2024
ANNUAL REPORT

COELACANTH ENERGY INC.

ABOUT COELACANTH

The name Coelacanth and success go hand-in-hand. Coelacanth (pronounced see-luh-kanth) is a prehistoric fish dating back 410 million years. This species was thought to be long extinct – until discovered off the coast of Indonesia in 1938. It is a survivor!

Coelacanth fossils are common to the Montney formation, where our oil & gas exploration and development company operates and has identified extensive opportunities. In a sea of sameness, our brand is dynamic, modern, distinct… and defies expectation. A true reflection of the company and the people behind it.

COELACANTH
ENERGY INC.

Q4 2024 FINANCIAL AND OPERATING RESULTS

2024 HIGHLIGHTS

- Drilled and completed three Lower Montney wells and completed a previously drilled Upper Montney well on its 5-19 pad at Two Rivers East. Average test production from the three Lower Montney wells was 1,624 boe/d (61% light oil) and test production from the Upper Montney well was 1,338 boe/d (54% light oil). (5)
- Secured revolving bank credit facilities for a total of $52.0 million from a Canadian chartered bank.
- Substantially completed construction of pipelines to connect the 5-19 pad wells to the Two Rivers East facility.
- Initiated construction of its Two Rivers East facility for a Q2 2025 on-stream date.

FINANCIAL RESULTS	**Three Months Ended December 31**			**Year Ended December 31**		
($000s, except per share amounts)	**2024**	2023	% Change	**2024**	2023	% Change
Oil and natural gas sales	**4,544**	4,204	8	**13,736**	6,663	106
Cash flow from (used in) operating activities	**3,157**	(404)	(881)	**2,203**	(4,234)	(152)
Per share - basic and diluted (3)	**0.01**	(-)	(100)	**-**	(0.01)	(100)
Adjusted funds flow (used) (1)	**382**	1,750	(78)	**1,515**	(333)	(555)
Per share - basic and diluted	**-**	-	-	**-**	(-)	(-)
Net loss	**(2,903)**	(750)	287	**(8,897)**	(6,573)	35
Per share - basic and diluted	**(0.01)**	(-)	100	**(0.02)**	(0.01)	100
Capital expenditures (4)	**64,952**	34,656	87	**84,497**	74,613	13
Adjusted working capital (deficiency) (2)				**(18,637)**	67,589	(128)
Common shares outstanding (000s)						
Weighted average - basic and diluted	**530,398**	478,731	11	**529,804**	439,055	21
End of period - basic				**530,670**	528,650	-
End of period - fully diluted				**615,930**	609,989	1

(1) Adjusted funds flow (used) and adjusted funds flow (used) per share do not have any standardized meaning prescribed by IFRS Accounting Standards ("IFRS") and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP and Other Financial Measures" section in the MD&A for more details and the "Cash Flow From (Used in) Operating Activities and Adjusted Funds Flow (Used)" section in the MD&A for a reconciliation from cash flow from (used in) operating activities.

(2) Adjusted working capital (deficiency) is a capital management measure calculated as current assets and restricted cash deposits less current liabilities, excluding the current portion of decommissioning obligations. Please refer to the "Non-GAAP and Other Financial Measures" section in the MD&A for more details.

(3) Supplemental financial measure. Please refer to the "Non-GAAP and Other Financial Measures" section in the MD&A for more details.

(4) Capital expenditures does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP and Other Financial Measures" section in the MD&A for more details.

(5) See "Test Results and Initial Production Rates" section in the MD&A for more details.

OPERATING RESULTS [1]	Three Months Ended December 31 **2024**	2023	% Change	Year Ended December 31 **2024**	2023	% Change
Daily production [2]						
Oil and condensate (bbls/d)	**473**	419	13	**320**	139	130
Other NGLs (bbls/d)	**29**	28	4	**34**	16	113
Oil and NGLs (bbls/d)	**502**	447	12	**354**	155	128
Natural gas (mcf/d)	**3,490**	2,858	22	**3,648**	1,624	125
Oil equivalent (boe/d)	**1,084**	923	17	**962**	426	126
Oil and natural gas sales						
Oil and condensate ($/bbl)	**87.06**	87.38	(-)	**89.46**	88.94	1
Other NGLs ($/bbl)	**33.28**	32.32	3	**33.22**	33.22	-
Oil and NGLs ($/bbl)	**83.97**	83.88	-	**83.99**	83.28	1
Natural gas ($/mcf)	**2.07**	2.86	(28)	**2.14**	3.26	(34)
Oil equivalent ($/boe)	**45.57**	49.47	(8)	**39.01**	42.82	(9)
Royalties						
Oil and NGLs ($/bbl)	**16.86**	19.38	(13)	**18.70**	20.24	(8)
Natural gas ($/mcf)	**0.13**	0.26	(50)	**0.21**	0.57	(63)
Oil equivalent ($/boe)	**8.22**	10.20	(19)	**7.66**	9.57	(20)
Operating expenses						
Oil and NGLs ($/bbl)	**8.34**	11.57	(28)	**9.47**	13.25	(29)
Natural gas ($/mcf)	**1.25**	1.28	(2)	**1.58**	2.21	(29)
Oil equivalent ($/boe)	**7.88**	9.57	(18)	**9.47**	13.25	(29)
Net transportation expenses [3]						
Oil and NGLs ($/bbl)	**5.54**	4.95	12	**3.46**	4.10	(16)
Natural gas ($/mcf)	**0.76**	0.81	(6)	**0.73**	1.12	(35)
Oil equivalent ($/boe)	**5.01**	4.92	2	**4.04**	5.75	(30)
Operating netback (loss) [4]						
Oil and NGLs ($/bbl)	**53.23**	47.98	11	**52.36**	45.69	15
Natural gas ($/mcf)	**(0.07)**	0.51	(114)	**(0.38)**	(0.64)	(41)
Oil equivalent ($/boe)	**24.46**	24.78	(1)	**17.84**	14.25	25
Depletion and depreciation ($/boe)	**(10.76)**	(12.18)	(12)	**(13.59)**	(14.93)	(9)
General and administrative expenses ($/boe)	**(15.46)**	(10.77)	44	**(14.34)**	(27.08)	(47)
Share based compensation ($/boe)	**(7.08)**	(16.31)	(57)	**(11.12)**	(23.49)	(53)
Loss on lease termination ($/boe)	**(2.02)**	-	100	**(0.57)**	-	100
Finance expense ($/boe)	**(18.02)**	(1.28)	1,308	**(6.33)**	(3.09)	105
Finance income ($/boe)	**3.65**	10.01	(64)	**8.23**	18.75	(56)
Unutilized transportation ($/boe)	**(3.88)**	(3.08)	26	**(5.37)**	(6.65)	(19)
Net loss ($/boe)	**(29.11)**	(8.83)	230	**(25.25)**	(42.24)	(40)

(1) "bbls" and "bbls/d" refers to barrels and barrels per day, "mcf" and "mcf/d" refers to thousand cubic feet and thousand cubic feet per day, and "boe" and "boe/d" refers to barrels of oil equivalent and barrels of oil equivalent per day. Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. A boe conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent has been used for the calculation of boe amounts in the MD&A. This boe conversion rate is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) "Natural gas" refers to shale gas; "Oil and condensate" refers to condensate and tight oil combined; "Other NGLs" refers to butane, propane and ethane combined; "Oil and NGLs" refers to tight oil, and NGLs combined; "Oil equivalent" refers to the total oil equivalent of shale gas, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent as described above. Readers are referred to the "Product Types" section in the MD&A for a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, tight oil, and NGLs.

(3) Net transportation expenses does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP and Other Financial Measures" section in the MD&A for more details and the "Net Transportation Expenses" section in the MD&A for reconciliations from transportation expenses.

(4) Operating netback does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP and Other Financial Measures" section in the MD&A for more details and the "Operating Netback" section in the MD&A for reconciliations from net loss.

MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

April 23, 2025

The MD&A should be read in conjunction with the audited financial statements and related notes for the years ended December 31, 2024 and 2023. The audited financial statements and financial data contained in the MD&A have been prepared in accordance with IFRS Accounting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are expressed in Canadian currency, unless otherwise noted.

DESCRIPTION OF BUSINESS

Coelacanth Energy Inc. ("Coelacanth" or the "Company") is an oil and natural gas company, actively engaged in the acquisition, development, exploration, and production of oil and natural gas reserves in northeastern British Columbia, Canada. The Company trades on the TSX Venture Exchange ("TSXV") under the symbol "CEI".

OIL AND GAS TERMS

The Company uses the following frequently recurring oil and gas industry terms in the MD&A:

Liquids

Bbls	Barrels
Bbls/d	Barrels per day
NGLs	Natural gas liquids (includes condensate, pentane, butane, propane, and ethane)
Condensate	Pentane and heavier hydrocarbons

Natural Gas

Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
MMcf/d	Millions of cubic feet per day
MMbtu	Million of British thermal units
MMbtu/d	Million of British thermal units per day

Oil Equivalent

Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day

Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. A boe conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent has been used for the calculation of boe amounts in the MD&A. This boe conversion rate is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NOTE REGARDING PRODUCT TYPES

The Company uses the following references to sales volumes in the MD&A:

Natural gas refers to shale gas
Oil and condensate refers to condensate and tight oil combined
Other NGLs refers to butane, propane and ethane combined
Oil and NGLs refers to tight oil and NGLs combined
Oil equivalent refers to the total oil equivalent of shale gas, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent as described above.

Readers are referred to the "Product Types" section for a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, tight oil, and NGLs.

NON-GAAP AND OTHER FINANCIAL MEASURES

This MD&A refers to certain measures that are not determined in accordance with IFRS (or "GAAP"). These non-GAAP and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-GAAP and other financial measures should not be considered alternatives to, or more meaningful than, financial measures that are determined in accordance with IFRS as indicators of the Company's performance. Management believes that the presentation of these non-GAAP and other financial measures provides useful information to shareholders and investors in understanding and evaluating the Company's ongoing operating performance, and the measures provide increased transparency to better analyze the Company's performance against prior periods on a comparable basis.

Non-GAAP Financial Measures

Adjusted funds flow (used)
Management uses adjusted funds flow (used) to analyze performance and considers it a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and abandonment obligations and to repay debt, if any. Adjusted funds flow (used) is a non-GAAP financial measure and has been defined by the Company as cash flow from (used in) operating activities excluding the change in non-cash working capital related to operating activities, movements in restricted cash deposits and expenditures on decommissioning obligations. Management believes the timing of collection, payment or incurrence of these items involves a high degree

of discretion and as such may not be useful for evaluating the Company's cash flows. Adjusted funds flow (used) is reconciled from cash flow from (used in) operating activities under the heading "Cash Flow From (Used in) Operating Activities and Adjusted Funds Flow (Used)".

Net transportation expenses
Management considers net transportation expenses an important measure as it demonstrates the cost of utilized transportation related to the Company's production. Net transportation expenses is calculated as transportation expenses less unutilized transportation and is calculated as follows:

	Three Months Ended December 31		Year Ended December 31	
($000s)	**2024**	2023	**2024**	2023
Transportation expenses	**887**	680	**3,313**	1,930
Unutilized transportation	**(387)**	(262)	**(1,891)**	(1,035)
Net transportation expenses (non-GAAP)	**500**	418	**1,422**	895

Operating netback
Management considers operating netback an important measure as it demonstrates its profitability relative to current commodity prices. Operating netback is calculated as oil and natural gas sales less royalties, operating expenses, and net transportation expenses and is calculated as follows:

	Three Months Ended December 31		Year Ended December 31	
($000s)	**2024**	2023	**2024**	2023
Oil and natural gas sales	**4,544**	4,204	**13,736**	6,663
Royalties	**(820)**	(866)	**(2,698)**	(1,489)
Operating expenses	**(786)**	(813)	**(3,335)**	(2,062)
Net transportation expenses	**(500)**	(418)	**(1,422)**	(895)
Operating netback (non-GAAP)	**2,438**	2,107	**6,281**	2,217

Capital expenditures
Coelacanth utilizes capital expenditures as a measure of capital investment on property, plant, and equipment, exploration and evaluation assets and property acquisitions compared to its annual budgeted capital expenditures. Capital expenditures are calculated as follows:

	Three Months Ended December 31		Year Ended December 31	
($000s)	**2024**	2023	**2024**	2023
Capital expenditures – property, plant, and equipment	**233**	4,584	**1,206**	26,928
Capital expenditures – exploration and evaluation assets	**64,719**	30,072	**83,291**	47,685
Capital expenditures (non-GAAP)	**64,952**	34,656	**84,497**	74,613

Capital Management Measures

Adjusted working capital (deficiency)
Management uses adjusted working capital (deficiency) as a measure to assess the Company's financial position. Adjusted working capital is calculated as current assets and restricted cash deposits less current liabilities, excluding the current portion of decommissioning obligations. Refer to the calculation of adjusted working capital and reconciliation to working capital under the heading "Liquidity and Capital Resources".

Non-GAAP Financial Ratios

Adjusted funds flow (used) per share
Adjusted funds flow (used) per share is a non-GAAP financial ratio, calculated using adjusted funds flow (used) and the same weighted average basic and diluted shares used in calculating net loss per share.

Net transportation expenses per boe
The Company utilizes net transportation expenses per boe to assess the per unit cost of utilized transportation related to the Company's production. Net transportation expenses per boe is calculated as net transportation expenses divided by total production for the applicable period. Net transportation expenses per boe is reconciled to transportation expenses per boe under the heading "Net Transportation Expenses".

Operating netback per boe
The Company utilizes operating netback per boe to assess the operating performance of its petroleum and natural gas assets on a per unit of production basis. Operating netback per boe is calculated as operating netback divided by total production for the applicable period. Operating netback per boe is reconciled to net loss per boe under the heading "Operating Netback".

Supplementary Financial Measures

The supplementary financial measures used in this MD&A (primarily average sales price per product type, royalty rates, and certain per boe and per share figures) are either a per unit disclosure of a corresponding GAAP measure, or a component of a corresponding GAAP measure, presented in the financial statements. Supplementary financial measures that are disclosed on a per unit basis are calculated by dividing the aggregate GAAP measure (or component thereof) by the applicable unit for the period. Supplementary financial measures that are disclosed on a component basis of a corresponding GAAP measure are a granular representation of a financial statement line item and are determined in accordance with GAAP.

OPERATIONS UPDATE

In Q4 2024, Coelacanth achieved two more significant milestones in its vision of moving the Two Rivers Montney Project from a large Montney land block to a proven resource with decades of inventory.

In 2022 and 2023, Coelacanth was able to prove productivity in the Lower Montney over a significant portion of lands at Two Rivers that allowed for the decision to build-out infrastructure and to continue pad drilling at Two Rivers East. During 2024, Coelacanth completed the licensing phase of the infrastructure and started construction while also continuing to develop the Montney resource.

In Q4 2024, Coelacanth was able to substantially complete all pipelines required for its 5-19 pad that connected it from the pad to the future facility and then on to a midstream gathering system. Concurrently, Coelacanth completed a successful Upper Montney well at Two Rivers East and changed the completion design in the Lower Montney on the 5-19 pad. The Upper Montney completion proved significant productivity (previously announced test rate of 1,136 boe/d) (1) in a zone that can be mapped over a significant portion of Coelacanth's lands and should materially increase drilling inventory. The new Lower Montney completions yielded increased overall test rates as well as increasing the oil percentage (3-well average test rates previously announced at 1,624 boe/d with 61% light oil) (1) pointing to potentially higher per-well recoveries of oil and gas and corresponding per-well values than previously estimated.

Construction of the facility continued throughout Q1 2025 and is now substantially complete. With 9 wells and over 11,000 boe/d (1) of test production waiting on completion of the facility, we anticipate yet another major milestone will be reached imminently. We look forward to reporting updates on the Two Rivers East project as new developments arise.

(1) See "Test Results and Initial Production Rates" section for more details.

