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**			**Year Ended**		
	December 31			**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.