valuation. The after-tax net present value of Source Rock's oil and gas properties reflects the tax burden of its properties on a stand-alone basis. It does not provide an estimate of the value of Source Rock as a business entity, which may be significantly different.

All evaluations of future net revenue are before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses.

It should not be assumed that the undiscounted or discounted net present value of future net revenue attributable to reserves estimated by Trimble represent the fair market value of those reserves. There is no assurance that the forecast price and cost assumptions contained in the Trimble Report will be attained and variations could be material. Other assumptions and qualifications relating to costs and other matters are summarized herein. The recovery and reserve estimates described herein are estimates only. The actual reserves associated with Source Rock's properties may be greater or less than those calculated.

The tables below summarize the data contained in the Trimble Report and, as a result, may contain slightly different numbers than such report due to rounding. Due to rounding, certain columns may not add exactly to the totals listed.

SUMMARY OF OIL AND GAS RESERVES
(Forecast Costs and Prices)

	Reserves									
	Light and Medium Crude Oil		Heavy Crude Oil		Conventional Natural Gas		Natural Gas Liquids		Total BOE	
Reserves Category	**Gross (mbbls)**	**Net (mbbls)**	**Gross (mbbls)**	**Net (mbbls)**	**Gross (mmcf)**	**Net (mmcf)**	**Gross (mbbls)**	**Net (mbbls)**	**Gross (mboe)**	**Net (mboe)**
Proved:										
Developed Producing	-	197.9	-	40.8	-	146.8	-	3.7	-	266.9
Developed Non-Producing	-	197.9	-	40.8	-	146.8	-	3.7	-	266.9
Undeveloped	-	65.5	-	35.6	-	13.0	-	0.6	-	103.9
Total Proved	-	263.4	-	76.4	-	159.7	-	4.3	-	370.8
Probable	-	151.0	-	54.9	-	54.1	-	1.6	-	216.4
Total Proved Plus Probable	-	414.3	-	131.3	-	213.8	-	5.9	-	587.2

Notes:

(1) Under NI 51-101, gross reserves include only working interests before the deduction of royalties payable and do not include royalties receivable. Net reserves are comprised of working interests minus royalties payable plus royalties receivable. Unlike typical oil and natural gas production companies which hold working interests, all of the Company's interests are royalties. As a result, the Company does not have any gross reserves attributed to its properties.

NET PRESENT VALUE SUMMARY

NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/YEAR) (Forecast Costs and Prices)

Reserves Category	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
Proved:					
Developed Producing	22,274.8	18,841.1	16,416.5	14,620.7	13,240.6
Developed Non-Producing	-	-	-	-	-
Undeveloped	9,362.9	7,086.7	5,718.4	4,785.1	4,101.6
Total Proved	31,637.7	25,927.8	22,134.9	19,405.8	17,342.2
Probable	21,108.8	13,642.2	9,790.9	7,478.4	5,962.8
Total Proved Plus Probable	52,746.5	39,570.0	31,925.7	28,884.3	23,305.0

NET PRESENT VALUE SUMMARY

NET PRESENT VALUES OF FUTURE NET REVENUE AFTER INCOME TAXES DISCOUNTED AT (%/YEAR) (Forecast Costs and Prices)

Reserves Category	**0% ($000s)**	**5% ($000s)**	**10% ($000s)**	**15% ($000s)**	**20% ($000s)**
Proved:					
Developed Producing	20,506.1	17,200.5	14,884.0	13,180.5	11,880.0
Developed Non-Producing	-	-	-	-	-
Undeveloped	7,618.2	5,620.6	4,466.0	3,699.9	3,149.6
Total Proved	28,124.3	22,821.1	19,349.9	16,880.4	15,029.6
Probable	16,973.9	10,679.6	7,552.6	5,716.9	4,531.4
Total Proved Plus Probable	45,098.3	33,500.8	26,902.5	22,597.2	19,561.0

FUTURE NET REVENUE (UNDISCOUNTED)
(Forecast Costs and Prices)

Reserves Category	Revenue ($000s)	Royalties ($000s)	Operating Costs ($000s)	Development Costs(1) ($000s)	Abandonment And Reclamation Costs(1) ($000s)	Future Net Revenue Before Income Taxes ($000s)	Income Taxes ($000s)	Future Net Revenue After Income Taxes ($000s)
Proved Developed Producing	22,274.8	-	-	-	-	22,274.8	1,768.7	20,506.1
Proved Undeveloped	9,362.9	-	-	-	-	9,362.9	1,744.7	7,618.2
Total Proved	31,637.7	-	-	-	-	31,637.7	3,513.4	28,124.3
Total Probable	21,108.8	-	-	-	-	21,108.8	4,134.9	16,973.9
Total Proved plus Probable	52,746.5	-	-	-	-	52,746.5	7,648.3	45,098.3

Notes:
(1) Unlike typical oil and natural gas production companies which hold working interests, all of the Company's interests are royalties. As a result, there are no operating costs, development costs or abandonment and reclamation costs associated with the estimated future net revenue from the reserves attributed to the Company's properties as it does not hold any working interests.

