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

November 19, 2025

The MD&A should be read in conjunction with the unaudited condensed interim financial statements and related notes for the three and nine months ended September 30, 2025 and the audited financial statements and related notes for the year ended December 31, 2024. The unaudited condensed interim 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
GJ	Gigajoules
GJ/d	Gigajoules 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) 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 September 30		**Nine Months Ended September 30**	
($000s)	**2025**	2024	**2025**	2024
Transportation expenses	**1,168**	1,055	**2,498**	2,426
Unutilized transportation	**(119)**	(757)	**(699)**	(1,504)
Net transportation expenses (non-GAAP)	**1,049**	298	**1,799**	922

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 September 30		**Nine Months Ended September 30**	
($000s)	**2025**	2024	**2025**	2024
Oil and natural gas sales	**11,372**	2,362	**18,866**	9,192
Royalties	**(2,324)**	(383)	**(3,725)**	(1,878)
Operating expenses	**(2,349)**	(767)	**(4,272)**	(2,549)
Net transportation expenses	**(1,049)**	(298)	**(1,799)**	(922)
Operating netback (non-GAAP)	**5,650**	914	**9,070**	3,843

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 September 30		**Nine Months Ended September 30**	
($000s)	**2025**	2024	**2025**	2024
Capital expenditures – property, plant, and equipment	**4,238**	396	**5,276**	973
Capital expenditures – exploration and evaluation assets	**1,866**	15,364	**40,802**	18,572
Capital expenditures (non-GAAP)	**6,104**	15,760	**46,078**	19,545

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 (deficiency) 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 (deficiency) and reconciliation to working capital (deficiency) 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

Coelacanth is continuing to work through its business plan of delineating and developing its large Montney resource base at Two Rivers that encompasses over 150 contiguous sections of Montney land tenure.

We are currently drilling three additional development wells on the 5-19 pad and will systematically bring on production from these wells plus prior drilled wells on the pad from now through early February.

Future development will consist of continued drilling in the vicinity of the 5-19 pad while significant step-outs will be incorporated into the capital budget to accelerate the delineation of the resource both aerially through the land base and vertically through the various Montney zones present on the land base.

We look forward to reporting on future developments as they arise.

SUMMARY OF FINANCIAL RESULTS	**Three Months Ended September 30**			**Nine Months Ended September 30**		
($000s, except per share amounts)	**2025**	2024	% Change	**2025**	2024	% Change
Oil and natural gas sales	**11,372**	2,362	381	**18,866**	9,192	105
Cash flow from (used in) operating activities	**4,712**	(3,730)	(226)	**4,054**	(954)	(525)
Per share - basic and diluted [3]	**0.01**	(0.01)	(200)	**0.01**	(-)	(100)
Adjusted funds flow (used) [1]	**2,386**	(207)	(1,253)	**533**	1,133	(53)
Per share - basic and diluted	**-**	(-)	(-)	**-**	-	-
Net loss	**(1,764)**	(2,464)	(28)	**(8,845)**	(5,994)	48
Per share - basic and diluted	**(-)**	(-)	-	**(0.02)**	(0.01)	100
Total assets				**246,957**	192,279	28
Total long-term liabilities				**27,482**	7,928	247
Adjusted working capital (deficiency) [2]				**(46,606)**	47,264	(199)

(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 increased in the first nine months of 2025 compared to 2024 as a result of the initiation of commercial production at Two Rivers East part way through June 2025. Cash flow and adjusted funds flow increased mainly as a result of increased production and operating netbacks partially offset by increased interest expense, lower interest income and payments on financing obligation.

PRODUCTION	Three Months Ended September 30			Nine Months Ended September 30		
	2025	2024	% Change	**2025**	2024	% Change
Average Daily Production [1]						
Oil and condensate (bbls/d)	**1,372**	221	521	**703**	268	162
Other NGLs (bbls/d)	**92**	33	179	**48**	36	33
Oil and NGLs (bbls/d)	**1,464**	254	476	**751**	304	147
Natural gas (mcf/d)	**10,896**	3,450	216	**6,050**	3,702	63
Oil equivalent (boe/d)	**3,280**	829	296	**1,759**	921	91

(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 3,280 boe/d and 1,759 boe/d for the three and nine months ended September 30, 2025, respectively, from 829 boe/d and 921 boe/d for the comparative periods in 2024. The increase in production was the result of the initiation of commercial production at Two Rivers East part way through June 2025.