SUMMARY OF FINANCIAL RESULTS

($000s, except per share amounts)	Three Months Ended December 31 **2024**	2023	% Change	Year Ended December 31 **2024**	2023	2022
Oil and natural gas sales	**4,544**	4,204	8	**13,736**	6,663	7,833
Cash flow from (used in) operating activities	**3,157**	(404)	(881)	**2,203**	(4,234)	(9,741)
Per share - basic and diluted (3)	**0.01**	(-)	(100)	**-**	(0.01)	(0.03)
Adjusted funds flow (used) (1)	**382**	1,750	(78)	**1,515**	(333)	(350)
Per share - basic and diluted	**-**	-	(-)	**-**	(-)	(-)
Net loss	**(2,903)**	(750)	287	**(8,897)**	(6,573)	(11,163)
Per share - basic and diluted	**(0.01)**	(-)	100	**(0.02)**	(0.01)	(0.03)
Total assets				**213,038**	208,994	114,029
Total long-term liabilities				**7,775**	7,721	8,051
Adjusted working capital (deficiency) (2)				**(18,637)**	67,589	67,738

(1) Adjusted funds flow (used) and adjusted funds flow (used) per share do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP and Other Financial Measures" section for more details and the "Cash Flow From (Used in) Operating Activities and Adjusted Funds Flow (Used)" section for a reconciliation from cash flow from (used in) operating activities.

(2) Adjusted working capital (deficiency) is a capital management measure calculated as current assets and restricted cash deposits less current liabilities, excluding the current portion of decommissioning obligations. Please refer to the "Non-GAAP and Other Financial Measures" section for more details.

(3) Supplemental financial measure. Please refer to the "Non-GAAP and Other Financial Measures" section for more details.

Oil and natural gas sales, cash flow from operating activities, and adjusted funds flow increased in 2024 compared to 2023 mainly due to an increase in oil and natural gas production stemming from two new wells at Two Rivers West placed on production in Q4 2023.

Net loss increased in 2024 compared to 2023 mainly as the result of $1.7 million of third party fees to secure the initial one-year term of a $45.0 million credit facility and increased depletion and depreciation expense resulting from increased production.

PRODUCTION	Three Months Ended December 31			Year Ended December 31		
	2024	2023	% Change	**2024**	2023	% Change
Average Daily Production (1)						
Oil and condensate (bbls/d)	**473**	419	13	**320**	139	130
Other NGLs (bbls/d)	**29**	28	4	**34**	16	113
Oil and NGLs (bbls/d)	**502**	447	12	**354**	155	128
Natural gas (mcf/d)	**3,490**	2,858	22	**3,648**	1,624	125
Oil equivalent (boe/d)	**1,084**	923	17	**962**	426	126

(1) “Natural gas” refers to shale gas; “Oil and condensate” refers to condensate and tight oil combined; “Other NGLs” refers to butane, propane and ethane combined; “Oil and NGLs” refers to tight oil and NGLs combined; “Oil equivalent” refers to the total oil equivalent of shale gas, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent. Readers are referred to the “Product Types” section for a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, tight oil, and NGLs.

Daily production increased to 1,084 boe/d and 962 boe/d for the three months and year ended December 31, 2024, respectively, from 923 boe/d and 426 boe/d for the comparative periods in 2023. The increase in production was the result of oil produced during the testing phase of the successful drilling and completions program at Two Rivers East. Commercial production is expected to start with the completion of the facility in Q2 2025.

Coelacanth’s production profile for the fourth quarter of 2024 was consistent with the comparative quarter in 2023. The Q4 2024 weighting was 54% natural gas (Q4 2023 - 52%) and 46% oil and NGLs (Q4 2023 - 48%).

OIL AND NATURAL GAS SALES	Three Months Ended December 31			Year Ended December 31		
($000s)	**2024**	2023	% Change	**2024**	2023	% Change
Oil and condensate	**3,791**	3,367	13	**10,465**	4,538	131
Other NGLs	**88**	85	4	**419**	192	118
Oil and NGLs	**3,879**	3,452	12	**10,884**	4,730	130
Natural gas	**665**	752	(12)	**2,852**	1,933	48
Total	**4,544**	4,204	8	**13,736**	6,663	106
Average Sales Price						
Oil and condensate ($/bbl)	**87.06**	87.38	(-)	**89.46**	88.94	1
Other NGLs ($/bbl)	**33.28**	32.32	3	**33.22**	33.22	-
Oil and NGLs ($/bbl)	**83.97**	83.88	-	**83.99**	83.28	1
Natural gas production sales and transportation revenue ($/mcf)	**2.07**	2.86	(28)	**2.14**	3.26	(34)
Combined ($/boe)	**45.57**	49.47	(8)	**39.01**	42.82	(9)

Revenue totaled $4.5 million and $13.7 million for the three months and year ended December 31, 2024, respectively, compared to $4.2 million and $6.7 million for the comparative periods in 2023. The large increase in revenue for the year ended December 31, 2024 compared to 2023 was mainly the result of a large increase in production resulting from the successful drilling at Two Rivers West which was partially offset by a decline in natural gas pricing.

The following table outlines the Company’s realized wellhead prices and industry benchmarks:

Commodity Pricing	Three Months Ended December 31			Year Ended December 31		
	2024	2023	% Change	**2024**	2023	% Change
Oil and NGLs						
Corporate price ($CDN/bbl)	**83.97**	83.88	-	**83.99**	83.28	1
Canadian light sweet ($CDN/bbl)	**92.69**	97.55	(5)	**98.13**	99.87	(2)
West Texas Intermediate ("WTI") ($US/bbl)	**70.27**	78.32	(10)	**75.73**	77.63	(2)
Natural gas						
Corporate price ($CDN/mcf)	**2.07**	2.86	(28)	**2.14**	3.26	(34)
AECO price ($CDN/mcf)	**1.48**	2.30	(36)	**1.39**	2.64	(47)
Westcoast Station 2 ($CDN/mcf)	**0.95**	2.04	(53)	**1.09**	2.23	(51)
Chicago City Gate ($US/mmbtu)	**2.51**	2.30	9	**2.19**	2.32	(6)
Exchange rate						
CDN/US dollar exchange rate	**0.7147**	0.7349	(3)	**0.7301**	0.7413	(2)

Differences between corporate and benchmark prices can be the result of quality differences (higher or lower API oil and higher or lower heat content natural gas), sour content, the mix of sales points and marketing contracts negotiated for products, the mix of oil and NGLs, and various other factors. Coelacanth's differences are mainly the result of higher heat content natural gas production that is priced higher than AECO reference prices as well as the diversification of sales points and marketing contracts for products.

The Company's corporate average oil and NGLs prices were 90.6% and 85.6% of Canadian light sweet prices for the three months and year ended December 31, 2024, respectively, consistent with 86.0% and 83.4% for the comparative periods in 2023. Coelacanth's liquids mix during the fourth quarter of 2024 was approximately 94% light oil, condensate and pentanes, 3% butane and 3% propane (Q4 2023 - 94% light oil, condensate and pentanes, 3% butane and 3% propane).

Corporate average natural gas prices were 58.9% and 71.3% of Chicago City Gate price (converted to Canadian dollars) for the three months and year ended December 31, 2024, respectively, compared to 91.4% and 104.2% for the comparative periods in 2023. The decrease was due to a higher percentage of the Company's natural gas production being sold under lower priced Westcoast Station 2 contracts than Chicago contracts. The Company has contracted 1.5 mmcf/d of natural gas to be delivered to Chicago with the remainder being delivered to Westcoast Station 2.

Future prices received from the sale of the products may fluctuate as a result of market factors. In addition, the Company may enter into commodity price contracts to help manage future cash flows. The Company does not currently have any commodity price contracts outstanding.

ROYALTIES	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2024**	2023	% Change	**2024**	2023	% Change
Oil and NGLs	**779**	797	(2)	**2,424**	1,149	111
Natural gas	**41**	69	(41)	**274**	340	(19)
Total	**820**	866	(5)	**2,698**	1,489	81
Average Royalty Rate (% of sales)						
Oil and NGLs	**20.1**	23.1	(13)	**22.3**	24.3	(8)
Natural gas	**6.2**	9.2	(33)	**9.6**	17.6	(45)
Combined	**18.0**	20.6	(13)	**19.6**	22.3	(12)

The Company pays royalties to provincial governments (Crown) and other oil and gas companies that own surface or mineral rights. Crown royalties are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to commodity price fluctuations and changes in production volumes on a well-by-well basis, subject to a minimum and maximum rate restriction ascribed by the Crown.

Royalties totaled $0.8 million and $2.7 million for the three months and year ended December 31, 2024, respectively, compared to $0.9 million and $1.5 million for the comparative periods in 2023. For the year ended December 31, 2024, the increase in royalties was mainly as a result of the significant growth in production and revenue at Two Rivers West. Royalty rates declined as the result of a decrease in natural gas commodity prices and the new wells at Two Rivers West having less royalty burdens than the legacy production.

OPERATING EXPENSES	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2024**	2023	% Change	**2024**	2023	% Change
Oil and NGLs	**385**	476	(19)	**1,227**	753	63
Natural gas	**401**	337	19	**2,108**	1,309	61
Operating expenses	**786**	813	(3)	**3,335**	2,062	62
Average operating expenses						
Oil and NGLs ($/bbl)	**8.34**	11.57	(28)	**9.47**	13.25	(29)
Natural gas ($/mcf)	**1.25**	1.28	(2)	**1.58**	2.21	(29)
Combined ($/boe)	**7.88**	9.57	(18)	**9.47**	13.25	(29)

Per unit operating expenses were $7.88/boe and $9.47/boe for the three months and year ended December 31, 2024, respectively, down from $9.57/boe and $13.25/boe in the comparative periods in 2023. The decrease is mainly the result of increased production, thus spreading fixed costs over more production volumes.

NET TRANSPORTATION EXPENSES	Three Months Ended December 31			Year Ended December 31		
($000s)	**2024**	2023	% Change	**2024**	2023	% Change
Oil and NGLs	**256**	204	25	**448**	233	92
Natural gas	**244**	214	14	**974**	662	47
Net transportation expenses (non-GAAP)	**500**	418	20	**1,422**	895	59
Unutilized transportation	**387**	262	48	**1,891**	1,035	83
Transportation expenses	**887**	680	30	**3,313**	1,930	72
Average transportation expenses						
Oil and NGLs ($/bbl)	**5.54**	4.95	12	**3.46**	4.10	(16)
Natural gas ($/mcf)	**0.76**	0.81	(6)	**0.73**	1.12	(35)
Net transportation expenses ($/boe)	**5.01**	4.92	2	**4.04**	5.75	(30)
Unutilized transportation ($/boe)	**3.88**	3.08	26	**5.37**	6.65	(19)
Transportation expenses ($/boe)	**8.89**	8.00	11	**9.41**	12.40	(24)

Net transportation expenses (see “Non-GAAP and Other Financial Measures”) are mainly third-party pipeline tariffs from firm transportation agreements to deliver production to the purchasers at main hubs.

Transportation expenses increased to $0.9 million and $3.3 million for the three months and year ended December 31, 2024, respectively, compared to $0.7 million and $1.9 million for the comparative periods in 2023 mainly as the result of increased production and transportation commitments.

Net transportation expenses remained consistent on a per boe basis during the three months ended December 31, 2024 compared to the same period in 2023. Net transportation expenses decreased on a per boe basis to $4.04/boe for the year ended December 31, 2024 compared to $5.75/boe for the comparative period in 2023. The decrease mainly related to natural gas and was the result of production exceeding 1.5 mmcf/d (portion being delivered to Chicago with a higher transportation expense) and thus a higher percentage of natural gas sales in 2024 being sold under Westcoast Station 2 contracts instead of Chicago. While the sales prices were higher on Chicago contracts than on Westcoast Station 2 contracts, the transportation expenses are also higher.

Unutilized transportation is the portion of firm transportation agreements that the Company has committed to (less what has been assigned to other producers) that exceeds what the Company actually transported through pipelines for its produced natural gas volumes. Refer to the “Contractual Obligations” section for more information related to firm transportation agreements. The Company actively manages its firm transportation commitments and has been successful in mitigating a large portion of its 75.0 mmcf/d commitment to deliver natural gas to Westcoast Station 2. The Company has mitigated and reduced its Westcoast Station 2 commitment to approximately 30.6 mmcf/d for January 1, 2025 through December 31, 2025.

OPERATING NETBACK	Three Months Ended December 31			Year Ended December 31		
	2024	2023	% Change	**2024**	2023	% Change
Oil and NGLs ($/bbl)						
Revenue	**83.97**	83.88	-	**83.99**	83.28	1
Royalties	**(16.86)**	(19.38)	(13)	**(18.70)**	(20.24)	(8)
Operating expenses	**(8.34)**	(11.57)	(28)	**(9.47)**	(13.25)	(29)
Net transportation expenses (non-GAAP)	**(5.54)**	(4.95)	12	**(3.46)**	(4.10)	(16)
Operating netback (non-GAAP)	**53.23**	47.98	11	**52.36**	45.69	15
Natural gas ($/mcf)						
Revenue	**2.07**	2.86	(28)	**2.14**	3.26	(34)
Royalties	**(0.13)**	(0.26)	(50)	**(0.21)**	(0.57)	(63)
Operating expenses	**(1.25)**	(1.28)	(2)	**(1.58)**	(2.21)	(29)
Net transportation expenses (non-GAAP)	**(0.76)**	(0.81)	(6)	**(0.73)**	(1.12)	(35)
Operating netback (loss) (non-GAAP)	**(0.07)**	0.51	(114)	**(0.38)**	(0.64)	(41)
Combined ($/boe)						
Revenue	**45.57**	49.47	(8)	**39.01**	42.82	(9)
Royalties	**(8.22)**	(10.20)	(19)	**(7.66)**	(9.57)	(20)
Operating expenses	**(7.88)**	(9.57)	(18)	**(9.47)**	(13.25)	(29)
Net transportation expenses (non-GAAP)	**(5.01)**	(4.92)	2	**(4.04)**	(5.75)	(30)
Operating netback (non-GAAP)	**24.46**	24.78	(1)	**17.84**	14.25	25

During the three months and year ended December 31, 2024, Coelacanth generated an operating netback (see “Non-GAAP and Other Financial Measures”) of $24.46/boe and $17.84/boe, respectively, compared to $24.78/boe and $14.25/boe for the comparative periods in 2023. The increase for the year ended December 31, 2024 compared to 2023 was mainly the result of new wells at Two Rivers West which were less burdened by royalties than legacy production, had reduced operating expenses per unit as facility fixed costs were spread over increased production volumes, and had lower net transportation expenses as a larger portion of its production was sold under Westcoast Station 2 contracts which have lower transportation expenses due to proximity.

The following is a reconciliation of operating netback per boe to net loss per boe for the periods noted:

	Three Months Ended December 31			Year Ended December 31		
($/boe)	**2024**	2023	% Change	**2024**	2023	% Change
Operating netback	**24.46**	24.78	(1)	**17.84**	14.25	25
Depletion and depreciation	**(10.76)**	(12.18)	(12)	**(13.59)**	(14.93)	(9)
General and administrative expenses	**(15.46)**	(10.77)	44	**(14.34)**	(27.08)	(47)
Share based compensation	**(7.08)**	(16.31)	(57)	**(11.12)**	(23.49)	(53)
Loss on lease termination	**(2.02)**	-	100	**(0.57)**	-	100
Finance expense	**(18.02)**	(1.28)	1,308	**(6.33)**	(3.09)	105
Finance income	**3.65**	10.01	(64)	**8.23**	18.75	(56)
Unutilized transportation	**(3.88)**	(3.08)	26	**(5.37)**	(6.65)	(19)
Net loss	**(29.11)**	(8.83)	230	**(25.25)**	(42.24)	(40)

The following is a reconciliation of operating netback to net loss for the periods noted:

	Three Months Ended December 31			Year Ended December 31		
($/boe)	**2024**	2023	% Change	**2024**	2023	% Change
Operating netback	**2,438**	2,107	16	**6,281**	2,217	183
Depletion and depreciation	**(1,073)**	(1,035)	4	**(4,786)**	(2,323)	106
General and administrative expenses	**(1,540)**	(915)	68	**(5,049)**	(4,213)	20
Share based compensation	**(706)**	(1,386)	(49)	**(3,917)**	(3,654)	7
Loss on lease termination	**(201)**	-	100	**(201)**	-	100
Finance expense	**(1,797)**	(109)	1,549	**(2,230)**	(481)	364
Finance income	**363**	850	(57)	**2,896**	2,916	(1)
Unutilized transportation	**(387)**	(262)	48	**(1,891)**	(1,035)	83
Net loss	**(2,903)**	(750)	287	**(8,897)**	(6,573)	35

DEPLETION AND DEPRECIATION	Three Months Ended December 31			Year Ended December 31		
	2024	2023	% Change	**2024**	2023	% Change
Depletion and depreciation ($000s)	**1,073**	1,035	4	**4,786**	2,323	106
Depletion and depreciation ($/boe)	**10.76**	12.18	(12)	**13.59**	14.93	(9)

The Company calculates depletion on development and production assets included in property, plant, and equipment ("PP&E") based on proved and probable oil and natural gas reserves. Depletion and depreciation expense for the three months and year ended December 31, 2024 increased to $1.1 million and $4.8 million, respectively, from $1.0 million and $2.3 million for the comparative periods in 2023 as a result of increased production. On a per boe basis, depletion and depreciation for the three months and year ended December 31, 2024 was $10.76/boe and $13.59/boe, respectively, consistent with $12.18/boe and $14.93/boe for the comparative periods in 2023.