FUTURE NET REVENUE BY PRODUCT TYPE
(Forecast Costs and Prices)

RESERVES CATEGORY	PRODUCTION GROUP	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($000s)	Unit Value Before Income Tax (discounted at 10%/year) ($/boe)
Proved	Light and Medium Crude Oil (including solution gas and by-products)	17,521.8	66.53
	Heavy Oil (including ultra heavy, solution gas and by-products)	4,447.9	58.19
	Conventional Natural Gas (including by-products)	165.2	3.78
	Total	22,134.9	59.70
Proved plus Probable	Light and Medium Crude Oil (including solution gas and by-products)	24,769.7	59.78
	Heavy Crude Oil (including ultra heavy, solution gas and by-products)	6,963.8	53.03
	Conventional Natural Gas (including by-products)	192.2	3.57
	Total	31,925.7	54.37

Notes:
(1) Units Values are calculated by dividing the discounted future net revenue for the principal product of the production group.

PART 3 - PRICING ASSUMPTIONS

The following pricing assumptions were provided by Trimble.

3.1 **Forecast Prices used in Estimates for historical periods, and for the Trimble Report (effective January 1, 2025):**

	Oil(1)							
Year	WTI @ Cushing ($US/bbl)	Canadian Light Sweet(2) ($Cdn/bbl)	Hardisty Heavy Bow Riv(3) ($Cdn/bbl)	WCS(4) ($Cdn/bbl)	Hardisty Heavy(5) ($Cdn/bbl)	Cromer LSB(6) ($Cdn/bbl)	Inflation Rate(7) %/Year	Exchange Rate(8) ($US/$Cdn)
2025	72.00	95.00	82.00	82.00	75.00	95.00	-	0.72
2026	75.00	96.00	83.00	83.00	76.00	96.00	2.0	0.73
2027	76.00	97.00	84.00	84.00	77.00	97.00	2.0	0.75
2028	77.52	98.94	85.68	85.68	78.54	98.94	2.0	0.75
2029	79.07	100.92	87.39	87.39	80.11	100.92	2.0	0.75
2030	80.65	102.94	89.14	89.14	81.71	102.94	2.0	0.75
2031	82.26	105.00	90.92	90.92	83.35	105.00	2.0	0.75
Thereafter	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year		

	Gas(9)			Cond.(1)	But.(10)	Prop.(10)	Sulph.(10)		
Year	Henry Hub ($US/ mmbtu)	AECO Spot ($Cdn/ mmbtu)	B.C. Spot ($Cdn/ mmbtu)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/bbl)	($Cdn/lt)	Inflation Rate(7) %/Year	Exchange Rate(8) ($US/$Cdn)
2025	3.50	2.50	2.30	99.00	48.00	31.00	40.00	-	0.72
2026	3.75	3.40	3.30	100.00	49.00	32.00	40.00	2.0	0.73
2027	4.00	3.60	3.50	101.00	50.00	33.00	40.00	2.0	0.75
2028	4.08	3.67	3.57	103.02	51.00	33.66	40.80	2.0	0.75
2029	4.16	3.75	3.64	105.08	52.02	34.33	41.62	2.0	0.75
2030	4.24	3.82	3.71	107.18	53.06	35.02	42.45	2.0	0.75
2031	4.33	3.90	3.79	109.33	54.12	35.72	43.30	2.0	0.75
Thereafter	+2.0%/year	+2.0%/year	+2.0%/year	+2.0%/year	+2.0/year	+2.0%/year	+2.0%/year		

Notes:

(1) Oil and Condensate are subject to quality differentials and transportation.
(2) Light oil prices for 40.0 degrees API, 0.3% sulphur at Edmonton (Light Sweet Crude).
(3) Bow River Blend at Hardisty oil prices for 20-24 degrees API (Medium Sour Crude).
(4) Western Canada Select (WCS) prices at Hardisty (Heavy Sour Crude).
(5) Heavy oil prices for 12 degrees API at Hardisty (Heavy Sour Crude).
(6) Light oil prices for 35 degrees API at Cromer (Light Sour Blend).
(7) Inflation rates for forecasting prices and costs.
(8) Exchange rates used to generate the benchmark reference prices in this table.
(9) Alberta gas prices are quoted at AECO (NOVA Inventory Transfer - NIT), B.C gas prices at Station #2.
(10) Alberta reference price.
(11) Operating and capital costs are forecast to escalate at 2.0%.