Coelacanth's production profile for the third quarter of 2025 shifted more towards oil and NGLs when compared to the comparative quarter in 2024 as the result of flush oil production from initiation of commercial production at Two Rivers East which will trend back to a higher natural gas weighting as the wells continue to produce. The Q3 2025 weighting was 55% natural gas (Q3 2024 - 69%) and 45% oil and NGLs (Q3 2024 - 31%).

OIL AND NATURAL GAS SALES	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Oil and condensate	**10,068**	1,820	453	**15,614**	6,674	134
Other NGLs	**221**	95	133	**372**	331	12
Oil and NGLs	**10,289**	1,915	437	**15,986**	7,005	128
Natural gas	**1,083**	447	142	**2,880**	2,187	32
Total	**11,372**	2,362	381	**18,866**	9,192	105
Average Sales Price						
Oil and condensate ($/bbl)	**79.73**	89.68	(11)	**81.36**	90.88	(10)
Other NGLs ($/bbl)	**26.40**	31.39	(16)	**28.48**	33.20	(14)
Oil and NGLs ($/bbl)	**76.41**	82.10	(7)	**77.99**	84.00	(7)
Natural gas production sales and transportation revenue ($/mcf)	**1.08**	1.41	(23)	**1.74**	2.16	(19)
Combined ($/boe)	**37.69**	30.99	22	**39.28**	36.41	8

Revenue totaled $11.4 million and $18.9 million for the three and nine months ended September 30, 2025, respectively, compared to $2.4 million and $9.2 million for the comparative periods in 2024. The increase in revenue was mainly the result of the increase in production resulting from initiation of commercial production at Two Rivers East part way through June 2025.

In June 2025, the Company commenced initial production from three of the nine previously drilled 5-19 pad wells. The Company is now producing from four of the 5-19 wells and aims to have all nine wells on production by year-end. The Company has chosen to moderate the pace of wells brought on-stream in response to natural gas prices at the Station 2 hub.

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

Commodity Pricing	Three Months Ended September 30			Nine Months Ended September 30		
	2025	2024	% Change	**2025**	2024	% Change
Oil and NGLs						
Corporate price ($CDN/bbl)	**76.41**	82.10	(7)	**77.99**	84.00	(7)
Canadian light sweet ($CDN/bbl)	**85.00**	98.43	(14)	**88.70**	99.95	(11)
West Texas Intermediate ("WTI") ($US/bbl)	**64.93**	75.13	(14)	**66.70**	77.55	(14)
Natural gas						
Corporate price ($CDN/mcf)	**1.08**	1.41	(23)	**1.74**	2.16	(19)
AECO price ($CDN/mcf)	**0.61**	0.70	(13)	**1.49**	1.35	10
Westcoast Station 2 ($CDN/mcf)	**0.46**	0.51	(10)	**0.68**	1.13	(40)
Chicago City Gate ($US/mmbtu)	**2.77**	1.79	55	**3.21**	2.11	52
Exchange rate						
CDN/US dollar exchange rate	**0.7261**	0.7331	(1)	**0.7153**	0.7352	(3)

Future prices received from the sale of the products may fluctuate as a result of market factors. 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 89.9% and 87.9% of Canadian light sweet prices for the three and nine months ended September 30, 2025, respectively, consistent with 83.4% and 84.0% for the comparative periods in 2024. Coelacanth's liquids mix during the third quarter of 2025 was approximately 94% oil, condensate and pentanes, 4% butane and 2% propane (Q3 2024 - 87% oil, condensate and pentanes, 8% butane and 5% propane). The increase in light oil, condensate and pentanes was due to flush oil production with the commencement of commercial production at Two Rivers East during June 2025, which will shift to a higher natural gas weighting over time.

Corporate average natural gas prices were 28.3% and 38.8% of Chicago City Gate price (converted to Canadian dollars) for the three and nine months ended September 30, 2025, respectively, down from 57.7% and 75.3% for the comparative periods in 2024 due to the decline in Westcoast Station 2 pricing and a higher percentage of gas sales linked to Westcoast Station 2 in 2025. 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.