Included in depletion and depreciation expense for the three months and year ended December 31, 2024, is $50 thousand (December 31, 2023 - $0.1 million) and $0.4 million (December 31, 2023 - $0.4 million), respectively, related to the right-of-use assets for the Company's head office lease and field equipment.

IMPAIRMENT OF PROPERTY, PLANT, AND EQUIPMENT AND EXPLORATION AND EVALUATION ASSETS

At December 31, 2024 and December 31, 2023, the Company evaluated its PP&E Two Rivers CGU for indicators of impairment or impairment reversal and as a result of this assessment management determined that an impairment test was not required to be performed.

At December 31, 2024 and December 31, 2023, the Company evaluated its exploration and evaluation assets for indicators of impairment and as a result of this assessment management determined that an impairment test was not required to be performed.

GENERAL AND ADMINISTRATIVE	Three Months Ended December 31			Year Ended December 31		
($000s)	**2024**	2023	% Change	**2024**	2023	% Change
G&A expenses (gross)	**2,160**	1,351	60	**5,964**	5,129	16
G&A capitalized	**(620)**	(436)	42	**(915)**	(916)	(-)
G&A expenses (net)	**1,540**	915	68	**5,049**	4,213	20
G&A expenses ($/boe)	**15.46**	10.77	44	**14.34**	27.08	(47)

Net general and administrative expenses ("G&A") increased to $1.5 million and $5.0 million for the three months and year ended December 31, 2024, respectively, from $0.9 million and $4.2 million for the comparative periods in 2023 due to higher employment costs.

On a per unit basis G&A decreased to $14.34/boe for the year ended December 31, 2024, compared to $27.08/boe for the comparative period in 2023 due to the increase in production. For the three months ended December 31, 2024, per unit G&A costs increased to $15.46/boe from $10.77/boe mainly due to higher employment costs.

SHARE BASED COMPENSATION	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2024**	2023	% Change	**2024**	2023	% Change
Share based compensation (gross)	**816**	1,589	(49)	**4,695**	4,642	1
Share based compensation (capitalized)	**(110)**	(203)	(46)	**(778)**	(988)	(21)
Share based compensation (net)	**706**	1,386	(49)	**3,917**	3,654	7
Share based compensation ($/boe)	**7.08**	16.31	(57)	**11.12**	23.49	(53)

The Company accounts for its share based compensation plans using the fair value method. Under this method, compensation cost is charged to earnings over the vesting period for stock options and RSUs granted to officers, directors, employees, and consultants with a corresponding increase to contributed surplus.

Share based compensation expense totaled $0.7 million and $3.9 million for the three months and year ended December 31, 2024, respectively, compared to $1.4 million and $3.7 million for the comparative periods in 2023. The large decrease for Q4 2024 from Q4 2023 stems from a charge of $0.8 million in Q4 2023 equal to the difference between the fair value of the Private Placement Units received and the price paid for the Private Placement Units issued to certain officers and employees of the Company.

FINANCE EXPENSE	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2024**	2023	% Change	**2024**	2023	% Change
Interest expense	**371**	3	12,267	**533**	114	368
Lease interest expense	**9**	27	(67)	**77**	104	(26)
Financing obligation payable	**1,350**	-	100	**1,350**	-	100
Accretion of decommissioning obligations	**67**	79	(15)	**270**	263	3
Finance expense	**1,797**	109	1,549	**2,230**	481	364
Finance expense ($/boe)	**18.02**	1.28	1,308	**6.33**	3.09	105

Accretion expense was consistent for the three months and year ended December 31, 2024 compared to the same periods in 2023. Interest expense relates to standby fees on the credit facilities and interest expense on outstanding letters of guarantee for firm transportation agreements. Financing obligation payable relates to the non-refundable third party fees to secure the initial one-year term of the $45.0 million credit facility (refer to the "Liquidity and Capital Resources" section).

FINANCE INCOME

Finance income relates to interest earned on cash in the bank. Finance income totaled $0.4 million and $2.9 million for the three months and year ended December 31, 2024, respectively, compared to $0.8 million and $2.9 million for the comparative periods in 2023. The decrease in Q4 2024 from Q4 2023 corresponds to the decrease in the Company's cash balance over the comparative periods due to capital expenditures in Q4 2024.

DEFERRED INCOME TAXES

The Company has not realized the net deferred income tax asset due to a history of losses and it is not probable that future taxable profits, based on the estimated cash flows derived from the independently evaluated reserve report, would be sufficient to realize the deferred income tax asset at this time.

Estimated tax pools at December 31, 2024 total approximately $264.9 million (December 31, 2023 - $177.6 million).

CASH FLOW FROM (USED IN) OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW (USED)

The following is a reconciliation of cash flow from (used in) operating activities to adjusted funds flow (used) for the periods noted:

	Three Months Ended December 31			**Year Ended December 31**		
($000s)	**2024**	2023	% Change	**2024**	2023	% Change
Cash flow from (used in) operating activities	**3,157**	(404)	(881)	**2,203**	(4,234)	(152)
Add (deduct):						
Decommissioning expenditures	**161**	206	(22)	**1,427**	1,883	(24)
Change in restricted cash deposits	**(5,361)**	-	100	**(2,376)**	(784)	203
Change in non-cash working capital	**2,425**	1,948	24	**261**	2,802	(91)
Adjusted funds flow (used) (non-GAAP)	**382**	1,750	(78)	**1,515**	(333)	(555)

Adjusted funds flow (see “Non-GAAP and Other Financial Measures”) was $0.4 million ($nil per basic and diluted share) and $1.5 million ($nil per basic and diluted share) for the three months and year ended December 31, 2024, respectively, compared to adjusted funds flow of $1.8 million ($nil per basic and diluted share) and adjusted funds used of $0.3 million ($nil per basic and diluted share) for the comparative periods in 2023. The decrease in Q4 2024 from Q4 2023 was the result of $1.7 million of third party fees to secure the initial one-year term of the $45.0 million credit facility (refer to the “Liquidity and Capital Resources” section).

Cash flow from operating activities for the three months and year ended December 31, 2024 was $3.2 million ($0.01 per basic and diluted share) and $2.2 million ($nil per basic and diluted share), respectively, compared to cash flow used in operating activities of $0.4 million ($nil per basic and diluted share) and $4.2 million ($0.01 per basic and diluted share) for the comparative periods in 2023. Cash flow from (used in) operating activities differs from adjusted funds flow (used) due to the inclusion of changes in non-cash working capital, movements in restricted cash deposits and expenditures on decommissioning obligations. Cash flow from operating activities increased in 2024 as a result of the Company moving $5.4 million of restricted cash deposits in Q4 2024 to cash as its letter of guarantee requirements for decommissioning obligations have decreased commensurate with decommissioning expenditures and the Company’s credit facility replacing a portion of its restricted GIC’s.

NET LOSS

The Company incurred net losses of $2.9 million ($0.01 per basic and diluted share) and $8.9 million ($0.02 per basic and diluted share) for the three months and year ended December 31, 2024, respectively, compared to $0.8 million ($nil per basic and diluted share) and $6.6 million ($0.01 per basic and diluted share) for the comparative periods in 2023. The increase in 2024 was mainly the result of incurring $1.7 million of third party fees to secure the initial one-year term of the $45.0 million credit facility and increased depletion and depreciation expense resulting from increased production.

CAPITAL EXPENDITURES	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2024**	2023	% Change	**2024**	2023	% Change
Land	**220**	176	25	**765**	1,006	(24)
Drilling, completions, and workovers	**29,273**	30,602	(4)	**38,353**	61,274	(37)
Equipment	**35,152**	3,836	816	**44,935**	12,094	272
Geological and geophysical	**307**	42	631	**444**	191	132
Office furniture and equipment	**-**	-	-	**-**	48	(100)
Total expenditures	**64,952**	34,656	87	**84,497**	74,613	13

During the year ended December 31, 2024, the Company continued with facility procurement at Two Rivers East and related gathering and transport pipelines. The Company drilled and completed three Lower Montney wells and completed the previously drilled Basal Montney well at Two Rivers East on the existing 5-19 pad. The Company also negotiated a reduction in royalties on certain lands in return for a royalty on additional lands.

During the year ended December 31, 2023, the Company continued its preliminary facility upgrades and drilled its second Upper Montney well at Two Rivers West and then completed both 10-08 pad wells with production commencing on September 30, 2023. The Company also drilled its initial five well pad at Two Rivers East in which four wells (three Lower Montney and one Basal Montney) were completed in Q4 2023.

Commercial production from the Two Rivers East 5-19 pad is expected to start with the completion of the facility in Q2 2025.

LIQUIDITY AND CAPITAL RESOURCES

Management uses adjusted working capital (deficiency) (see “Non-GAAP and Other Financial Measures”) as a measure to assess the Company’s financial position and is reconciled as follows:

($000s)	**December 31, 2024**	December 31, 2023	% Change
Current assets	**11,579**	87,616	(87)
Less:			
Current liabilities	**(37,234)**	(28,754)	29
Working capital (deficiency)	**(25,655)**	58,862	(144)
Add:			
Restricted cash deposits	**4,900**	6,784	(28)
Current portion of decommissioning obligations	**2,118**	1,943	9
Adjusted working capital (deficiency) (Capital management measure)	**(18,637)**	67,589	(128)

At December 31, 2024, the Company had an adjusted working capital deficiency of $18.6 million.

On October 4, 2024, the Company secured two revolving bank credit facilities for a total of $52.0 million from a Canadian chartered bank. The credit facilities are backed by reserves at Two Rivers West plus a $45.0 million letter of credit from a third party. The commitment from the third party is for a two-year term. During the term, Coelacanth expects that the lending value of producing reserves at Two Rivers East will allow for the credit facility to be renegotiated and the letter of credit to be returned.

The first credit facility is a $7.0 million revolving operating demand loan credit facility that bears interest at prime plus 3.0%. The undrawn portion of the credit facility is subject to a standby fee of 1.0%. Any outstanding letters of guarantee reduce the amount that can be borrowed under the credit facility and bear interest at 4.0%. During the year ended December 31, 2024, the Company redeemed $5.4 million of restricted cash deposit GIC's and issued letters of guarantee for the same amount under the revolving operating demand loan credit facility thereby reducing the amount available from $7.0 million to $1.6 million.

The second credit facility is a $45.0 million revolving operating demand loan that bears interest at prime plus 0.25%. The undrawn portion of the credit facility is subject to a standby fee of 0.125%. This credit facility is secured by a $45.0 million letter of credit from a third party. The letter of credit fee is 3.0% of the total $45.0 million face value of the letter of credit whether drawn or not for the first one-year term plus the period prior to the start of the first term. The first term starts the earlier of when drawn or December 31, 2024. The Company has the option to extend the term by an additional maximum one-year term for a fee of 6% of the drawn portion of the letter of credit that can be reduced at any time by repayment of the credit facility.

The credit facilities and letter of credit are secured by a $75.0 million fixed and floating charge debenture on the assets of the Company. The next review of the credit facilities by the bank is scheduled on or before June 30, 2025.

As at December 31, 2024, no amounts were drawn under either credit facility.

The credit facilities include a covenant requiring the Company to maintain an adjusted working capital ratio of not less than one-to-one. The adjusted working capital ratio, as defined by its creditor, is calculated as current assets plus any undrawn amounts available on its demand loan credit facilities less current liabilities excluding any current portion drawn on the demand loan credit facilities. The definition of current assets and current liabilities excludes the fair value of risk management contracts. The Company was compliant with this covenant at December 31, 2024.

Subsequent to December 31, 2024, the Company received $22.7 million from a midstream company to finance a pipeline connecting Coelacanth facilities to the midstream company's gathering system. The Company is required to repay the principal amount over a five-year period at an effective interest rate of 12.0%.

On November 15, 2023, the Company closed a bought-deal public financing through a syndicate of underwriters. The Company issued 100.0 million units of the Company ("Units") at a price of $0.80 per Unit for gross proceeds of $80.0 million. A Unit is comprised of one common share of the Company and 0.33 common share purchase warrants. Each whole common share purchase warrant entitles the holder to purchase one common share at an exercise price of $1.05 per common share expiring on November 15, 2024. During Q4 2024, the warrant expiry date was extended to June 30, 2025.

On November 16, 2023, the Company closed a non-brokered private placement to three employees of 1,875,000 units of the Company ("Private Placement Units"), at a price of $0.80 per Private Placement Unit, for aggregate proceeds of $1.5 million. Each Private Placement Unit consists of one common share of the Company and one common share purchase warrant. Each common share purchase warrant entitles the holder to purchase one common share of the Company at a price of $0.80 per share expiring on November 16, 2028.

Management anticipates that the Company will continue to have adequate liquidity to fund budgeted capital investments through a combination of its cash balance, cash flow, equity, and debt if required. Coelacanth's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

CONTRACTUAL OBLIGATIONS

The following is a summary of the Company's contractual obligations and commitments at December 31, 2024:

($000s)	Total	Less than One Year	One to Three Years	After Three Years
Accounts payable and accrued liabilities	33,963	33,963	-	-
Lease obligations	354	110	244	-
Financing obligation payable	1,238	1,238	-	-
Decommissioning obligations	9,649	2,118	465	7,066
Operating commitments	566	194	372	-
Firm transportation agreements	173,500	4,050	12,970	156,480
Firm processing agreements	96,255	3,212	17,646	75,397
Property, plant, and equipment	10,056	10,056	-	-
Total contractual obligations	325,581	54,941	31,697	238,943

Operating commitments include the non-lease variable components (operating expenses) of the head office lease.

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has the following firm transportation commitments:

- 1.5 mmcf/d to deliver natural gas to the Alliance Trading Pool (ATP) and then to Chicago through October 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from January 1, 2023 through July 31, 2038.
- 50.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through May 31, 2038.
- 15.0 mmcf/d to deliver natural gas to Westcoast Station 2 from May 1, 2024 through April 30, 2055.
- 25.0 mmcf/d to deliver natural gas to Westcoast Station 2 from August 1, 2028 through July 31, 2043.

The Company assigned the following contracts to third parties, thus reducing its commitment:

- 4.4 mmcf/d to deliver natural gas to Westcoast Station 2 from April 1, 2023 through March 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through December 31, 2027.
- 20.0 mmcf/d to deliver natural gas to Westcoast Station 2 from October 1, 2023 through October 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from November 1, 2024 through December 31, 2025.

The impact of the reduced commitments are reflected in the table above.

Firm processing agreements include 30.0 mmcf/d of processing services at a gas processing facility for a period of 10 years. This is expandable by any volume up to an additional 30.0 mmcf/d (60.0 mmcf/d total) at the election of the Company at any date up to July 1, 2025 for the remainder of the original term. As part of the arrangement, the midstream company has agreed to fund the extension of their gathering system to certain contractual thresholds pending the achievement of certain project milestones. Subsequent to December 31, 2024, the Company received $22.7 million from the midstream company. The Company is required to repay the principal amount over a five-year period at an effective interest rate of 12.0%.

OFF BALANCE SHEET ARRANGEMENTS

The Company has certain lease arrangements, all of which are reflected in the contractual obligations and commitments table, which were entered into in the normal course of operations. All leases other than the fixed payment component of the head office lease have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease.

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares, Class A preferred shares, issuable in series, Class B preferred shares, issuable in series, and Class C preferred shares, issuable in series. The voting common shares of the Company commenced trading on the TSXV on June 20, 2022 under the symbol “CEI”. The following table summarizes the common shares outstanding and the number of shares exercisable into common shares from options, warrants, and other instruments:

(000s)	**December 31, 2024**	April 23, 2025
Voting common shares	**530,670**	531,386
Warrants	**62,710**	62,710
Stock options	**16,971**	22,354
Restricted share units	**5,579**	8,427
Total	**615,930**	624,877

Subsequent to December 31, 2024, the Company granted 5.7 million stock options at an average exercise price of $0.81 per common share expiring five years from the date of grant and vest one-third on each of the first, second and third anniversaries of the date of grant. The Company also granted 3.6 million RSUs vesting one-third on each of the first, second and third anniversaries of the date of grant.