Weighted average historical prices realized by the Company for the year ended December 31, 2024, were $89.79/bbl for light and medium crude oil, $80.09/bbl for heavy oil, $1.51/mcf for natural gas and $54.22/bbl for NGLs.

PART 4 - RECONCILIATION OF CHANGES IN RESERVES

4.1 Reserves Reconciliation

The following table sets forth a reconciliation of the changes in the Company's net reserves as at December 31, 2024, against such reserves as at December 31, 2023 (summarized in the tables above) based on the forecast price and cost assumptions evaluated in accordance with NI 51-101 definitions. As the Company only owns royalty interests, all of its reserves are net reserves.

Total Company	Light/Medium Oil			Heavy Oil		
Factors	**Net Proved (Mbbl)**	**Net Probable (Mbbl)**	**Net Proved Plus Probable (Mbbl)**	**Net Proved (Mbbl)**	**Net Probable (Mbbl)**	**Net Proved Plus Probable (Mbbl)**
December 31, 2023	267.0	123.4	390.4	67.6	38.5	106.1
Production	(68.3)	-	(68.3)	(14.8)	-	(14.8)
Technical Revisions	36.7	(13.5)	23.2	4.2	(5.8)	(1.6)
Extensions	11.5	3.3	14.9	8.7	4.0	12.7
Improved Recovery	16.5	37.8	54.3	10.7	18.2	28.8
Acquisitions	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-
December 31, 2024	**263.4**	**151.0**	**414.3**	**76.4**	**54.9**	**131.3**

Total Company	Conventional Natural Gas			NGL			Total BOE		
Factors	**Net Proved (MMcf)**	**Net Probable (MMcf)**	**Net Proved Plus Probable (MMcf)**	**Net Proved (Mbbl)**	**Net Probable (Mbbl)**	**Net Proved Plus Probable (Mbbl)**	**Net Proved (Mboe)**	**Net Probable (Mboe)**	**Net Proved Plus Probable (Mboe)**
December 31, 2023	106.4	36.2	142.6	1.8	0.7	2.5	354.2	168.5	522.7
Production	(28.6)	-	(28.6)	(1.3)	-	(1.3)	(89.1)	-	(89.1)
Technical Revisions	78.3	14.9	93.2	3.4	0.7	4.1	57.4	(16.1)	41.3
Extensions	1.1	0.3	1.3	0.2	-	0.2	20.6	7.4	28.0
Improved Recovery	2.6	2.7	5.3	0.2	0.2	0.4	27.8	56.6	84.3
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	-	-	-	-	-	-	-	-	-
Economic Factors	-	-	-	-	-	-	-	-	-
December 31, 2024	**159.8**	**54.1**	**213.8**	**4.3**	**1.6**	**5.9**	**370.8**	**216.4**	**587.2**

Reserve Change Category Descriptions:

Production: Reductions due to production during the time period being reconciled

Technical Revisions: Positive or negative changes resulting from new technical data or revised interpretations of previously assigned reserves

Extensions: Additions for step-out drilling in previously discovered/booked reservoirs

Acquisitions: Additions related to purchasing oil and gas assets

Dispositions: Reductions related to selling oil and gas assets

Economic Factors: Changes due to different price forecasts, inflation rates, and regulatory changes

PART 5 - ADDITIONAL INFORMATION RELATING TO RESERVES DATA

5.1 Undeveloped Reserves

The Trimble Report contains proved and probable undeveloped reserves that have been estimated in accordance with the procedures and standards contained in the COGE Handbook. The undeveloped reserves in the Trimble Report relate to locations that are within actively developed plays, supported by existing well control, and adjacent to existing production.

The Company anticipates that approximately 85% of the undeveloped reserves will be developed within the next five years; nevertheless, the development of the undeveloped reserves will be dependent on commodity prices and it may be more than five years until they are developed. The development of undeveloped reserves is not within the control of the Company as it only holds a royalty interest in such reserves and therefore does not have control or influence on the development of such reserves.