The Company entered into the following commodity price contracts to help manage future cash flows:

Commodity	Period	Type of Contract	Quantity	Contract Price
Oil	November 1, 2025 - April 30, 2026	Physical Sales	500 bbls/d	WTI CDN $86.86/bbl
Natural Gas	November 1, 2025 - December 31, 2025	Physical Sales	10,000 GJ/d	Westcoast Station 2 CDN $2.03/GJ
Natural Gas	December 1, 2025 - December 31, 2025	Physical Sales	5,000 GJ/d	Westcoast Station 2 CDN $2.10/GJ
Natural Gas	January 1, 2026 - March 31, 2026	Physical Sales	10,000 GJ/d	Westcoast Station 2 CDN $2.49/GJ

The Company accounts for any physical sales contracts as executory contracts and as such are not recorded at fair value on the Statement of Financial Position. Settlements on these physical sales contracts are recognized in oil and natural gas sales.

ROYALTIES	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Oil and NGLs	**2,318**	362	540	**3,528**	1,645	114
Natural gas	**6**	21	(71)	**197**	233	(15)
Total	**2,324**	383	507	**3,725**	1,878	98
Average Royalty Rate (% of sales)						
Oil and NGLs	**22.5**	18.9	19	**22.1**	23.5	(6)
Natural gas	**0.6**	4.7	(87)	**6.8**	10.7	(36)
Combined	**20.4**	16.2	26	**19.7**	20.4	(3)

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 $2.3 million and $3.7 million for the three and nine months ended September 30, 2025, respectively, compared to $0.4 million and $1.9 million for the comparative periods in 2024. The increase in Q3 2025 from Q3 2024 was mainly as a result of the increased production and revenue at Two Rivers East. The new oil wells at Two Rivers East currently have high production rates resulting in near maximum crown royalty rates based on the sliding scale rate formula. This increase in oil and NGLs royalties was partially offset by decreased natural gas royalties due to the decline of natural gas pricing and the result that had on the sliding scale rate formula.

OPERATING EXPENSES [1]	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Oil and NGLs	**1,066**	234	356	**1,823**	842	117
Natural gas	**1,283**	533	141	**2,449**	1,707	43
Operating expenses	**2,349**	767	206	**4,272**	2,549	68
Average operating expenses						
Oil and NGLs ($/bbl)	**7.92**	10.07	(21)	**8.90**	10.10	(12)
Natural gas ($/mcf)	**1.28**	1.68	(24)	**1.48**	1.68	(12)
Combined ($/boe)	**7.79**	10.07	(23)	**8.90**	10.10	(12)

(1) Where multiple product types are attributable to a single well, the operating expenses attributable to that well are allocated based on the proportionate production of each product.

Per unit operating expenses decreased to $7.79/boe and $8.90/boe for the three and nine months ended September 30, 2025, respectively, from $10.07/boe and $10.10/boe in the comparative periods in 2024 as a result of increased production at Two Rivers East.

NET TRANSPORTATION EXPENSES	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Oil and NGLs	**573**	56	923	**844**	192	340
Natural gas	**476**	242	97	**955**	730	31
Net transportation expenses (non-GAAP)	**1,049**	298	252	**1,799**	922	95
Unutilized transportation	**119**	757	(84)	**699**	1,504	(54)
Transportation expenses	**1,168**	1,055	11	**2,498**	2,426	3
Average transportation expenses						
Oil and NGLs ($/bbl)	**4.25**	2.36	80	**4.11**	2.30	79
Natural gas ($/mcf)	**0.48**	0.76	(37)	**0.58**	0.72	(19)
Net transportation expenses ($/boe)	**3.48**	3.91	(11)	**3.75**	3.65	3
Unutilized transportation ($/boe)	**0.39**	9.94	(96)	**1.45**	5.96	(76)
Transportation expenses ($/boe)	**3.87**	13.85	(72)	**5.20**	9.61	(46)

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.

Net transportation expenses for oil and NGLs increased on a per unit basis to $4.25/bbl and $4.11/bbl for the three and nine months ended September 30, 2025, respectively, compared to $2.36/bbl and $2.30/bbl for the comparative periods in 2024 as a result of new oil wells at Two Rivers East that have higher trucking costs than legacy wells at Two Rivers West.