SUMMARY OF QUARTERLY RESULTS

	Q4 2024	Q3 2024	Q2 2024	Q1 2024	Q4 2023	Q3 2023	Q2 2023	Q1 2023
Average Daily Production								
Oil and NGLs (bbls/d)	**502**	254	323	337	447	46	67	60
Natural gas (mcf/d)	**3,490**	3,450	3,724	3,934	2,858	929	1,321	1,380
Oil equivalent (boe/d)	**1,084**	829	944	993	923	201	287	290
($000s, except per share amounts)								
Oil and natural gas sales	**4,544**	2,362	3,164	3,666	4,204	679	826	954
Cash flow from (used in)								
operating activities	**3,157**	(3,730)	(480)	3,256	(404)	(2,553)	765	(2,042)
Per share basic and diluted (2)	**0.01**	(0.01)	(-)	0.01	(-)	(0.01)	(-)	(-)
Adjusted funds flow (used) (1)	**382**	(207)	262	1,078	1,750	(773)	(756)	(554)
Per share basic and diluted	**-**	(-)	-	-	-	(-)	(-)	(-)
Net loss	**(2,903)**	(2,464)	(2,329)	(1,201)	(750)	(1,869)	(2,165)	(1,789)
Per share basic and diluted	**(0.01)**	(-)	(-)	(-)	(-)	(-)	(0.01)	(-)

(1) Adjusted funds flow (used) and adjusted funds flow (used) per share do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the “Non-GAAP and Other Financial Measures” section for more details and the “Cash Flow From (Used in) Operating Activities and Adjusted Funds Flow (Used)” section for a reconciliation from cash flow from (used in) operating activities.

(2) Supplemental financial measure. Please refer to the “Non-GAAP and Other Financial Measures” section for more details.

The Company experienced normal production declines on the Two Rivers property from Q1 2023 to Q3 2023. The increase in production, oil and natural gas sales, cash flow from operating activities, and adjusted funds flow between Q4 2023 and Q4 2024 stems from two new wells at Two Rivers West coming on-stream in Q4 2023 and the testing of new wells at Two Rivers East during Q4 2024. Oil and natural gas sales, cash flow from (used in) operating activities and adjusted funds flow (used) generally followed the same trend as production with some exceptions based on volatility of commodity prices received.

MATERIAL ACCOUNTING POLICIES

All accounting policies are consistent with those of the previous financial year, except as noted below. Refer to note 3 of the audited financial statements for the year ended December 31, 2024 for the Company's material accounting policies.

IAS 1 *Presentation of Financial Statements* was amended in January 2020 and October 2022 by the IASB to clarify the presentation requirements of liabilities as either current or non-current within the statement of financial position. The amendments apply retrospectively for annual reporting periods beginning on or after January 1, 2024. The Company adopted these amendments effective January 1, 2024 and the adoption did not have an impact on the Company's financial statements.

FUTURE ACCOUNTING PRONOUNCEMENTS

IFRS 18 *Presentation and Disclosure in Financial Statements* was issued by the IASB in April 2024. IFRS 18 introduces defined categories for income and expenses and certain defined subtotals in the statement of operations and comprehensive income (loss), required disclosures of certain management-defined performance measures, and aggregation and disaggregation principles for the grouping of information in the financial statements. IFRS 18 will replace IAS 1 and is effective for annual periods beginning on or after January 1, 2027. The standard requires retrospective application with early adoption permitted. The Company is currently evaluating the impact of adopting IFRS 18 on the financial statements.

In May 2024, the IASB issued amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* regarding the settlement of financial liabilities via electronic payment systems and the assessment of contractual cash flow characteristics of financial assets. The amendments are effective for annual periods beginning on or after January 1, 2026, and require retrospective application with early adoption permitted. The Company is currently evaluating the impact of adoption on its financial statements.

CRITICAL ACCOUNTING ESTIMATES

Management is required to make estimates, judgments, and assumptions in the application of IFRS that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended. Certain of these estimates may change from period to period resulting in a material impact on the Company's results from operations and financial position (see note 2d in the notes to the Company's December 31, 2024 financial statements for full descriptions of the use of estimates and judgments).

RISK ASSESSMENT

The acquisition, exploration, and development of oil and natural gas properties involves many risks common to all participants in the oil and natural gas industry. Coelacanth's exploration and development activities are subject to various business risks such as unstable commodity prices, interest rate and foreign exchange rate fluctuations, the uncertainty of replacing production and reserves on an economic basis, government regulations including implementation of new, or expansion of existing, tariffs on exported and/or imported products, taxes, and safety and environmental concerns. While management realizes these risks cannot be eliminated, they are committed to monitoring and mitigating these risks.

Reserves and reserve replacement

The recovery and reserve estimates on Coelacanth's properties are estimates only and the actual reserves may be materially different from that estimated. The estimates of reserve values are based on a number of variables including: forecasted oil and natural gas commodity prices, forecasted production, forecasted operating costs, forecasted royalty costs and forecasted future development costs. All of these factors may cause estimates to vary from actual results.

Coelacanth's future oil and natural gas reserves, production, and adjusted funds flow to be derived therefrom are highly dependent on the Company successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Coelacanth's reserves will depend on its ability to acquire suitable prospects or properties and discover new reserves.

To mitigate this risk, Coelacanth has assembled a team of experienced technical professionals who have expertise operating and exploring in areas the Company has identified as being the most prospective for increasing reserves on an economic basis. To further mitigate reserve replacement risk, Coelacanth has targeted a majority of its prospects in areas which have multi-zone potential, year-round access, and lower drilling costs and employs advanced geological and geophysical techniques to increase the likelihood of finding additional reserves.

Operational risks

Coelacanth's operations are subject to the risks normally incidental to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells. Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property.

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk, and other price risk, such as commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns. The Company may use financial derivatives or physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Foreign exchange risk
The prices received by the Company for the production of oil, natural gas, and NGLs are primarily determined in reference to US dollars, but are settled with the Company in Canadian dollars. The Company's cash flow from commodity sales will therefore be impacted by fluctuations in foreign exchange rates. The Company currently does not have any foreign exchange contracts in place.

Interest rate risk
The Company is exposed to interest rate risk on its cash, restricted cash deposit, and credit facility balances. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. The amount drawn on the Company's credit facilities at December 31, 2024 was $nil.

Commodity price risk
Oil and natural gas prices are impacted by not only the relationship between the Canadian and US dollar but also by world economic events that dictate the levels of supply and demand. The Company's oil, natural gas, and NGLs production is marketed and sold on the spot market to area aggregators based on daily spot prices that are adjusted for product quality and transportation costs. The Company's cash flow from product sales will therefore be impacted by fluctuations in commodity prices. In addition, the Company may enter into commodity price contracts to manage future cash flows. The Company does not currently have any commodity price contracts in place.

Credit risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial asset fail to meet or discharge their obligation to the Company. A substantial portion of the Company's accounts receivable are with customers and joint interest partners in the oil and natural gas industry and are subject to normal industry credit risks. The Company generally grants unsecured credit but routinely assesses the financial strength of its customers and joint interest partners.

The Company sells the majority of its production to three petroleum and natural gas marketers and therefore is subject to concentration risk. Historically, the Company has not experienced any collection issues with its oil and natural gas marketers. Joint interest receivables are typically collected within one to three months of the joint interest billing being issued to the partner. The Company attempts to mitigate the risk from joint interest receivables by obtaining partner approval for significant capital expenditures prior to the expenditure being incurred. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint interest partners; however, in certain circumstances, the Company may cash call a partner in advance of expenditures being incurred.

The maximum exposure to credit risk is represented by the carrying amount of cash, restricted cash deposits, and accounts receivable on the statement of financial position. At December 31, 2024, $4.1 million (87%) of the Company's outstanding accounts receivable were current and $0.6 million (13%) were outstanding for more than 90 days. During the year ended December 31, 2024, the Company deemed $35 thousand of outstanding accounts receivable to be uncollectable (December 31, 2023 - $44 thousand).

Cash and restricted cash deposits consist of bank balances placed with a financial institution with strong investment grade ratings which management believes the risk of loss to be remote. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade financial institution counterparties and by not entering into contracts for trading or speculative purposes.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk includes ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual, quarterly, and monthly capital expenditure budgets, which are monitored and updated as required, and requires authorizations for expenditures on projects to assist with the management of capital. In managing liquidity risk, the Company ensures that it has access to additional financing, including potential equity issuances and additional debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to insurable losses.

To facilitate its capital expenditure program, the Company has two revolving credit facilities (refer to the "Liquidity and Capital Resources" section). At December 31, 2024, the Company had an adjusted working capital deficiency of $18.6 million and no amounts were drawn under its credit facilities. Subsequent to December 31, 2024, the Company received $22.7 million from a midstream company to finance a pipeline connecting Coelacanth facilities to the midstream company's gathering system. This amount will be repaid over a five-year period at an effective interest rate of 12.0%. The proceeds from the midstream company, in addition to available lending capacity, will be used to fund the remaining forecasted capital of approximately $35.0 million to complete facility and infrastructure projects and commence operations at Two River East in the first half of 2025.

The Company forecasts that it will have sufficient lending capacity and operational cash flows to meet its current and future obligations, to make any scheduled credit facility and associated interest payments, and to fund the other needs of the business for at least the next 12 months. Coelacanth's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

Safety and Environmental Risks

The oil and natural gas business is subject to extensive regulation pursuant to various municipal, provincial, national, and international conventions and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, or emissions of various substances produced in association with oil and natural gas operations. Coelacanth is committed to meeting and exceeding its environmental and safety responsibilities. Coelacanth has implemented an environmental and safety policy that is designed, at a minimum, to comply with current governmental regulations set for the oil and natural gas industry. Changes to governmental regulations are monitored to ensure compliance. Environmental reviews are completed as part of the due diligence process when evaluating acquisitions. Environmental and safety updates are presented and discussed at each Board of Directors meeting. Coelacanth maintains adequate insurance commensurate with industry standards to cover reasonable risks and potential liabilities associated with its activities as well as insurance coverage for officers and directors executing their corporate duties. To the knowledge of management, there are no legal proceedings to which Coelacanth is a party or of which any of its property is the subject matter, nor are any such proceedings known to Coelacanth to be contemplated.

For additional information on the risks relating to the Company's business, see the "Risk Factors" section contained in the Company's annual information form for the year ended December 31, 2024, which is available on the SEDAR+ website at www.sedarplus.com.

PRODUCT TYPES

The Company uses the following references to sales volumes in the MD&A:

Natural gas refers to shale gas
Oil and condensate refers to condensate and tight oil combined
Other NGLs refers to butane, propane and ethane combined
Oil and NGLs refers to tight oil and NGLs combined
Oil equivalent refers to the total oil equivalent of shale gas, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent as described above.

The following is a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, tight oil, and NGLs:

Sales Volumes by Product Type	Q4 2024	Q3 2024	Q2 2024	Q1 2024	Q4 2023	Q3 2023	Q2 2023	Q1 2023
Condensate (bbls/d)	**22**	33	56	19	12	4	6	8
Other NGLs (bbls/d)	**29**	33	39	37	28	7	14	14
NGLs (bbls/d)	**51**	66	95	56	40	11	20	22
Tight oil (bbls/d)	**451**	188	228	281	407	35	47	38
Condensate (bbls/d)	**22**	33	56	19	12	4	6	8
Oil and condensate (bbls/d)	**473**	221	284	300	419	39	53	46
Other NGLs (bbls/d)	**29**	33	39	37	28	7	14	14
Oil and NGLs (bbls/d)	**502**	254	323	337	447	46	67	60
Shale gas (mcf/d)	**3,490**	3,450	3,724	3,934	2,858	929	1,321	1,380
Natural gas (mcf/d)	**3,490**	3,450	3,724	3,934	2,858	929	1,321	1,380
Oil equivalent (boe/d)	**1,084**	829	944	993	923	201	287	290

TEST RESULTS AND INITIAL PRODUCTION RATES

The 5-19 Lower Montney well was production tested for 9.4 days and produced at an average rate of 377 bbl/d oil and 2,202 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The A5-19 Basal Montney well was production tested for 5.9 days and produced at an average rate of 117 bbl/d oil and 630 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The B5-19 Upper Montney well was production tested for 6.3 days and produced at an average rate of 92 bbl/d oil and 2,100 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The C5-19 Lower Montney well was production tested for 5.8 days and produced at an average rate of 736 bbl/d oil and 2,660 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The D5-19 Lower Montney well was production tested for 12.6 days and produced at an average rate of 170 bbl/d oil and 580 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The E5-19 Lower Montney well was production tested for 11.4 days and produced at an average rate of 312 bbl/d oil and 890 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure was stable, and production was starting to decline.

The F5-19 Lower Montney well was production tested for 4.9 days and produced at an average rate of 728 bbl/d oil and 1,607 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The G5-19 Lower Montney well was production tested for 7.1 days and produced at an average rate of 415 bbl/d oil and 1,489 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure and production rates were stable.

The H5-19 Lower Montney well was production tested for 8.1 days and produced at an average rate of 411 bbl/d oil and 1,166 mcf/d gas (net of load fluid and energizing fluid) over that period which includes the initial cleanup where only load water was being recovered. At the end of the test, flowing wellhead pressure was stable and production was starting to decline.

A pressure transient analysis or well-test interpretation has not been carried out on these nine wells and thus certain of the test results provided herein should be considered to be preliminary until such analysis or interpretation has been completed. Test results and initial production rates disclosed herein, particularly those short in duration, may not necessarily be indicative of long-term performance or of ultimate recovery.

Any references to peak rates, test rates, IP30, IP90, IP180 or initial production rates or declines are useful for confirming the presence of hydrocarbons, however, such rates and declines are not determinative of the rates at which such wells will continue production and decline thereafter and are not indicative of long-term performance or ultimate recovery. IP30 is defined as an average production rate over 30 consecutive days, IP90 is defined as an average production rate over 90 consecutive days and IP180 is defined as an average production rate over 180 consecutive days. Readers are cautioned not to place reliance on such rates in calculating aggregate production for the Company.

FORWARD-LOOKING INFORMATION

This document contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words “expect”, “anticipate”, “continue”, “estimate”, “may”, “will”, “should”, “believe”, “intends”, “forecast”, “plans”, “guidance” and similar expressions are intended to identify forward-looking statements or information.

More particularly and without limitation, this MD&A contains forward-looking statements and information relating to the Company’s oil and condensate, other NGLs, and natural gas production, royalty rates, capital programs, and adjusted working capital (deficiency). The forward-looking statements and information are based on certain key expectations and assumptions made by the Company, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities, and the availability and cost of labour and services.

Although the Company believes that the expectations reflected in such forward-looking statements and information are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs, and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty, and environmental legislation. The forward-looking statements and information contained in this document are made as of the date hereof for the purpose of providing the readers with the Company’s expectations for the coming year. The forward-looking statements and information may not be appropriate for other purposes. The Company undertakes no obligation to update publicly or revise any forward-looking statements or information, whether as a result of new information, future events or otherwise, unless so required by applicable securities laws.

ADDITIONAL INFORMATION

In addition to the information disclosed in this MD&A, more detailed information related to the Company can be found on the SEDAR+ website at www.sedarplus.com.

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INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Coelacanth Energy Inc.

Opinion

We have audited the financial statements of Coelacanth Energy Inc. (the Entity), which comprise:

- the statements of financial position as at December 31, 2024 and December 31, 2023
- the statements of operations and comprehensive loss for the years then ended
- the statements of shareholders' equity for the years then ended
- the statements of cash flows for the years then ended
- and notes to the financial statements, including a summary of material accounting policy information

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

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Entity as at December 31, 2024 and December 31, 2023, and its financial performance and its cash flows for the years then ended in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board.

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 Entity 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.

Key Audit Matter

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2024. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

We have determined the matter described below to be the key audit matter to be communicated in our auditor's report.

Assessment of the impact of estimated proved and probable oil and natural gas reserves on property, plant, and equipment ("PP&E")

Description of the matter

We draw attention to note 2, note 3 and note 5 to the financial statements. The Entity uses estimated proved and probable oil and natural gas reserves to deplete its development and production assets included in PP&E, to assess for indicators of impairment or impairment reversal on its cash-generating unit ("CGU") and, if any such indicators exist, to perform an impairment test to estimate the recoverable amount of the CGU. The Entity has $42.4 million of PP&E as at December 31, 2024.