Unlike typical oil and natural gas production companies which hold working interests, all of the Company's interests are royalties. As a result, the Company does not have any gross reserves attributed to its royalty lands and all reserves (including undeveloped reserves) are net reserves.

The following tables set forth the net proved undeveloped reserves and the net probable undeveloped reserves, each by product type, attributed to Source Rock for the year ended December 31, 2024 based on forecast prices and costs.

5.1.1 Proved Undeveloped Reserves

Proved undeveloped reserves are generally those reserves related to wells that have been tested and not yet tied-in, wells drilled near the end of the fiscal year or wells further away from gathering systems. In addition, such reserves may relate to planned infill-drilling locations. The majority of these reserves are planned to be on stream within a two-year timeframe. The majority of the proved undeveloped reserves in the Trimble Report relate to the Company’s royalties in S.E. Saskatchewan and the Figure Lake area of central Alberta.

SUMMARY OF PROVED UNDEVELOPED RESERVES (Forecast Prices & Costs)

	Light and Medium Crude Oil (mbbls)		Heavy Crude Oil (mbbls)		Conventional Natural Gas (mmcf)		NGLs (mbbls)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2022	5.2	8.1	-	0.6	0.2	13.9	0.0	0.2
2023	32.6	54.9	24.4	28.9	0.7	17.0	0.0	0.2
2024	17.5	65.5	10.7	35.6	2.9	13.0	0.2	0.6

5.1.2 Probable Undeveloped Reserves

Probable reserves are generally reserves tested or indicated by analogy to be productive, infill drilling locations and lands contiguous to production. The majority of the probable undeveloped reserves in the Trimble Report relate to the Company's royalties in S.E. Saskatchewan and the Figure Lake area of central Alberta.

SUMMARY OF PROBABLE UNDEVELOPED RESERVES (Forecast Prices & Costs)

	Light and Medium Oil (mbbls)		Heavy Oil (mbbls)		Natural Gas (mmcf)		NGLs (mbbls)	
Year	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End	First Attributed	Cumulative at Year End
2022	7.5	62.4	-	1.3	0.1	11.6	0.0	0.1
2023	31.0	96.7	21.6	26.7	1.5	15.8	0.1	0.3
2024	38.3	118.7	18.2	41.1	2.9	12.8	0.2	0.5

5.2 Significant Factors or Uncertainties

The evaluated oil and gas properties of the Company have no material extraordinary risks or uncertainties beyond those which are inherent of an oil and gas producing company. Some of these risks are noted below.

The process of estimating reserves is complex. Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and natural gas prices and costs change. Estimates are reviewed and revised, either upward or downward, as warranted by newly acquired information.

The evaluation and drilling of hydrocarbon targets may be curtailed, delayed or cancelled by the unavailability or prevailing cost of drilling rigs or technical contractors, mechanical difficulties, adverse weather and ocean conditions, environmental issues, political or social unrest, technical hazards, such as unusual or unexpected formations or pressures or because of issues related to compliance with government regulations or requirements. Drilling may result in unprofitable efforts, not only with respect to dry wells, but also with respect to wells which, though yielding some hydrocarbons, are not sufficiently productive to economically justify commercial development. Furthermore, the successful completion of a well does not assure a profit on investment or the recovery of drilling, completion and operating costs.

The Company does not control or even have influence over the techniques used to drill and complete wells on its royalty lands and nor does it generally have any control or influence over the timing of such activity.

5.3 Future Development Costs

No development costs were deducted in the estimation of the future net revenues attributable to the proved and probably reserves of the Company. No capital expenditures were anticipated for the Company's oil and gas interests, which are limited to royalty interests.

As funding for future development costs will be the responsibility of the working interest owners on the properties in which the Company owns royalty interests, and as the Company does not hold any working interests in any oil and gas properties, the Company will not be responsible for any development costs on the properties in which it owns royalty interests and cannot advise as to the sources and costs of funding future development or the impact thereof on disclosed reserves or future net revenue.

PART 6 - OTHER OIL AND GAS INFORMATION

6.1 Oil and Gas Properties and Wells

The following table sets forth the number of gross wells in which the Company held a royalty interest as at December 31, 2024, all of which are located in Alberta, Saskatchewan and Manitoba. As the Company does not hold any working interests, the net number of wells located on the Company's properties is nil.