Net transportation expenses for natural gas decreased on a per unit basis to $0.48/mcf and $0.58/mcf for the three and nine months ended September 30, 2025, respectively, compared to $0.76/mcf and $0.72/mcf for the comparative periods in 2024 as a result of increased natural gas production from new wells at Two Rivers East. Natural gas production exceeding the 1.5 mmcf/d being delivered to Chicago at higher transportation rates are being delivered to Westcoast Station 2 at lower transportation rates.

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. See 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 October 1, 2025 through December 31, 2025. In addition, the Company has mitigated and reduced its Westcoast Station 2 commitment in 2026 to various levels (refer to “Contractual Obligations” section).

OPERATING NETBACK	Three Months Ended September 30			Nine Months Ended September 30		
	2025	2024	% Change	**2025**	2024	% Change
Oil and NGLs ($/bbl)						
Revenue	**76.41**	82.10	(7)	**77.99**	84.00	(7)
Royalties	**(17.22)**	(15.52)	11	**(17.21)**	(19.73)	(13)
Operating expenses	**(7.92)**	(10.07)	(21)	**(8.90)**	(10.10)	(12)
Net transportation expenses (non-GAAP)	**(4.25)**	(2.36)	80	**(4.11)**	(2.30)	79
Operating netback (non-GAAP)	**47.02**	54.15	(13)	**47.77**	51.87	(8)
Natural gas ($/mcf)						
Revenue	**1.08**	1.41	(23)	**1.74**	2.16	(19)
Royalties	**(0.01)**	(0.06)	(83)	**(0.12)**	(0.23)	(48)
Operating expenses	**(1.28)**	(1.68)	(24)	**(1.48)**	(1.68)	(12)
Net transportation expenses (non-GAAP)	**(0.48)**	(0.76)	(37)	**(0.58)**	(0.72)	(19)
Operating netback (loss) (non-GAAP)	**(0.69)**	(1.09)	(37)	**(0.44)**	(0.47)	(6)
Combined ($/boe)						
Revenue	**37.69**	30.99	22	**39.28**	36.41	8
Royalties	**(7.70)**	(5.02)	53	**(7.76)**	(7.44)	4
Operating expenses	**(7.79)**	(10.07)	(23)	**(8.90)**	(10.10)	(12)
Net transportation expenses (non-GAAP)	**(3.48)**	(3.91)	(11)	**(3.75)**	(3.65)	3
Operating netback (non-GAAP)	**18.72**	11.99	56	**18.87**	15.22	24

During the three and nine months ended September 30, 2025, Coelacanth generated an operating netback (see "Non-GAAP and Other Financial Measures") of $18.72/boe and $18.87/boe, respectively, up from $11.99/boe and $15.22/boe for the comparative periods in 2024 mainly as the result of the increased oil content in the Company's product mix from new oil wells at Two Rivers East which have much higher netbacks than gas production.

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

	Three Months Ended September 30			Nine Months Ended September 30		
($/boe)	**2025**	2024	% Change	**2025**	2024	% Change
Operating netback	**18.72**	11.99	56	**18.87**	15.22	24
Depletion and depreciation	**(10.26)**	(14.89)	(31)	**(11.41)**	(14.71)	(22)
General and administrative expenses	**(4.61)**	(12.51)	(63)	**(9.14)**	(13.90)	(34)
Share based compensation	**(3.82)**	(13.81)	(72)	**(7.39)**	(12.72)	(42)
Finance expense	**(5.64)**	(2.71)	108	**(8.36)**	(1.72)	386
Finance income	**0.16**	9.54	(98)	**0.46**	10.03	(95)
Unutilized transportation	**(0.39)**	(9.94)	(96)	**(1.45)**	(5.96)	(76)
Net loss	**(5.84)**	(32.33)	(82)	**(18.42)**	(23.76)	(22)

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

	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Operating netback	**5,650**	914	518	**9,070**	3,843	136
Depletion and depreciation	**(3,097)**	(1,135)	173	**(5,481)**	(3,713)	48
General and administrative expenses	**(1,393)**	(955)	46	**(4,389)**	(3,509)	25
Share based compensation	**(1,151)**	(1,052)	9	**(3,550)**	(3,211)	11
Finance expense	**(1,703)**	(206)	727	**(4,016)**	(433)	827
Finance income	**49**	727	(93)	**220**	2,533	(91)
Unutilized transportation	**(119)**	(757)	(84)	**(699)**	(1,504)	(54)
Net loss	**(1,764)**	(2,464)	(28)	**(8,845)**	(5,994)	48