The Entity depletes its net carrying value of development and production assets using the unit of production method by reference to the ratio of production in the period to the related proved and probable oil and natural gas reserves, taking into account estimated forecasted future development costs necessary to bring those reserves into production. Depletion expense on development and production assets was $4.3 million for the year ended December 31, 2024.

The Entity assesses at each reporting date whether there is an indication that PP&E within the Entity's CGU may be impaired or that historical impairment may be reversed. The estimate of proved and probable oil and natural gas reserves is significant to the Entity's assessment. The Entity determined that there were no external or internal indicators of impairment or impairment reversal at December 31, 2024 for the Entity's CGU and no impairment test was required.

The estimate of proved and probable oil and natural gas reserves requires the expertise of independent third party reserve evaluators and includes significant assumptions related to:

- Forecasted oil and natural gas commodity prices
- Forecasted production
- Forecasted operating costs
- Forecasted royalty costs
- Forecasted future development costs.

The Entity engages independent third party reserve evaluators to estimate the proved and probable oil and natural gas reserves.

Why the matter is a key audit matter

We identified the assessment of the impact of estimated proved and probable oil and natural gas reserves on PP&E as a key audit matter. Significant auditor judgment was required to evaluate the results of our audit procedures regarding the estimate of proved and probable oil and natural gas reserves and the external and internal indicators of impairment or impairment reversal included in the Entity's indicator assessment.

How the matter was addressed in the audit

The following are the primary procedures we performed to address this key audit matter:

With respect to the estimate of proved and probable oil and natural gas reserves:

- We evaluated the competence, capabilities and objectivity of the independent third party reserve evaluators engaged by the Entity
- We compared forecasted oil and natural gas commodity prices to those published by other independent third party reserve evaluators
- We compared the 2024 actual production, operating costs, royalty costs and development costs of the Entity to those estimates used in the prior year's estimate of proved oil and natural gas reserves to assess the Entity's ability to accurately forecast
- We evaluated the appropriateness of forecasted production and forecasted operating costs, royalty costs and future development costs assumptions by comparing to 2024 historical results. We took into account changes in conditions and events affecting the Entity to assess the adjustments or lack of adjustments made by the Entity in arriving at the assumptions.

We assessed the depletion expense calculation for compliance with IFRS Accounting Standards as issued by the International Accounting Standards Board.

We evaluated the Entity's assessment of external and internal indicators of impairment or impairment reversal by considering whether the quantitative and qualitative information in the analysis was consistent with external market and industry data and the estimate of proved and probable oil and natural gas reserves.

Other Information

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.
- the information, other than the financial statements and the auditor's report thereon, included in the document entitled "2024 Annual Report".

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 indicators that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions and the information, other than the financial statements and the auditor's report thereon, included in the document entitled "2024 Annual Report" as at the date of this auditor's report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditor's report.

We have nothing to report in this regard.

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

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board, 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 Entity'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 Entity or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Entity'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 Entity’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 Entity’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 Entity to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.
- Determine, from the matters communicated with those charged with governance, those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor’s report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our auditor’s report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this auditor’s report is Jason Grodziski.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
April 23, 2025

Coelacanth Energy Inc.
Statements of Financial Position

($000s)	Note	**December 31 2024**	December 31 2023
Assets			
Current assets			
Cash		**5,693**	82,568
Current portion of restricted cash deposits	(4)	**-**	492
Accounts receivable		**4,730**	4,139
Prepaid expenses and deposits		**1,156**	417
		11,579	87,616
Restricted cash deposits	(4)	**4,900**	6,784
Property, plant, and equipment	(5)	**42,381**	45,711
Exploration and evaluation assets	(6)	**154,178**	68,883
		201,459	121,378
		213,038	208,994
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**33,768**	26,376
Current portion of lease obligations	(7)	**110**	435
Financing obligation payable	(8)	**1,238**	-
Current portion of decommissioning obligations	(9)	**2,118**	1,943
		37,234	28,754
Lease obligations	(7)	**244**	795
Decommissioning obligations	(9)	**7,531**	6,926
		45,009	36,475
Shareholders' Equity			
Shareholders' capital	(10)	**175,307**	173,918
Warrants	(10)	**6,979**	6,562
Contributed surplus		**7,137**	4,119
Deficit		**(21,394)**	(12,080)
		168,029	172,519
		213,038	208,994
Commitments	(22)		
Subsequent events	(11,22)		

The accompanying notes are an integral part of these financial statements.

Approved on behalf of the Board of Directors

Rob Zakresky
Director

Tom Medvedic
Director

Coelacanth Energy Inc.
Statements of Operations and Comprehensive Loss

($000s, except per share amounts)	Note	Years Ended December 31 2024	2023
Revenue			
Oil and natural gas sales	(21)	**13,736**	6,663
Royalties		**(2,698)**	(1,489)
		11,038	5,174
Expenses			
Operating		**3,335**	2,062
Transportation		**3,313**	1,930
Depletion and depreciation	(5,6)	**4,786**	2,323
General and administrative		**5,049**	4,213
Share based compensation	(11)	**3,917**	3,654
Loss on lease termination	(7)	**201**	-
Finance income		**(2,896)**	(2,916)
Finance expense	(14)	**2,230**	481
		19,935	11,747
Net loss and comprehensive loss		**(8,897)**	(6,573)
Net loss per share			
Basic and diluted	(12)	**(0.02)**	(0.01)

The accompanying notes are an integral part of these financial statements.

Coelacanth Energy Inc.
Statements of Shareholders' Equity

($000s)	Note	Share-holders' Capital	Warrants	Contributed Surplus	Deficit	Total Equity
Balance, December 31, 2022		97,259	4,272	1,053	(5,507)	97,077
Net loss		-	-	-	(6,573)	(6,573)
Issue of common shares and warrants (net of share issue costs)	(10)	75,751	2,334	-	-	78,085
Exercise of Warrants	(10)	119	(44)	-	-	75
Settlement of vested RSUs	(10)	789	-	(789)	-	-
Share based compensation	(11)	-	-	3,855	-	3,855
Balance, December 31, 2023		173,918	6,562	4,119	(12,080)	172,519
Net loss		**-**	**-**	**-**	**(8,897)**	**(8,897)**
Settlement of vested RSUs	(10)	**1,389**	**-**	**(1,389)**	**-**	**-**
Settlement of stock options and RSUs	(11)	**-**	**-**	**(288)**	**-**	**(288)**
Share based compensation	(11)	**-**	**-**	**4,695**	**-**	**4,695**
Warrant extension	(10)	**-**	**417**	**-**	**(417)**	**-**
Balance, December 31, 2024		**175,307**	**6,979**	**7,137**	**(21,394)**	**168,029**

The accompanying notes are an integral part of these financial statements.

Coelacanth Energy Inc.
Statements of Cash Flows

($000s)	Note	Years Ended December 31 2024	2023
Operating Activities			
Net loss		**(8,897)**	(6,573)
Depletion and depreciation	(5,6)	**4,786**	2,323
Share based compensation	(11)	**3,917**	3,654
Finance expense	(14)	**2,230**	481
Interest paid	(14)	**(610)**	(218)
Financing obligation payments	(8)	**(112)**	
Loss on lease termination	(7)	**201**	-
Decommissioning expenditures	(9)	**(1,427)**	(1,883)
Restricted cash deposits	(4)	**2,376**	784
Change in non-cash working capital	(20)	**(261)**	(2,802)
		2,203	(4,234)
Financing Activities			
Issue of common shares, flow-through common shares, and warrants	(10)	**-**	81,500
Share and warrant issue costs	(10)	**-**	(4,202)
Exercise of Warrants	(10)	**-**	75
Settlement of stock options and RSUs	(11)	**(288)**	-
Payment of lease obligations	(7)	**(616)**	(348)
Change in non-cash working capital	(20)	**(969)**	273
		(1,873)	77,298
Investing Activities			
Capital expenditures - property, plant, and equipment	(5)	**(1,206)**	(26,928)
Capital expenditures - exploration and evaluation assets	(6)	**(83,291)**	(47,685)
Change in non-cash working capital	(20)	**7,292**	18,707
		(77,205)	(55,906)
Change in cash		**(76,875)**	17,158
Cash, beginning of year		**82,568**	65,410
Cash, end of year		**5,693**	82,568

The accompanying notes are an integral part of these financial statements.

(Tabular amounts in 000s, unless otherwise stated)

1. REPORTING ENTITY

Coelacanth Energy Inc. ("Coelacanth" or the "Company") is an oil and natural gas company, actively engaged in the acquisition, development, exploration, and production of oil and natural gas reserves in northeastern British Columbia, Canada. Coelacanth was incorporated in Alberta, Canada under the Business Corporations Act (Alberta) on March 24, 2022 under the name of 2418573 Alberta Ltd., and subsequently changed its name to Coelacanth Energy Inc. on April 12, 2022. The Company commenced trading on the TSX Venture Exchange ("TSXV") on June 20, 2022 under the symbol "CEI". The Company's place of business is located at 2110, 530 - 8th Avenue SW, Calgary, Alberta, Canada, T2P 3S8.

2. BASIS OF PRESENTATION

(a) Statement of compliance

These financial statements have been prepared in accordance with IFRS Accounting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

Certain comparative amounts in the statement of financial position and statement of shareholders' equity have been adjusted to conform with the current period presentation. Specifically, the Reserve from common-control transaction of $(18,063) that was previously presented as its own account has been re-presented to be reflected as a reduction of Shareholders' capital. There were no changes to the operating results, cash flows or financial position of the Company as a result of this presentation change. The table below summarizes the impact of the recasted amounts in the 2023 comparatives:

	As previously reported	**Adjustment**	**As recast**
Shareholders' capital	**191,981**	(18,063)	173,918
Reserve from common-control transaction	**(18,063)**	18,063	-

The financial statements were authorized for issuance by the Board of Directors on April 23, 2025.

(b) Basis of measurement

These financial statements have been prepared on the historical cost basis.

Many of the Company's oil and natural gas activities involve undivided interests in jointly owned assets and these financial statements reflect only the Company's proportionate interest in such activities.

(c) Functional and presentation currency

The financial statements are presented in Canadian dollars, which is the functional currency of the Company.

(d) Use of estimates and judgments

The preparation of the financial statements in conformity with IFRS Accounting Standards as issued by the IASB requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur.

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

Cash-generating units ("CGU")
The Company's assets are aggregated into CGUs which are determined based on the smallest group of assets that generate cash inflows independent of other assets or groups of assets. Determination of the CGUs is subject to the Company's judgment and is based on geographical proximity, shared infrastructure, similar exposure to market risk, and materiality.

Impairment
Significant management judgment is required to analyze internal and external indicators of impairment or historical impairment reversal with the estimate of proved and probable oil and natural gas reserves being significant to the assessment. In determining the estimated recoverable amount of assets or CGUs, in the absence of quoted market prices, impairment tests are based on the estimate of proved and probable oil and natural gas reserves. The estimate of proved and probable oil and natural gas reserves includes significant assumptions related to: forecasted oil and natural gas commodity prices, forecasted production, forecasted operating costs, forecasted royalty costs, forecasted future development costs, discount rates and other relevant assumptions.

Exploration and evaluation assets
The application of the Company's accounting policy for exploration and evaluation ("E&E") assets requires the Company to make certain judgments as to future events and circumstances as to whether economic quantities of proved and probable oil and natural gas reserves will be found so as to assess if technical feasibility and commercial viability has been achieved.

Reserves
The Company uses estimated proved and probable oil and natural gas reserves to deplete its development and production assets included in property, plant, and equipment, to assess for indicators of impairment or impairment reversal on its CGU and, if any such indicators exist, to perform an impairment test to estimate the recoverable amount of the CGU. The Company's proved and probable oil and natural gas reserves represent the estimated quantities of oil, natural gas, and natural gas liquids ("NGLs") which geological, geophysical and engineering data demonstrate with a specified degree of certainty to be economically recoverable in future years from known reservoirs and which are considered commercially producible. Proved and probable oil and natural gas reserves requires estimation and are subject to assumptions regarding: forecasted oil and natural gas commodity prices, forecasted production, forecasted operating costs, forecasted royalty costs and forecasted future development costs. Changes in reported proved and probable oil and natural gas reserves can impact the carrying values of the Company's property, plant, and equipment, exploration and evaluation assets, the calculation of depletion expense, and the provision for decommissioning obligations due to changes in expected future cash flows. The estimated proved and probable oil and natural gas reserves are evaluated by independent third party reserve evaluators at least annually in accordance with the standards contained in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook.

Decommissioning obligations
Amounts recorded for decommissioning obligations requires 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, public expectations, market conditions, discovery and analysis of site conditions and changes in technology.

Deferred taxes
Deferred taxes are based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates, and the likelihood of assets being realized. Tax interpretations, regulations, and legislation in the various jurisdictions in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty. Judgments are also required to determine the likelihood of whether deferred income taxes at the end of the reporting period will be realized from future taxable earnings.

Current operating and reporting environment
Numerous factors beyond the Company's control influence the marketability and pricing of oil, natural gas, and NGLs, which may experience significant volatility. These factors include uncertainties in supply and demand driven by government policies, global economic conditions, sanctions and tariffs, shifts in global trade flows, changes in interest rates and inflation, actions by OPEC+, political and geopolitical instability, regulatory changes, ongoing conflicts, and other macroeconomic or political developments. Specifically, adverse changes in Canada and U.S. trade relations, particularly regarding tariffs and energy, could negatively affect the Company given the integration of North American energy markets. Given the uncertainty surrounding the magnitude, duration, and potential outcomes of these factors, the Company cannot currently predict their long-term impact on its operations, liquidity, financial condition, or results; however, the impact may be material.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. The Company considers the impact of the evolving worldwide demand for energy and global advancement of alternative sources of energy that are not sourced from fossil fuels. The ultimate period in which global energy markets can transition from carbon-based sources to alternative energy is highly uncertain and the Company will continue to monitor its estimates as the energy evolution continues. With respect to environmental, social and governance (ESG) and climate reporting, in December 2024, the Canadian Sustainability Standards Board released the final versions of the Canadian Sustainability Reporting Standards, CSDS 1 and CSDS 2 (collectively, the "Canadian Standards"). These standards closely align with the International Sustainability Standards Board's IFRS S1 and IFRS S2 standards, however, provide for additional transition relief regarding the timing of reporting, comparative information, non-climate related risks and opportunities, and Scope 3 GHG emissions. Currently, the adoption of the Canadian Standards remains voluntary, while the Canadian Securities Administrators are currently evaluating how and to what extent they will be incorporated into future reporting requirements. The Company continues to monitor the evolving regulations and the potential impact on the Company's results of operations, access to capital, and financial condition. The costs to comply with these standards cannot yet be quantified.

3. MATERIAL ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently by the Company to all periods presented in these financial statements, other than as described below.

(a) Joint arrangements

Many of the Company's oil and natural gas activities involve undivided interests in jointly owned assets and these financial statements reflect only the Company's proportionate interest in such activities. The Company has no arrangements classified as joint ventures.

(b) Financial instruments

Non-derivative financial instruments

Financial instruments are recognized initially at fair value. Measurement in subsequent periods is dependent on the financial instrument's classification. The initial classification of a financial asset into one of the following three categories depends on the Company's business model for managing its financial assets and the contractual terms of the cash flows: (i) amortized cost; (ii) fair value through other comprehensive income ("FVOCI"); or (iii) fair value through profit or loss ("FVTPL").

Financial assets designated at amortized cost are initially recognized at fair value, net of directly attributable transaction costs, and are subsequently measured at amortized cost using the effective interest rate method, net of any impairment.

Financial liabilities are classified and measured at amortized cost or FVTPL. Other financial liabilities are initially measured at fair value less attributable transaction costs and are subsequently measured at amortized cost using the effective interest method.

The Company's financial instruments classified and measured at amortized cost comprise cash, restricted cash deposits, accounts receivable, and accounts payable and accrued liabilities. The Company has not designated any financial instruments as FVOCI or FVTPL.

Financial assets and liabilities are offset and the net amount reported in the statement of financial position when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

Cash

Cash is comprised of cash held in bank accounts.

Share capital

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects.

(c) Property, plant, and equipment and exploration and evaluation assets

Recognition and measurement

Exploration and evaluation expenditures
Pre-license costs are recognized in earnings as incurred.