	Natural Gas		Oil	
	Producing	**Non-Producing(1)**	**Producing**	**Non-Producing(1)**
Alberta	15	-	169	-
Manitoba	-	-	2	-
Saskatchewan	30	-	752	-
Total	**45**	**-**	**923**	**-**

Notes:

(1) The Company does not have information from third parties on non-producing wells located on its royalty lands because royalty revenues payable by third parties are based on producing wells located on its royalty lands and no information is provided with respect to non-producing wells.

The following is a description of Source Rock's important properties as of December 31, 2024:

S.E. Saskatchewan

Source Rock owns varying GORRs in approximately 35,000 gross acres of land located in southeast Saskatchewan (the "S.E. Saskatchewan GORR Lands"). The S.E. Saskatchewan GORR Lands produce predominately light oil from multiple formations, including but not limited to the Frobisher, Midale, Bakken, Tilston, Souris Valley and Lower Waterous-Alida. As at December 31, 2024, there were approximately 180 non-unitized producing wellbores on the S.E. Saskatchewan GORR Lands and royalty production net to Source Rock averaged approximately 107 boe/d during 2024. Source Rock also owns varying GORRs in 6 units in S.E. Saskatchewan. During the year ended December 31, 2024, 20 gross new horizontal wells began producing on the S.E. Saskatchewan GORR Lands. The S.E. Saskatchewan GORR Lands provide insulation from any potential Alberta and western Saskatchewan oil price differential widening that may occur in the future due to oil from these lands being sold at Cromer, Manitoba.

Figure Lake, Clearwater

Source Rock owns a 1.5% GORR in approximately 61,000 largely contiguous acres of land located in central Alberta (the "Clearwater GORR Lands"). The Clearwater GORR Lands produce heavy oil from the Clearwater formation. As at December 31, 2024, there were 59 producing wellbores on the Clearwater GORR Lands and royalty production net to Source Rock averaged approximately 42 boe/d (100% heavy oil) during the month of December 2024.

Hamilton Lake, Alberta

Source Rock's owns a production volume royalty (the "PVR") in lands located in east-central Alberta, specifically relating to crude oil from the "Viking formation" (as defined by the Alberta Energy Regulator at any given time). The PVR is predominately supported by production from the Hamilton Lake Unit. Pursuant to the royalty agreement governing the PVR, Source Rock's remaining entitlement to royalty volumes from the Hamilton Lake Unit is as follows:

- 2025 - 70 bbl/d;
- 2026 - 39 bbl/d;
- 2027 to 2034 - 20% lower on a per day basis than the prior calendar year; and
- January 1, 2035 - conversion to a 0.50% GORR in the Hamilton Lake Unit or a $500,000 pay-out, at the discretion of the royalty payor.

6.2 Properties With No Attributed Reserves

All of the Company's interests are royalties. All of the Company's royalty lands, inclusive of those with no attributed reserves, are located in the Western Canadian Sedimentary Basin. As the Company does not hold any working interests, the Company relies to some extent on information from third party royalty payors. Royalty revenues payable by third parties, and the reporting provided relating to such royalty revenues, are derived from the Company's royalty lands that are producing and therefore have reserves attributed. Consistent reporting is not provided to the Company for its royalty lands that are not producing (being those properties with no attributed reserves). These third parties are not always obligated to, and may not always, update the Company with respect to new information and developments relating to these properties with no attributed reserves.

As the Company does not hold any working interests in its royalty lands, the net acres associated with its royalty lands are nil. In addition, the Company is not responsible for, nor subject to, any work commitments. Similarly, the Company does not have the ability to control the expiration, surrender or continuation of rights to explore, develop and exploit any properties with no attributed reserves.

6.3 Forward Contracts

The Company does not currently have exposure to any forward contracts.

6.4 Additional Information Concerning Abandonment and Reclamation Costs

As the Company only owns royalty interests, it is not responsible for any abandonment or reclamation costs associated with its oil and gas properties.

6.5 Tax Horizon

As at December 31, 2024, the Company had federal tax pools of approximately $22,100,329. The statutory corporate income tax rate applicable to the Company is approximately 23%. A corporation's taxable income is based on total revenue, other income and expenses. The Company paid cash taxes for 2024 and expects to pay cash taxes for the year ended 2025 and onward, with the anticipated amount of taxes being materially influenced by, among other factors, royalty production volumes, commodity prices, development activities on the properties in which it owns royalties, changes in tax laws, newly acquired tax pools via acquisitions of additional royalties (and the timing thereof), and the Company's other business activities.

6.6 Costs Incurred

There were no acquisition, development or exploration costs incurred in respect of the Company's royalty lands for the year ended December 31, 2024, other than property acquisition costs of $27,103 for unproved properties.