DEPLETION AND DEPRECIATION	Three Months Ended September 30			Nine Months Ended September 30		
	2025	2024	% Change	**2025**	2024	% Change
Depletion and depreciation ($000s)	**3,097**	1,135	173	**5,481**	3,713	48
Depletion and depreciation ($/boe)	**10.26**	14.89	(31)	**11.41**	14.71	(22)

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. Certain facility and pipeline assets included within PP&E are being depreciated on a straight-line basis over their estimated useful lives of 30 years. Depletion and depreciation for the three and nine months ended September 30, 2025 increased to $3.1 million and $5.5 million, respectively, from $1.1 million and $3.7 million for the comparative periods in 2024 due to increased production. On a per boe basis, depletion and depreciation for the three and nine months ended September 30, 2025 decreased to $10.26/boe and $11.41/boe, respectively, from $14.89/boe and $14.71/boe for the comparative periods in 2024. The Company commenced depleting and depreciating the Two Rivers East development project costs in June 2025 upon the transfer from exploration and evaluation assets to PP&E.

Included in depletion and depreciation expense for the three and nine months ended September 30, 2025, is $26 thousand (September 30, 2024 - $0.1 million) and $69 thousand (September 30, 2024 - $0.3 million), respectively, related to the Company's right-of-use assets.

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

In June 2025, as a result of all wells being capable of production due to the completion of the new battery facility, the Company transferred its Two Rivers East development project costs from exploration and evaluation assets to PP&E. The Company completed the mandatory impairment test upon transfer and no impairment was recorded.

At September 30, 2025 and September 30, 2024, 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 September 30, 2025 and September 30, 2024, 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 September 30**			**Nine Months Ended September 30**		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
G&A expenses (gross)	**1,463**	1,177	24	**4,618**	3,804	21
G&A capitalized	**(70)**	(222)	(68)	**(229)**	(295)	(22)
G&A expenses (net)	**1,393**	955	46	**4,389**	3,509	25
G&A expenses ($/boe)	**4.61**	12.51	(63)	**9.14**	13.90	(34)

During the three and nine months ended September 30, 2025, net general and administrative expenses ("G&A") increased to $1.4 million and $4.4 million, respectively, compared to $1.0 million and $3.5 million for the comparative periods in 2024 mainly due to higher employment costs.

On a per unit basis G&A was $4.61/boe and $9.14/boe for the three and nine months ended September 30, 2025, respectively, compared to $12.51/boe and $13.90/boe for the comparative periods in 2024. The decline in Q3 2025 from Q3 2024 was the result of increased production from the initiation of commercial production at Two Rivers East.

SHARE BASED COMPENSATION	**Three Months Ended September 30**			**Nine Months Ended September 30**		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Share based compensation (gross)	**1,286**	1,391	(8)	**4,070**	3,879	5
Share based compensation (capitalized)	**(135)**	(339)	(60)	**(520)**	(668)	(22)
Share based compensation (net)	**1,151**	1,052	9	**3,550**	3,211	11
Share based compensation ($/boe)	**3.82**	13.81	(72)	**7.39**	12.72	(42)

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 restricted share units ("RSUs") granted to officers, directors, employees, and consultants with a corresponding increase to contributed surplus.

Share based compensation expense was $1.2 million and $3.6 million for the three and nine months ended September 30, 2025, respectively, consistent with $1.1 million and $3.2 million for the comparative periods in 2024.

FINANCE EXPENSE	**Three Months Ended September 30**			**Nine Months Ended September 30**		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Interest expense	**840**	116	624	**1,816**	162	1,021
Other obligations interest expense	**623**	20	3,015	**840**	68	1,135
Amortization of financing costs	**161**	-	100	**535**	-	100
Accretion of other obligations	**-**	-	-	**614**	-	100
Accretion of decommissioning obligations	**79**	70	13	**211**	203	4
Finance expense	**1,703**	206	727	**4,016**	433	827
Finance expense ($/boe)	**5.64**	2.71	108	**8.36**	1.72	386

Accretion expense of decommissioning obligations was consistent for the three and nine months ended September 30, 2025 compared to the same periods in 2024. Interest expense relates to interest expense and standby fees on the credit facilities and outstanding letters of guarantee for firm transportation agreements. The large increase stems from moving from a positive cash balance at September 30, 2024 to being drawn $44.0 million on the Company's credit facilities at September 30, 2025 as a result of capital expenditures during the past twelve months. The increase in interest on other obligations is the result of a $22.7 million obligation to a midstream company funding the extension of their gathering system to connect to the Company's Two Rivers East project. Commencing June 2025, the Company is required to repay the principal amount over a five-year period at an interest rate of 12.0%.