Exploration and evaluation costs, including the costs of acquiring undeveloped land and drilling costs, are initially capitalized until the drilling of the well is complete and the results have been evaluated. The costs are accumulated in cost centers by well, field, or exploration area pending determination of technical feasibility and commercial viability. The technical feasibility and commercial viability of extracting a mineral resource is generally considered to be determinable when proved or probable oil and natural gas reserves are determined to exist. If proved or probable oil and natural gas reserves are found, the accumulated costs and associated undeveloped land are transferred to development and production assets included in property, plant, and equipment. The exploration and evaluation costs are reviewed for impairment prior to any such transfer.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and are transferred to property, plant, and equipment, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to their respective CGUs.

Development and production costs
Items of property, plant, and equipment, which include development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The cost of development and production assets includes: transfers from exploration and evaluation assets, which generally include the cost to drill the well and the cost of the associated land upon determination of technical feasibility and commercial viability; the cost to complete and tie-in the well; facility costs; the cost of recognizing provisions for future restoration and decommissioning obligations; geological and geophysical costs; and directly attributable overhead.

Development and production assets are grouped into CGUs for impairment testing. The Company currently has one CGU located in northeast BC, being the Two Rivers CGU.

When significant parts of an item of property, plant, and equipment have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant, and equipment are determined by comparing the proceeds from disposal with the carrying amount of property, plant, and equipment and are recognized in earnings. The carrying amount of any replaced or disposed item of property, plant, and equipment is derecognized.

Subsequent costs

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant, and equipment are recognized as property, plant, and equipment only when they increase the future economic benefits embodied in the specific asset to which they relate. Capitalized property, plant, and equipment generally represent costs incurred in developing proved or probable oil and natural gas reserves and bringing in or enhancing production from such reserves and are accumulated on a field or area basis. The costs of the day-to-day servicing of property, plant, and equipment are recognized in operating expenses as incurred.

Non-monetary asset swaps

Exchanges or swaps of property, plant, and equipment are measured at fair value unless the exchange transaction lacks commercial substance or neither the fair value of the assets given up nor the assets received can be reliably estimated. 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 clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. Any gain or loss on derecognition of the asset given up is included in profit or loss. Exchanges or parts of exchanges that involve principally exploration and evaluation assets are measured at the carrying amount of the asset exchanged, reduced by the amount of any cash consideration received. No gain or loss is recognized unless the cash consideration received exceeds the carrying value of the asset held.

Depletion and depreciation

The Company depletes its net carrying value of development and production assets using the unit of production method by reference to the ratio of production in the period to the related proved and probable oil and natural gas reserves, taking into account estimated forecasted future development costs necessary to bring those reserves into production. Estimated salvage value of the assets at the end of their useful lives is also taken into account. The Company engages independent third party reserve evaluators to estimate the proved and probable oil and natural gas reserves.

The cost of office and other equipment is depreciated using the straight-line method over the estimated useful life of between three and six years.

Depreciation methods, useful lives, and salvage values are reviewed at each reporting date and, if necessary, changes are accounted for prospectively.

(d) Leases

The Company assesses whether a contract is a lease based on whether the contract conveys the right to control the use of an underlying asset for a period of time in exchange for consideration.

The Company recognizes a right-of-use ("ROU") asset and a lease liability at the lease commencement date. The ROU asset is initially measured at cost based on the initial amount of the lease liability adjusted for any lease payments made at or before the commencement date, plus any initial direct costs incurred and an estimate of costs to dismantle and remove the underlying asset or to restore the underlying asset or the site on which it is located, less any lease incentives received. The assets are depreciated to the earlier of the end of the useful life of the ROU asset or the lease term using the straight-line method as this most closely reflects the expected pattern of consumption of the future economic benefits. The Company includes ROU assets in property, plant, and equipment on the statement of financial position. The lease term includes periods covered by an option to extend if the Company is reasonably certain to exercise that option. In addition, the ROU asset is periodically reduced by impairment losses, if any, and adjusted for certain re-measurements of the lease liability.

The lease liability is initially measured at the present value of the lease payments that are not paid at the commencement date, discounted using the interest rate implicit in the lease or, if that rate cannot be readily determined, the Company's incremental borrowing rate. Generally, the Company uses its incremental borrowing rate as the discount rate.

The lease liability is measured at amortized cost using the effective interest method. It is re-measured when there is a change in future lease payments arising from a change in an index or rate, if there is a change in the Company's estimate of the amount expected to be payable under a residual value guarantee, or if the Company changes its assessment of whether it will exercise a purchase, extension or termination option. When the lease liability is re-measured in this way, a corresponding adjustment is made to the carrying amount of the ROU asset, or is recorded in earnings if the carrying amount of the ROU asset has been reduced to zero. Lease payments are applied against the lease obligation, with a portion reflected as interest expense using the effective interest rate method. The Company presents the lease liability as its own line item on the statement of financial position.

(e) Impairment

Financial assets

The Company has elected to measure loss allowances for its financial assets measured at amortized cost at an amount equal to lifetime expected credit losses ("ECLs") as its accounts receivable are due within a period of less than one year and are not considered to have a significant financing component. The maximum period considered when estimating ECLs is the maximum contractual period over which the Company is exposed to credit risk. ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e., the difference between the cash flows due to the Company in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the financial asset.

Non-financial assets

The Company assesses at each reporting date whether there is an indication that property, plant, and equipment within the Company's cash-generating unit may be impaired or that historical impairment may be reversed. If any such indication exists, then the cash-generating unit's recoverable amount is estimated. Exploration and evaluation assets are assessed for impairment when they are transferred to development and production assets included in property, plant, and equipment or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount. ROU assets may be tested as part of a cash-generating unit, as a separate cash-generating unit or as an individual asset.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (a cash-generating unit or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal.

Fair value less costs of disposal is determined to be the amount for which the asset could be sold in an arm's length transaction between knowledgeable and willing parties. Fair value less costs of disposal is generally determined using discounted cash flows from the estimate of proved and probable oil and natural gas reserves considering recent market transactions. These calculations are corroborated by valuation multiples or other available fair value indicators.

Value in use is determined from the estimate of proved and probable oil and natural gas reserves discounted to their present value using a pre-tax discount rate that reflects the current market assessments of the time value of money and risks specific to the asset.

An impairment loss is recognized if the carrying amount of a CGU exceeds its estimated recoverable amount. Impairment losses are recognized in earnings. Impairment losses recognized in respect of CGUs are allocated to the assets in the CGUs on a pro rata basis. Impairment losses recognized in prior periods are assessed each reporting date if facts or circumstances indicate that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

(f) Share based compensation

The Company uses the fair value method for valuing share based compensation. Under this method, the compensation cost attributed to stock options and restricted share units is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options and restricted share units that vest. Upon the settlement of the stock options and restricted share units, the previously recognized value in contributed surplus is recorded as an increase to share capital.

(g) Provisions

Provisions are recognized when the Company has a present obligation as a result of a past event that can be estimated with reasonable certainty. Provisions are measured by estimating the cash flows that the Company would pay to be relieved of the obligation. To the extent that provisions are estimated using a present value technique, such amounts are determined by discounting the estimated future cash flows at a risk-free pre-tax rate. Provisions are not recognized for future operating losses.

Decommissioning obligations
The Company's activities give rise to dismantling, decommissioning, and site disturbance remediation activities. A provision is made for the estimated cost of abandonment and site restoration and capitalized in the relevant asset category. The capitalized amount is depreciated on a unit of production basis over the life of the associated proved and probable oil and natural gas reserves. Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the reporting date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation, and changes in the risk-free rate. The increase in the provision due to the passage of time is recognized as accretion (within finance expenses) whereas increases or decreases due to changes in the estimated future cash flows or changes in the discount rate are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

(h) Revenue

The Company earns revenue from its production and sale of oil, natural gas and NGLs.

Revenue from the sale of oil, natural gas and NGLs is recognized based on the consideration specified in contracts with customers. The Company recognizes revenue when control of the product transfers to the customer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon.

The Company evaluates its arrangements with third parties and partners to determine if the Company is acting as the principal or as an agent. In making this evaluation, management considers if the Company obtains control of the product delivered, which is indicated by the Company having the primary responsibility for the delivery of the product, having the ability to establish prices or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

Tariffs, tolls and fees charged to other entities for use of pipelines and facilities owned by the Company are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

When allocating the transaction price realized in contracts with multiple performance obligations (sale of commodities and sale of transportation services), management is required to make estimates of the prices at which the Company would sell the product or service separately to customers.

(i) Finance income and expenses

Finance income and expense comprises interest expense on credit facilities, interest expense on lease obligations, costs associated with credit facility commitment and origination fees, accretion on decommissioning obligations and lease obligations, and interest income earned on cash in the bank.

(j) Income tax

Income tax expense is comprised of current and deferred tax. Income tax expense is recognized in earnings except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. 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 by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis, or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable earnings will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

(k) Per share amounts

Basic per share amounts are calculated by dividing the net earnings or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted per share amounts are determined by adjusting the weighted average number of common shares outstanding during the period for the effects of dilutive instruments such as stock options and restricted share units granted.

(l) New accounting standards and future accounting pronouncements

IAS 1 *Presentation of Financial Statements* was amended in January 2020 and October 2022 by the IASB to clarify the presentation requirements of liabilities as either current or non-current within the statement of financial position. The amendments apply retrospectively for annual reporting periods beginning on or after January 1, 2024. The Company adopted these amendments effective January 1, 2024 and the adoption did not have an impact on the Company's financial statements.

IFRS 18 *Presentation and Disclosure in Financial Statements* was issued by the IASB in April 2024. IFRS 18 introduces defined categories for income and expenses and certain defined subtotals in the statement of operations and comprehensive income (loss), required disclosures of certain management-defined performance measures, and aggregation and disaggregation principles for the grouping of information in the financial statements. IFRS 18 will replace IAS 1 and is effective for annual periods beginning on or after January 1, 2027. The standard requires retrospective application with early adoption permitted. The Company is currently evaluating the impact of adopting IFRS 18 on the financial statements.

In May 2024, the IASB issued amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* regarding the settlement of financial liabilities via electronic payment systems and the assessment of contractual cash flow characteristics of financial assets. The amendments are effective for annual periods beginning on or after January 1, 2026, and require retrospective application with early adoption permitted. The Company is currently evaluating the impact of adoption on its financial statements.

4. RESTRICTED CASH DEPOSITS

The Company has $4.9 million in restricted guaranteed investment certificates ("GIC's") with a Canadian chartered bank (December 31, 2023 - $7.3 million). These restricted GIC's are being held as security for $4.9 million of letters of guarantee to third parties relating to firm transportation agreements. Restricted cash deposits will be released as letters of guarantee are lowered or if the restricted GIC's are replaced by a credit facility (see note 8).

	December 31, 2024	December 31, 2023
Current	**-**	492
Long-term	**4,900**	6,784
	4,900	7,276

5. PROPERTY, PLANT, AND EQUIPMENT

Cost	Total
Balance, December 31, 2022	65,864
Additions	26,928
Disposal of equipment	(62)
Right-of-use asset additions (note 7)	1,038
Capitalized share based compensation	556
Change in decommissioning obligation estimates (note 9)	459
Balance, December 31, 2023	94,783
Additions	**1,206**
Derecognition of right-of-use asset (note 7)	**(1,038)**
Capitalized share based compensation	**111**
Change in decommissioning obligation estimates (note 9)	**551**
Balance, December 31, 2024	**95,613**

Accumulated Depletion, Depreciation, and Impairment	Total
Balance, December 31, 2022	46,811
Disposal of equipment	(62)
Depletion and depreciation	2,323
Balance, December 31, 2023	49,072
Derecognition of right-of-use asset (note 7)	**(577)**
Depletion and depreciation	**4,737**
Balance, December 31, 2024	**53,232**

Net Book Value	Total
December 31, 2023	45,711
December 31, 2024	**42,381**

During the year ended December 31, 2024, approximately $36 thousand (December 31, 2023 - $0.4 million) of directly attributable general and administrative costs were capitalized as expenditures on property, plant, and equipment (“PP&E”).

Depletion and depreciation

The calculation of depletion and depreciation expense for the year ended December 31, 2024 included an estimated $21.4 million (December 31, 2023 - $19.4 million) for forecasted future development costs associated with proved and probable undeveloped oil and natural gas reserves and excluded approximately $1.0 million (December 31, 2023 - $1.2 million) for the estimated salvage value of production equipment and facilities. Depletion expense on development and production assets was $4.3 million for the year ended December 31, 2024 (December 31, 2023 - $1.9 million).

Included in depletion and depreciation expense for the year ended December 31, 2024, is $0.4 million (December 31, 2023 - $0.4 million) related to the Company’s right-of-use assets. At December 31, 2024, the net book value of the right-of-use assets is $0.3 million (December 31, 2023 - $1.1 million).

Impairment assessment

The Company determined that there were no external or internal indicators of impairment or impairment reversal at December 31, 2024 and December 31, 2023 for its PP&E Two Rivers CGU and no impairment test was required.

6. EXPLORATION AND EVALUATION ASSETS

	Total
Balance, December 31, 2022	19,649
Additions	47,685
Change in decommissioning obligation estimates (note 9)	1,117
Capitalized share based compensation	432
Balance, December 31, 2023	68,883
Additions	**83,291**
Change in decommissioning obligation estimates (note 9)	**1,386**
Capitalized share based compensation	**667**
Lease expiries	**(49)**
Balance, December 31, 2024	**154,178**

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proved or probable oil and natural gas reserves and an assessment of technical feasibility and commercial viability. Additions represent the Company's share of costs incurred on exploration and evaluation assets during the period, consisting primarily of undeveloped land, drilling costs, and facility costs until the drilling of the well is complete and the results have been evaluated. Included in E&E assets at December 31, 2024 is approximately $135.5 million relating to pad drilling and completions and pipeline and facility construction costs related to the Company's Two Rivers East project (December 31, 2023 - $50.1 million). Included in this balance is $19.7 million of pipeline construction costs which was subsequently completed and sold to a third party midstream company (see note 22).

During the year ended December 31, 2024, the Company negotiated a reduction in royalties on certain lands in exchange for a royalty on additional lands.

During the year ended December 31, 2024, approximately $0.9 million (December 31, 2023 - $0.6 million) of directly attributable general and administrative costs were capitalized as expenditures on E&E assets.

During the year ended December 31, 2024, $49 thousand (December 31, 2023 - $nil) of land lease expiries have been included in depletion and depreciation expense.

At December 31, 2024 and December 31, 2023, the Company evaluated its E&E assets for indicators of impairment and as a result of this assessment management determined that an impairment test was not required to be performed.

7. LEASE OBLIGATIONS

At December 31, 2024, the Company had a lease obligation related to its head office lease. The lease obligation is discounted with an effective interest rate of 5.5% and the right-of-use asset is amortized based on the lease term. The lease expires November 30, 2027 with a renewal option of an additional five year term. Only the first term of the lease has been recognized as a right-of-use asset and lease obligation.

During the year ended December 31, 2024, the Company terminated its field equipment lease. The early termination of the lease for a lump sum payment of $0.2 million resulted in a loss on termination of $0.2 million.

	Total
Balance, December 31, 2022	540
Additions	1,038
Lease payments	(452)
Interest expense (note 14)	104
Balance, December 31, 2023	1,230
Termination	**(260)**
Lease payments	**(693)**
Interest expense (note 14)	**77**
Balance, December 31, 2024	**354**
Current	**110**
Long-term	**244**
	354

The total undiscounted amount of the estimated future cash flows to settle the lease obligations over the remaining lease term is $0.4 million. The Company's minimum lease payments are as follows:

	December 31, 2024
Within one year	127
Later than one year but not later than three years	257
Minimum lease payments	384
Amount representing interest expense	(30)
Present value of net lease payments	**354**

The expense recognized relating to short-term leases and leases of low-value assets for year ended December 31, 2024 was $3 thousand (December 31, 2023 - $26 thousand) and has been included in operating expenses.

For the year ended December 31, 2024, $0.2 million (December 31, 2023 - $0.2 million) of non-lease variable expenses relating to the head office lease have been included within general and administrative expenses.

8. CREDIT FACILITY

On October 4, 2024, the Company secured two revolving bank credit facilities for a total of $52.0 million from a Canadian chartered bank. The credit facilities are backed by reserves at Two Rivers West plus a $45.0 million letter of credit from a third party. The commitment from the third party is for a two-year term. During the term, Coelacanth expects that the lending value of producing reserves at Two Rivers East will allow for the credit facility to be renegotiated and the letter of credit to be returned.