6.7 Exploration and Development Activities

The following table summarizes the gross number of wells drilled and completed on the Company's royalty lands during the year ended December 31, 2024. Wells drilled on new royalty lands prior to the Company acquiring such royalty lands were excluded from this summary information. As the Company does not hold any working interests, the net number of wells drilled and completed by the Company on its royalty lands was nil.

	Saskatchewan / Manitoba, Canada		**Alberta, Canada**	
	Exploratory Wells	**Development Wells**	**Exploratory Wells**	**Development Wells**
Activity	Gross	Gross	Gross	Gross
Oil Wells	-	24	-	19
Gas Wells	-	-	-	-
Service Wells	-	-	-	-
Stratigraphic Test Wells	-	-	-	-
Dry Holes	-	-	-	-
Totals Wells	**-**	**24**	**-**	**19**

6.8 Production Estimates

The following table discloses for each product type the total volume of production estimated by Trimble for 2025 in the estimates of future net revenue from the forecast case of proved plus probable reserves disclosed above under the heading "Disclosure of Reserves Data".

	Crude Oil		Conventional Natural Gas		NGL		Barrels of oil Equivalent	
Reserves Category	**Gross(1)(3) (bbls/d)**	**Net(2)(3) (bbls/d)**	**Gross(1)(3) (mcf/d)**	**Net(1)(3) (mcf/d)**	**Gross(2)(3) (bbls/d)**	**Net(2)(3) (bbls/d)**	**Gross(1)(3) (boe/d)**	**Net(2)(3) (boe/d)**
Proved	-	196	-	79	-	3	-	212
Probable	-	18	-	2	-	-	-	18
Total Proved Plus Probable	-	214	-	81	-	3	-	230

Notes:

(1) All of the Company's interests in reserves are royalties with no associated working interests. As a result, there is no gross production associated with the Company's royalty lands.
(2) Net production represents the Company's royalty production.
(3) Including by-products but excluding solution gas.

Other than the Hamilton Lake Unit, no field accounts for more than 20% of the production estimate. The Company's net production estimated by Trimble for the year ended December 31, 2025 from the Hamilton Lake Unit is 70 bbl/d of light crude oil.

6.9 Production History

The following tables summarize certain information in respect of the Company's average royalty production, product prices received and the resulting netback from its royalty lands for the periods indicated below:

	Quarter Ended			
	December 31, 2024	**September 30, 2024**	**June 30, 2024**	**March 31, 2024**
Average Daily Royalty Production(1)				
Light and Medium Crude Oil (bbl/d)(2)	197	202	197	182
Heavy Crude Oil (bbl/d)(2)	44	35	36	40
Conventional Natural Gas (mcf/d)	49	88	70	79
NGLs (bbl/d)	7	6	6	6
Combined (boe/d)	256	257	251	241
Average Product Price Received				
Light and Medium Crude Oil ($/bbl)(2)	87.42	91.28	98.86	87.42
Heavy Crude Oil (bbl/d)(2)	77.99	80.97	88.66	77.99
Conventional Natural Gas ($/mcf)	2.11	0.45	1.11	2.68
NGLs (bbl/d)	58.66	56.71	56.45	55.22
Combined Realized Price ($/boe) (3)	79.45	83.94	92.06	78.78

Notes:

(1) Represents the Company's royalty share of production.
(2) Includes by-products but excludes solution gas.
(3) Unlike typical oil and natural gas production companies which hold working interests, all of the Company's interests are royalties. As a result, (a) no royalties are payable with respect to the Company's share of royalty production, (b) the Company does not incur production or operating costs, and (c) the Company's "netback" as that term is defined in NI 51-101 is equivalent to its price received.

The Hamilton Lake Unit contributed approximately 30% of Source Rock's average royalty production for the year ended December 31, 2024. The Company's royalty production for the year ended December 31, 2024 from the Hamilton Lake Unit was 75 bbl/d of light crude oil.

Production Volume by Area

The following table discloses the Company's royalty production volumes by area (on a net basis) for the year ended December 31, 2024, and by each product type:

Area	2024 Company Net				
	Light and Medium Oil	Heavy Oil	NGL	Natural Gas	Total
Canada	bbl/d	bbl/d	bbl/d	Mcf/d	boe/d
Alberta					
East-central	75	2	0	1	77
West-central	4	0	1	40	12
Central	15	37	0	0	53
Saskatchewan					
West-central	3	0	0	3	3
Southeast	98	0	5	27	107
Total	**231**	**39**	**6**	**72**	**251**