FINANCE INCOME

Finance income relates to interest earned on cash in the bank. Finance income totaled $49 thousand and $0.2 million for the three and nine months ended September 30, 2025, respectively, compared to $0.7 million and $2.5 million for the comparative periods in 2024. The decrease corresponds to the decrease in the Company's cash balance over the comparative periods mainly due to capital expenditures during the past twelve months.

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 September 30, 2025 total approximately $301.0 million (December 31, 2024 - $264.9 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 September 30			Nine Months Ended September 30		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Cash flow from (used in) operating activities	**4,712**	(3,730)	(226)	**4,054**	(954)	(525)
Add (deduct):						
Decommissioning expenditures	**198**	790	(75)	**385**	1,266	(70)
Change in restricted cash deposits	**-**	2,139	(100)	**-**	2,985	(100)
Change in non-cash working capital	**(2,524)**	594	(525)	**(3,906)**	(2,164)	80
Adjusted funds flow (used) (non-GAAP)	**2,386**	(207)	(1,253)	**533**	1,133	(53)

Adjusted funds flow (see "Non-GAAP and Other Financial Measures") was $2.2 million ($nil per basic and diluted share) and $0.5 million ($nil per basic and diluted share) for the three and nine months ended September 30, 2025, respectively, compared to adjusted funds used of $0.2 million ($nil per basic and diluted share) and adjusted funds flow of $1.1 million ($nil per basic and diluted share) for the comparative periods in 2024. The large increase for the three months ended September 30, 2025 was mainly the result of increased production and operating netbacks partially offset by increased interest expense, lower interest income and payments on the financing obligation. This is the result of the significant upfront capital costs associated with the Two Rivers East development project which commenced production in June 2025.

Cash flow from operating activities was $4.7 million ($0.01 per basic and diluted share) and $4.1 million ($0.01 per basic and diluted share) during the three and nine months ended September 30, 2025, respectively, compared to cash flow used in operating activities of $3.7 million ($0.01 per basic and diluted share) and $1.0 million ($nil per basic and diluted share) for the comparative periods in 2024. 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. The increase is consistent with the increase in adjusted funds flow (used) for the same comparative periods.

NET LOSS

The Company incurred net losses of $1.8 million ($nil per basic and diluted share) and $8.8 million ($0.02 per basic and diluted share) for the three and nine months ended September 30, 2025, respectively, compared to $2.5 million ($nil per basic and diluted share) and $6.0 million ($0.01 per basic and diluted share) for the comparative periods in 2024. The increase for the nine months ended September 30, 2025 was mainly the result of increased interest expense and depletion and depreciation and lower interest income expense partially offset by increased operating netbacks.

CAPITAL EXPENDITURES	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2025**	2024	% Change	**2025**	2024	% Change
Land	**2,040**	98	1,982	**2,436**	545	347
Drilling, completions, and workovers	**241**	8,469	(97)	**833**	9,080	(91)
Equipment	**3,784**	7,089	(47)	**42,688**	9,783	336
Geological and geophysical	**39**	104	(63)	**121**	137	(12)
Total expenditures	**6,104**	15,760	(61)	**46,078**	19,545	136

During the three and nine months ended September 30, 2025 and September 30, 2024, the Company continued with facility procurement at Two Rivers East. Commercial production from Two Rivers East commenced with the completion of the facility in June 2025.