The first credit facility is a $7.0 million revolving operating demand loan credit facility that bears interest at prime plus 3.0%. The undrawn portion of the credit facility is subject to a standby fee of 1.0%. Any outstanding letters of guarantee reduce the amount that can be borrowed under the credit facility and bear interest at 4.0%. During the year ended December 31, 2024, the Company redeemed $5.4 million of restricted cash deposit GIC's (see note 4) and issued letters of guarantee for the same amount under the revolving operating demand loan credit facility thereby reducing the amount available from $7.0 million to $1.6 million.

The second credit facility is a $45.0 million revolving operating demand loan that bears interest at prime plus 0.25%. The undrawn portion of the credit facility is subject to a standby fee of 0.125%. This credit facility is secured by a $45.0 million letter of credit from a third party. The letter of credit fee is 3.0% of the total $45.0 million face value of the letter of credit whether drawn or not for the first one-year term plus the period prior to the start of the first term. The first term starts the earlier of when drawn or December 31, 2024. The Company has the option to extend the term by an additional maximum one-year term for a fee of 6% of the drawn portion of the letter of credit that can be reduced at any time by repayment of the credit facility. The non-refundable third party letter of credit fees for the initial one-year term have been recognized as a financing obligation payable that are payable monthly until December 2025. The balance of the financing obligation payable at December 31, 2024 is $1.2 million (December 31, 2023 - $nil).

The credit facilities and letter of credit are secured by a $75.0 million fixed and floating charge debenture on the assets of the Company. The next review of the credit facilities by the bank is scheduled on or before June 30, 2025.

As at December 31, 2024, no amounts were drawn under either credit facility.

The credit facilities include a covenant requiring the Company to maintain an adjusted working capital ratio of not less than one-to-one. The adjusted working capital ratio, as defined by its creditor, is calculated as current assets plus any undrawn amounts available on its demand loan credit facilities less current liabilities excluding any current portion drawn on the demand loan credit facilities. The definition of current assets and current liabilities excludes the fair value of risk management contracts. The Company was compliant with this covenant at December 31, 2024.

9. DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from its ownership interest in development and production assets including well sites and gathering systems. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and facilities, and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows, adjusted for inflation at 1.81% per year (December 31, 2023 - 1.65%) required to settle the decommissioning obligations is approximately $16.7 million (December 31, 2023 - $13.3 million) which is estimated to be incurred over the next 33 years. At December 31, 2024, a risk-free rate of 3.32% (December 31, 2023 - 3.05%) was used to calculate the net present value of the decommissioning obligations.

	Year Ended December 31, 2024	Year Ended December 31, 2023
Balance, beginning of year	**8,869**	8,913
Provisions incurred	**1,407**	971
Provisions settled	**(1,427)**	(1,883)
Revisions in estimated cash flows	**565**	746
Revisions due to change of rates	**(35)**	(141)
Accretion (note 14)	**270**	263
Balance, end of year	**9,649**	8,869
Current	**2,118**	1,943
Long-term	**7,531**	6,926
	9,649	8,869

10. SHAREHOLDERS' CAPITAL AND WARRANTS

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares, Class A preferred shares, issuable in series, Class B preferred shares, issuable in series, and Class C preferred shares, issuable in series. No non-voting common shares or preferred shares have been issued.

Voting Common Shares	Number	Amount
Balance, December 31, 2022	425,106	97,259
Share issuances	101,875	79,867
Share issue costs	-	(4,116)
Exercise of warrants	278	119
Settlement of restricted share units	1,391	789
Balance, December 31, 2023	528,650	173,918
Settlement of restricted share units	**2,020**	**1,389**
Balance, December 31, 2024	**530,670**	**175,307**

In connection with the arrangement on May 31, 2022, involving Coelacanth, Leucrotta Exploration Inc. ("Leucrotta") and Vermilion Energy Inc. ("Vermilion"), the reserve created from the common-control transaction of $(18,063) represented the difference between the fair value of the Coelacanth shares issued to existing Leucrotta shareholders and the net book value of the acquired assets and assumed liabilities, and has been presented as a reduction against Shareholders' Capital. Prior period comparative amounts have been re-presented to reflect this change.

Warrants	Number	Amount
Balance, December 31, 2022	27,780	4,272
Issue of warrants	35,208	2,420
Warrant issue costs	-	(86)
Exercise of warrants	(278)	(44)
Balance, December 31, 2023	62,710	6,562
Extension of expiry date	-	417
Balance, December 31, 2024	**62,710**	**6,979**

The following table summarizes the warrants outstanding and exercisable at December 31, 2024:

Issue Date	Expiry Date	Exercise Price	Number
June 10, 2022	June 10, 2027	$0.27	27,502
November 15, 2023	June 30, 2025	$1.05	33,333
November 16, 2023	November 16, 2028	$0.80	1,875
			62,710

On November 15, 2023, the Company closed a bought-deal public financing through a syndicate of underwriters. The Company issued 100.0 million units of the Company ("Units") at a price of $0.80 per Unit for gross proceeds of $80.0 million. A Unit is comprised of one Coelacanth Share and 0.33 common share purchase warrants (one whole warrant being a "Warrant"). Each whole Warrant entitles the holder to purchase one Coelacanth Share at an exercise price of $1.05 per Coelacanth Share expiring on November 15, 2024. During the year ended December 31, 2024, the expiry date for the Warrants was extended to June 30, 2025.

The fair value of the bought-deal Warrants were estimated on the date of issue using the Black-Scholes-Merton option pricing model with the following assumptions:

	November 15, 2023
Risk-free interest rate (%)	**4.1**
Expected life (years)	**1.0**
Expected volatility (%)	**36.9**
Expected dividend yield (%)	**-**
Fair value of Warrants issued ($ per Warrant)	**0.05**

The fair value of the extension of the expiry date for the bought-deal Warrants were estimated on the date of extension using the Black-Scholes-Merton option pricing model with the following assumptions:

	November 15, 2024
Risk-free interest rate (%)	**3.2**
Expected life (years)	**0.6**
Expected volatility (%)	**38.5**
Expected dividend yield (%)	**-**
Fair value of Warrants issued ($ per Warrant)	**0.01**

On November 16, 2023, the Company closed a non-brokered private placement of 1,875,000 units of the Company to three employees ("Private Placement Units"), at a price of $0.80 per Private Placement Unit, for aggregate proceeds of $1.5 million. Each Private Placement Unit consists of one Coelacanth Share and one Warrant. Each Warrant entitles the holder to purchase one Coelacanth Share at a price of $0.80 per share expiring on November 16, 2028.

The Company recorded a share based compensation charge of $0.8 million equal to the difference between the fair value of the Private Placement Units received and the price paid for the Private Placement Units issued to certain officers and employees of the Company.

The fair value of the Private Placement Unit Warrants were estimated on the date of issue using the Black-Scholes-Merton option pricing model with the following assumptions:

	November 16, 2023
Risk-free interest rate (%)	**4.1**
Expected life (years)	**4.0**
Expected volatility (%)	**66.6**
Expected dividend yield (%)	**-**
Fair value of Warrants issued ($ per Warrant)	**0.42**

During the year ended December 31, 2023, 0.3 million Flow-through Warrants were exercised into Flow-through Shares. The Company incurred the required CDE expenditures of $75 thousand related to the Flow-through Shares during the year ended December 31, 2023. Effective March 31, 2023, the Minister of Finance (Canada) eliminated the flow-through share regime for oil and gas activities by no longer allowing oil and gas expenditures that are CDE to be renounced to flow-through shareholders in respect of flow-through share agreements made after March 31, 2023. As a result, on March 31, 2023, all unexercised Flow-through Warrants were amended to become Warrants.

11. SHARE BASED COMPENSATION PLANS

Stock options

The Company has authorized and reserved for issuance 53.1 million common shares under a stock option plan enabling certain officers, directors, employees, and consultants to purchase common shares. The Company will not issue options exceeding 10% of the shares outstanding at the time of the option grants (any performance share units “PSUs” or restricted share units “RSUs” described below are aggregated with any stock options for the 10% limit). Under the plan, the exercise price of each option equals the market price of the Company’s shares on the date of the grant and an option’s maximum term is ten years. At December 31, 2024, 17.0 million options were outstanding at an average exercise price of $0.72 per share.

	Number of Options	Weighted Average Exercise Price ($)
Balance, December 31, 2022	6,044	0.55
Granted	7,956	0.78
Forfeited	(751)	0.65
Balance, December 31, 2023	13,249	0.68
Granted	**5,687**	**0.79**
Settled	**(745)**	**0.54**
Forfeited	**(1,220)**	**0.76**
Balance, December 31, 2024	**16,971**	**0.72**
Exercisable, December 31, 2024	**5,687**	**0.65**

The following table summarizes the stock options outstanding and exercisable at December 31, 2024:

	Options Outstanding			Options Exercisable	
Exercise Price	**Number**	**Weighted Average Remaining Life (years)**	**Weighted Average Exercise Price**	**Number**	**Weighted Average Exercise Price**
$0.54 to $0.70	4,695	2.7	0.56	2,910	0.54
$0.71 to $0.79	4,652	3.0	0.75	1,830	0.75
$0.80 to $0.83	7,624	4.1	0.80	947	0.80
	16,971	3.4	0.72	5,687	0.65

The Company accounts for its share based compensation plans using the fair value method. Under this method, compensation cost is charged to earnings over the vesting period for stock options granted to officers, directors, employees, and consultants with a corresponding increase to contributed surplus. The stock options granted vest one-third on each of the first, second and third anniversaries of the date of grant.

The fair value of the stock options granted were estimated on the date of grant using the Black-Scholes-Merton option pricing model with the following weighted average assumptions:

	December 31, 2024	December 31, 2023
Risk-free interest rate (%)	**3.8**	3.4
Expected life (years)	**4.0**	4.0
Expected volatility (%)	**64.6**	67.4
Expected dividend yield (%)	**-**	-
Forfeiture rate (%)	**4.7**	3.1
Weighted average fair value of options granted ($ per option)	**0.41**	0.41

During the year ended December 31, 2024, the Company recognized $2.4 million (December 31, 2023 - $1.9 million) of share based compensation related to the stock options of which $2.0 million was recognized as an expense and $0.4 million was capitalized (December 31, 2023 - $1.4 million was recognized as an expense and $0.5 million was capitalized). At December 31, 2024 there was $1.7 million remaining as unrecognized share based compensation related to the stock options.

For the year ended December 31, 2024, the Company settled 0.7 million stock options (December 31, 2023 - nil) for $272 thousand in cash.

Subsequent to December 31, 2024, the Company granted 5.7 million stock options at an average exercise price of $0.81 per common share expiring five years from the date of grant and vest one-third on each of the first, second and third anniversaries of the date of grant.

Restricted share units

Subject to the terms and conditions of the performance and restricted share unit plan, each RSU award entitles the holder to an award value to be settled as to one-third on each of the first, second and third anniversaries of the date of grant. For the purpose of calculating share based compensation, the fair value of each award is determined at the grant date using the closing price of the Company's common shares. On the date of exercise, the Company has the option of settling the award value in cash (payment is based on the closing price of the Company’s common shares on day prior to exercise), common shares of the Company (one common share for each RSU), or a combination thereof. It is the Company’s intention to settle the RSUs in common shares of the Company.

	Number of RSUs
Balance, December 31, 2022	3,025
Granted	3,960
Exercised	(1,391)
Forfeited	(214)
Balance, December 31, 2023	5,380
Granted	**2,789**
Exercised	**(2,020)**
Settled	**(21)**
Forfeited	**(549)**
Balance, December 31, 2024	**5,579**

The weighted average market price of the Company's common shares used to value the RSUs granted during the year ended December 31, 2024 was $0.79 (December 31, 2023 - $0.78). During year ended December 31, 2024, the Company recognized $2.3 million (December 31, 2023 - $1.9 million) of share based compensation related to the RSUs of which $1.9 million was recognized as an expense and $0.4 million was capitalized (December 31, 2023 - $1.4 million was recognized as an expense and $0.5 million was capitalized). At December 31, 2024, there was $1.7 million remaining as unrecognized share based compensation related to the RSUs.

For the year ended December 31, 2024, the Company settled 21 thousand RSUs (December 31, 2023 - nil) for $16 thousand in cash.

Subsequent to December 31, 2024, the Company granted 3.6 million RSUs vesting one-third on each of the first, second and third anniversaries of the date of grant.

Performance share units

Subject to the terms and conditions of the performance and restricted share unit plan, each PSU award entitles the holder to an award value to be settled as to one-third on each of the first, second and third anniversaries of the date of grant multiplied by a payout multiplier ranging from 0 to 2.0 times and is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. For the purpose of calculating share based compensation, the fair value of each award is determined at the grant date using the closing price of the Company's common shares. On the date of exercise, the Company has the option of settling the award value in cash, common shares of the Company, or a combination thereof.

To date, no PSUs have been granted under the performance and restricted share unit plan.

12. PER SHARE AMOUNTS

The following table summarizes the weighted average number of shares used in the basic and diluted net loss per share calculations:

	December 31, 2024	December 31, 2023
Weighted average number of shares - basic	**529,804**	439,055
Dilutive effect of share based compensation plans	**-**	-
Weighted average number of shares - diluted	**529,804**	439,055

For the year ended December 31, 2024, 17.0 million stock options (December 31, 2023 - 13.2 million), 5.6 million RSUs (December 31, 2023 - 5.4 million), and 62.7 million warrants (December 31, 2023 - 62.7 million), were excluded from the weighted-average share calculation because they were anti-dilutive due to the net loss.

13. KEY MANAGEMENT PERSONNEL

The Company considers its directors and executives to be key management personnel. The key management personnel compensation is comprised of the following:

	December 31, 2024	December 31, 2023
Short-term wages and benefits and severance	**2,651**	2,312
Share based compensation (1)	**3,430**	3,344
Total (2,3)	**6,081**	5,656

(1) Represents the amortization of share based compensation expense associated with the Company's share based compensation plans granted to key management personnel and share based compensation recorded in conjunction with the management financings (see note 10).
(2) Balances outstanding and payable at December 31, 2024 were $nil (December 31, 2023 - $nil).
(3) At December 31, 2024, key management personnel included 10 individuals (December 31, 2023 - 12 individuals).

14. FINANCE EXPENSE

Finance expense includes the following:

	December 31, 2024	December 31, 2023
Interest expense	**533**	114
Lease interest expense (note 7)	**77**	104
Financing obligation payable (note 8)	**1,350**	-
Accretion of decommissioning obligations (note 9)	**270**	263
Finance expense	**2,230**	481

15. INCOME TAXES

The provision for income taxes in the statements of operations and comprehensive loss reflects an effective tax rate which differs from the expected statutory tax rate. The differences were accounted for as follows:

	December 31, 2024	December 31, 2023
Loss before taxes	**8,897**	6,573
Statutory income tax rate	**25.0%**	25.0%
Expected income tax recovery	**2,224**	1,643
(Increase) decrease in income taxes resulting from:		
Share based compensation and other non-deductible amounts	**(394)**	(413)
Change in unrecognized deferred tax asset	**(1,830)**	(1,230)
Deferred income tax recovery	**-**	-

The tax rate consists of the combined federal and provincial statutory tax rates for the Company for the years ended December 31, 2024 and December 31, 2023.

Under the terms of the arrangement on May 31, 2022, involving Coelacanth, Leucrotta and Vermilion, the Company acquired tax pools in the approximate amount of $85.0 million. The Company may not recognize deductible temporary differences of $45.6 million at December 31, 2024 (December 31, 2023 - $52.8 million) related to the excess of tax pools acquired over the carrying value of the net assets transferred because the common control transaction is not a business combination and is therefore subject to the initial recognition exemption under IAS 12 *Income Taxes*. Deferred income tax assets and liabilities are not recognized for temporary differences arising on the initial recognition of an asset or liability in a transaction that is not a business combination and at the time of the transaction, effects neither the accounting profit nor taxable profits.

At December 31, 2024 the Company has an unrecognized net deferred income tax asset due to a history of losses and it is not probable that future taxable profits, based on the estimated cash flows derived from the independently evaluated reserve report, would be sufficient to realize the deferred income tax asset at this time.

At December 31, 2024, the Company has estimated tax pools of $264.9 million (December 31, 2023 - $177.6 million) available for deduction against future taxable income.