LIQUIDITY AND CAPITAL RESOURCES

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

($000s)	**September 30, 2025**	December 31, 2024	September 30, 2024
Current assets	**4,259**	11,579	49,905
Less:			
Current liabilities	**(56,325)**	(37,234)	(14,235)
Working capital	**(52,066)**	(25,655)	35,670
Add:			
Restricted cash deposits	**4,900**	4,900	10,001
Current portion of decommissioning obligations	**560**	2,118	1,593
Adjusted working capital (deficiency) (Capital management measure)	**(46,606)**	(18,637)	47,264

At September 30, 2025, the Company had an adjusted working capital deficiency of $46.6 million, which includes $44.0 million drawn under the Company's credit facilities. This is the result of debt drawn under its credit facilities in order to incur significant upfront capital costs associated with the Two Rivers East development project which commenced production from three of the nine previously drilled 5-19 pad wells in June 2025. The Company is now producing from four of the 5-19 wells and aims to have all nine wells on production by year-end. As noted below, subsequent to September 30, 2025, the Company entered into a $80.0 million credit facility with a Canadian chartered bank to replace its current credit facilities. A substantial portion of the additional funds available under the credit facility will be used to fund near-term capital to drill additional development wells on the 5-19 pad which will occur before the end of the year and expected to be brought on-stream in February 2026. The Company has chosen to moderate the pace of wells brought on-stream in response to natural gas prices at the Station 2 hub.

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.

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%. As at September 30, 2025, the Company had $5.4 million of outstanding letters of guarantee (December 31, 2024 - $5.4 million) 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. At September 30, 2025, the Company had $1.0 million of available capacity on the credit facility (December 31, 2024 - $45.0 million).

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.

As at September 30, 2025, $44.0 million has been drawn under its credit facilities (December 31, 2024 - $nil) and $0.2 million of unamortized debt issuance costs have been presented as a reduction to the balance drawn and will be amortized as finance expense over the remaining term.

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 and amounts associated with the pipeline obligation. At September 30, 2025, the adjusted working capital ratio covenant was waived and the Company was in compliance with the terms of its lending agreements.

Subsequent to September 30, 2025, the Company entered into a $80.0 million credit facility with a Canadian chartered bank to replace its current credit facilities described above and returned the letter of credit to the third party. The credit facility consists of a $10.0 million operating facility, a $50.0 million syndicated facility, and a $20.0 million term facility. The operating and syndicated facilities revolve for a 364 day period and will be subject to its next 364 day extension by May 31, 2026. If not extended, the new credit facility will cease to revolve, the margins thereunder will increase by 0.50%, and all outstanding advances will become repayable in one year from the extension date. The term facility matures May 31, 2026. The next scheduled borrowing base review of the new credit facility is scheduled on or before May 31, 2026.

Advances under the new credit facility are available by way of prime rate loans, with interest rates between 2.00% and 4.00% over the Canadian prime lending rate and CORRA loans which are subject to margins ranging from 3.00% to 5.00% depending upon the debt to EBITDA ratio of the Company. Standby fees are charged on the undrawn new credit facility at rates ranging from 0.75% to 1.25%. Until delivery of the Q1 2026 Compliance Certificate, the prime rate margin is fixed at 3.0%, the CORRA margin is fixed at 4.0% and standby fees are fixed at 1.0%. The term facility margins are based on the applicable margins for the operating and syndicated facilities plus 2.5% and must be drawn first before the operating and syndicated facilities. The new credit facility is secured by a $250.0 million fixed and floating charge debenture on the assets of the Company. The new credit facility includes the same adjusted working capital ratio covenant as the previous credit facilities described above.

Subsequent to September 30, 2025, the Company entered into a standby letter of credit facility agreement with a third party of up to $10.0 million USD ($13.9 million CDN) to guarantee letters of credit issued by the Company to other third parties. The fee on drawn amounts under the facility are 2.82%. This facility returned $4.9 million of restricted cash deposits to the Company and includes $5.2 million of capacity drawn that previously reduced the amount that could be borrowed under the original $7.0 million revolving operating demand loan credit facility which has now been replaced.

During the nine months ended September 30, 2025, the Company received $22.7 million from a midstream company to finance a pipeline connecting Coelacanth facilities to the midstream company's gathering system. Commencing June 2025, the Company is required to repay the principal amount over a five-year period at an interest rate of 12.0%.