The components and movements in net deferred income tax assets and liabilities are as follows:

	December 31, 2023	**Recognized in net loss**	**December 31, 2024**
Deferred income tax assets (liabilities)			
PP&E and E&E assets	(14,240)	(9,622)	(23,862)
Non-capital losses	14,240	9,622	23,862
Net deferred income tax asset (liability)	**-**	**-**	**-**

	December 31, 2022	**Recognized in net loss**	**December 31, 2023**
Deferred income tax assets (liabilities)			
PP&E and E&E assets	(4,750)	(9,490)	(14,240)
Decommissioning obligations	1,236	(1,236)	-
Non-capital losses	3,514	10,726	14,240
Net deferred income tax asset (liability)	**-**	**-**	**-**

Unrecognized deductible temporary differences are as follows:

	December 31, 2024	December 31, 2023
PP&E and E&E assets	**45,581**	52,847
Lease obligations	**354**	1,230
Restricted share units	**3,087**	1,825
Financing obligation payable	**1,238**	-
Decommissioning obligations	**9,649**	8,868
Share issue costs	**3,139**	4,098
Non-capital losses	**19,772**	7,193
Unrecognized deductible temporary differences	**82,820**	76,061

Non-capital losses of $115.2 million will expire between 2042 and 2045.

16. FAIR VALUE OF FINANCIAL INSTRUMENTS

The fair value of cash, restricted cash deposits, accounts receivable, and accounts payable and accrued liabilities at December 31, 2024 and December 31, 2023 approximated their carrying value.

The Company classified the fair value of its financial instruments at fair value according to the following hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 – observable inputs, such as quoted market prices in active markets;
- Level 2 – inputs, other than the quoted market prices in active markets, which are observable, either directly or indirectly;
- Level 3 – unobservable inputs for the asset or liability in which little or no market data exists, therefore requiring an entity to develop its own assumptions.

During the years ended December 31, 2024 and December 31, 2023, there were no transfers between level 1, level 2, and level 3 classified assets and liabilities as there are no financial instruments recognized at fair value.

17. FINANCIAL RISK MANAGEMENT

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities. The Company employs risk management strategies and policies to ensure that any exposure to risk is in compliance with the Company's business objectives and risk tolerance levels. Risk management is ultimately established by the Board of Directors and is implemented by management.

Market risk

Market risk is the risk that the fair value or future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk, and other price risk, such as commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns. The Company may use financial derivatives or physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

Foreign exchange risk
The prices received by the Company for the production of oil, natural gas, and NGLs are primarily determined in reference to US dollars, but are settled with the Company in Canadian dollars. The Company's cash flow from commodity sales will therefore be impacted by fluctuations in foreign exchange rates. The Company does not currently have any foreign exchange contracts in place.

Interest rate risk
The Company is exposed to interest rate risk on its cash, restricted cash deposit, and credit facility balances. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. The amount drawn on the Company's credit facilities at December 31, 2024 was $nil.

Commodity price risk
Oil and natural gas prices are impacted by not only the relationship between the Canadian and US dollar but also by world economic events that dictate the levels of supply and demand. The Company's oil, natural gas, and NGLs production is marketed and sold on the spot market to area aggregators based on daily spot prices that are adjusted for product quality and transportation costs. The Company's cash flow from product sales will therefore be impacted by fluctuations in commodity prices. In addition, the Company may enter into commodity price contracts to manage future cash flows.

The Company did not enter into commodity price contracts to manage future cash flows as at December 31, 2024.

Credit risk

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial asset fail to meet or discharge their obligation to the Company. A substantial portion of the Company's accounts receivable are with customers and joint interest partners in the oil and natural gas industry and are subject to normal industry credit risks. The Company generally grants unsecured credit but routinely assesses the financial strength of its customers and joint interest partners.

The Company sells the majority of its production to three petroleum and natural gas marketers and therefore is subject to concentration risk. Historically, the Company has not experienced any collection issues with its oil and natural gas marketers. Joint interest receivables are typically collected within one to three months of the joint interest billing being issued to the partner. The Company attempts to mitigate the risk from joint interest receivables by obtaining partner approval for significant capital expenditures prior to the expenditure being incurred. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint interest partners; however, in certain circumstances, the Company may cash call a partner in advance of expenditures being incurred.

The maximum exposure to credit risk is represented by the carrying amount of cash, restricted cash deposits and accounts receivable on the statement of financial position. At December 31, 2024, $4.1 million (87%) of the Company's outstanding accounts receivable were current and $0.6 million (13%) were outstanding for more than 90 days. During the year ended December 31, 2024, the Company deemed $35 thousand of outstanding accounts receivable to be uncollectable (December 31, 2023 - $44 thousand).

Cash and restricted cash deposits consist of bank balances placed with a financial institution with strong investment grade ratings which management believes the risk of loss to be remote. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade financial institution counterparties and by not entering into contracts for trading or speculative purposes.

Liquidity risk

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual, quarterly, and monthly capital expenditure budgets, which are monitored and updated as required, and requires authorizations for expenditures on projects to assist with the management of capital. In managing liquidity risk, the Company ensures that it has access to additional financing, including potential equity issuances and additional debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to insurable losses.

To facilitate its capital expenditure program, the Company has two revolving credit facilities (see note 8 for further details). At December 31, 2024, the Company had an adjusted working capital deficiency of $18.6 million and no amounts were drawn under its credit facilities. Subsequent to December 31, 2024, the Company received $22.7 million from a midstream company to finance a pipeline connecting Coelacanth facilities to the midstream company's gathering system. This amount will be repaid over a five-year period at an effective interest rate of 12.0%. The proceeds from the midstream company, in addition to available lending capacity, will be used to fund the remaining forecasted capital of approximately $35.0 million to complete facility and infrastructure projects and commence operations at Two River East in the first half of 2025.

The Company forecasts that it will have sufficient lending capacity and operational cash flows to meet its current and future obligations, to make any scheduled credit facility and associated interest payments, and to fund the other needs of the business for at least the next 12 months. Coelacanth's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

See note 22 for a summary of contractual commitments at December 31, 2024. The Company's accounts payable and accrued liabilities, current portion of lease obligations, and financing obligation payable are all due within the current operating period.

18. CAPITAL MANAGEMENT

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at an acceptable risk, and to maintain investor, creditor, and market confidence to sustain future development of the business.

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets. The Company considers its capital structure to include shareholders' equity and adjusted working capital. Adjusted working capital (deficiency) includes current assets and restricted cash deposits less current liabilities, excluding the current portion of decommissioning obligations. To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt, or adjust its capital spending to manage its current and projected debt levels.

	December 31, 2024	December 31, 2023
Shareholders' equity	**168,029**	172,519
Adjusted working capital (deficiency)	**(18,637)**	67,589

Management uses adjusted working capital (deficiency) as a measure to assess the Company's financial position and is reconciled as follows:

($000s)	**December 31, 2024**	December 31, 2023
Current assets	**11,579**	87,616
Less:		
Current liabilities	**(37,234)**	(28,754)
Working capital (deficiency)	**(25,655)**	58,862
Add:		
Restricted cash deposits	**4,900**	6,784
Current portion of decommissioning obligations	**2,118**	1,943
Adjusted working capital (deficiency)	**(18,637)**	67,589

In addition, management prepares annual, quarterly, and monthly budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The Company's share capital is not subject to external restrictions.

19. SUPPLEMENTAL DISCLOSURES

Presentation of expenses

The Company's statements of operations and comprehensive loss is prepared primarily by nature of expense, with the exception of employee compensation costs which are included in general and administrative expenses. Included in general and administrative expenses for the year ended December 31, 2024 are $3.9 million of wages and benefits (December 31, 2023 - $3.2 million).

20. SUPPLEMENTAL CASH FLOW INFORMATION

	December 31, 2024	December 31, 2023
Accounts receivable	**(591)**	(2,652)
Prepaid expenses and deposits	**(739)**	(47)
Accounts payable and accrued liabilities	**7,392**	18,877
Change in non-cash working capital	**6,062**	16,178
Relating to:		
Operating	**(261)**	(2,802)
Financing	**(969)**	273
Investing	**7,292**	18,707
Change in non-cash working capital	**6,062**	16,178

21. REVENUE

The Company sells its production pursuant to fixed or variable price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Commodity prices are based on market indices that are determined on a monthly or daily basis. Under the contracts, the Company is required to deliver variable volumes of oil, NGLs or natural gas to the contract counterparty. Revenue is recognized when a unit of production is delivered to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company's efforts to transfer production, and therefore the resulting revenue is allocated to the production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

The contracts generally have a term of one year or less, whereby delivery takes place throughout the contract period. Revenues are typically collected on the 25th day of the month following production.

The following table presents the Company's oil and natural gas revenues disaggregated by revenue source:

	December 31, 2024	December 31, 2023
Oil and condensate	**10,465**	4,538
Other natural gas liquids	**419**	192
Natural gas	**2,852**	1,933
Total revenue	**13,736**	6,663

Under certain marketing arrangements the Company will transfer title of its natural gas production to a third-party marketing company who will subsequently redeliver the natural gas production to an end customer by utilizing the Company's pipeline capacity. This portion representing the sale of transportation services is presented within natural gas revenue which is disaggregated in the below table by type:

	December 31, 2024	December 31, 2023
Natural gas production sales	**1,894**	1,279
Transportation revenue	**958**	654
Natural gas sales	**2,852**	1,933

The Company's revenue was generated entirely in the province of British Columbia. The majority of revenue resulted from sales whereby the transaction price was based on index prices. Of total oil and natural gas sales, three customers represented combined sales of 86% for the year ended December 31, 2024 (December 31, 2023 - three customers represented combined sales of 93%).

22. COMMITMENTS

The following is a summary of the Company's contractual obligations and commitments at December 31, 2024:

	2025	2026	2027	2028	2029	Thereafter	Total
Operating commitments	194	194	178	-	-	-	566
Firm transportation agreements	4,050	5,778	7,192	9,451	11,064	135,965	173,500
Firm processing agreements	3,212	8,736	8,910	9,089	9,270	57,038	96,255
Property, plant, and equipment	10,056	-	-	-	-	-	10,056
	17,512	14,708	16,280	18,540	20,334	193,003	280,377

Operating commitments include the non-lease variable components (operating expenses) of the head office lease (see note 7).

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has the following firm transportation commitments:

- 1.5 mmcf/d to deliver natural gas to the Alliance Trading Pool (ATP) and then to Chicago through October 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from January 1, 2023 through July 31, 2038.
- 50.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through May 31, 2038.
- 15.0 mmcf/d to deliver natural gas to Westcoast Station 2 from May 1, 2024 through April 30, 2055.
- 25.0 mmcf/d to deliver natural gas to Westcoast Station 2 from August 1, 2028 through July 31, 2043.

The Company assigned the following contracts to third parties, thus reducing its commitment:

- 4.4 mmcf/d to deliver natural gas to Westcoast Station 2 from April 1, 2023 through March 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from June 1, 2023 through December 31, 2027.
- 20.0 mmcf/d to deliver natural gas to Westcoast Station 2 from October 1, 2023 through October 31, 2026.
- 10.0 mmcf/d to deliver natural gas to Westcoast Station 2 from November 1, 2024 through December 31, 2025.

The impact of the reduced commitments are reflected in the table above.

Firm processing agreements include 30.0 mmcf/d of processing services at a gas processing facility for a period of 10 years. This is expandable by any volume up to an additional 30.0 mmcf/d (60.0 mmcf/d total) at the election of the Company at any date up to July 1, 2025 for the remainder of the original term. As part of the arrangement, the midstream company has agreed to fund the extension of their gathering system to certain contractual thresholds pending the achievement of certain project milestones. Subsequent to December 31, 2024, the Company received $22.7 million from the midstream company. The Company is required to repay the principal amount over a five-year period at an effective interest rate of 12.0%.

CORPORATE INFORMATION

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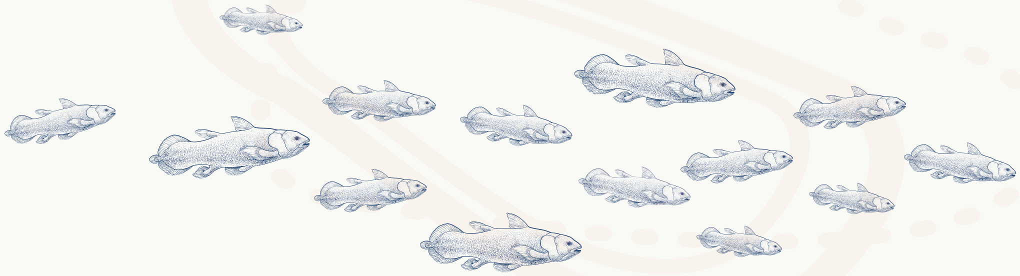

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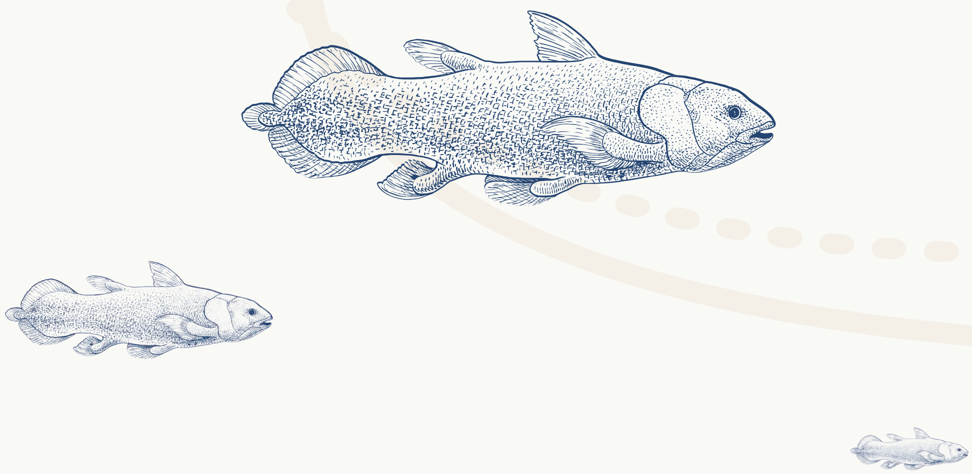

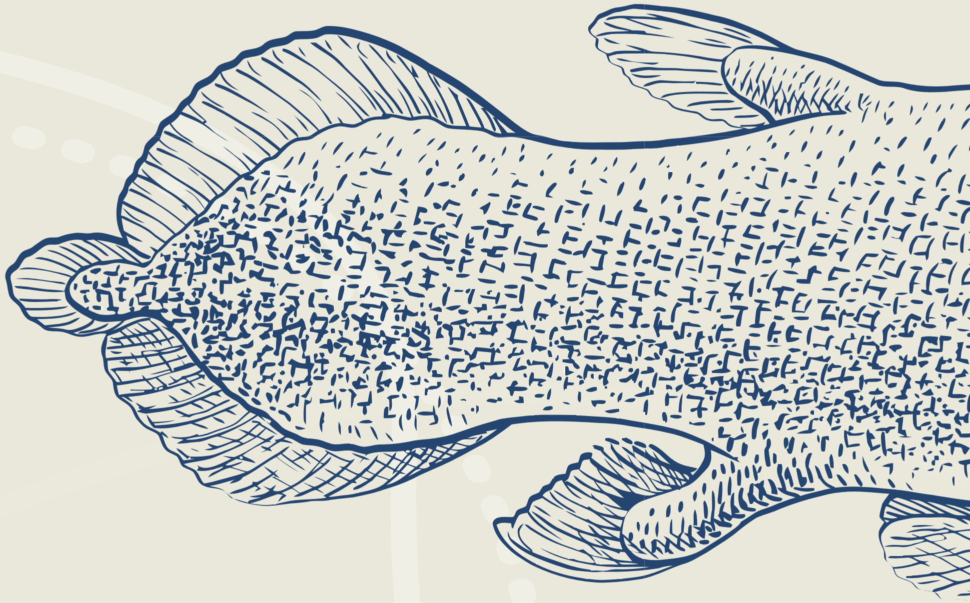

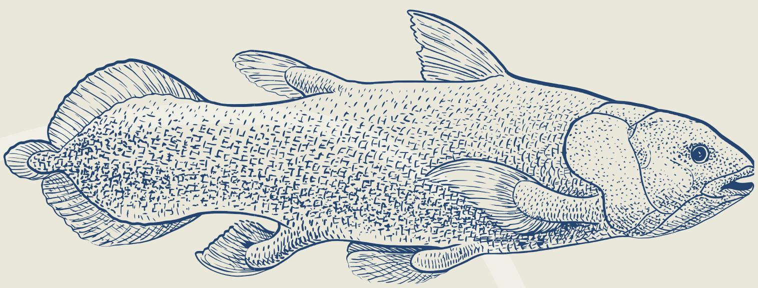

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