With the substantial completion of the Two Rivers East development project, the resultant production from the 5-19 pad, and the expanded credit facility, management anticipates that the Company will continue to have adequate liquidity to meet its current and future obligations through a combination of its cash balance, cash flow, equity, and debt if required, pending commodity pricing, and operational performance. 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 financial liabilities, contractual obligations and commitments at September 30, 2025:

($000s)	Total	Less than One Year	One to Three Years	After Three Years
Accounts payable and accrued liabilities	7,787	7,787	-	-
Revolving credit facility	44,000	44,000	-	-
Other obligations - principal	22,836	3,914	9,243	9,679
Financing obligation payable	225	225	-	-
Decommissioning obligations	9,120	560	476	8,084
Operating commitments	1,668	233	594	841
Firm transportation agreements	175,507	5,092	16,145	154,270
Firm processing agreements	124,743	9,421	23,881	91,441
Total contractual obligations	385,886	71,232	50,339	264,315

Operating commitments include the non-lease variable components (operating expenses) of the head office lease inclusive of the extension to July 31, 2031.

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) through October 31, 2035 and then to Chicago through October 31, 2027.
- 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. Effective July 1, 2026, the commitment increases to 40.0 mmcf/d for the remaining term. Under the terms of the processing agreement, the Company can elect prior to November 1, 2026 to increase by any volume up to an additional 20.0 mmcf/d (60.0 mmcf/d total) for the remainder of the original term. As part of the arrangement, the midstream company funded the extension of their gathering system to connect to the Company's Two Rivers East project. During the nine months ended September 30, 2025, the Company received $22.7 million from the midstream company. Commencing June 2025, the Company is required to repay the principal amount over a five-year period at an 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. This balance is included in other obligations.

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)	**September 30, 2025**	November 18, 2025
Voting common shares	**533,029**	533,029
Warrants	**29,377**	29,377
Stock options	**22,354**	22,354
Restricted share units	**6,784**	6,784
Total	**591,544**	591,544

On June 30, 2025, 33.3 million warrants with an exercise price of $1.05 per warrant expired unexercised**.**

SUMMARY OF QUARTERLY RESULTS

	Q3 2025	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024	Q4 2023
Average Daily Production								
Oil and NGLs (bbls/d)	**1,464**	566	209	502	254	323	337	447
Natural gas (mcf/d)	**10,896**	3,861	3,311	3,490	3,450	3,724	3,934	2,858
Oil equivalent (boe/d)	**3,280**	1,210	761	1,084	829	944	993	923
($000s, except per share amounts)								
Oil and natural gas sales	**11,372**	4,828	2,666	4,544	2,362	3,164	3,666	4,204
Cash flow from (used in) operating activities	**4,712**	(1,826)	1,168	3,157	(3,730)	(480)	3,256	(404)
Per share basic and diluted [(2)]	**0.01**	(-)	-	0.01	(0.01)	(-)	0.01	(-)
Adjusted funds flow (used) [(1)]	**2,386**	(600)	(1,253)	382	(207)	262	1,078	1,750
Per share basic and diluted	**-**	(-)	(-)	-	(-)	-	-	-
Net loss	**(1,764)**	(3,464)	(3,617)	(2,903)	(2,464)	(2,329)	(1,201)	(750)
Per share basic and diluted	**(-)**	(0.01)	(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 increase in production, oil and natural gas sales, cash flow from operating activities, and adjusted funds flow in Q3 2025 was the result of the initiation of commercial production at Two Rivers East.

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. The decrease in Q1 2025 production from Q4 2024 was natural declines and the lack of testing new wells in Q1 2025. The increase in Q2 2025 production from Q1 2025 was the result of the initiation of commercial production at Two Rivers East. The decrease in cash flow from operations and adjusted funds flow and the increase in net loss in the first half of 2025 was mainly the result of increased interest expense, lower interest income, and payments on financing obligation. 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. Refer to note 3 of the audited financial statements for the year ended December 31, 2024 for the Company's material accounting policies.

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 September 30, 2025 was $44.0 million (December 31, 2024 - $nil). A 100 basis point increase or decrease in interest rates would have impacted net loss by approximately $0.2 million for the nine months ended September 30, 2025 (September 30, 2024 - $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. At September 30, 2025, the Company did not 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 September 30, 2025, $3.4 million (99%) of the Company's outstanding accounts receivable were current and $14 thousand (1%) were outstanding for more than 90 days. During the nine months ended September 30, 2025, the Company deemed $52 thousand of outstanding accounts receivable to be uncollectable (September 30, 2024 - $35 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 and future operations

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. Budgets and forecasting are subject to significant judgment and estimates relating to activity levels, future cash flows and timing thereof, and other factors which may not be within the control of the Company. In managing liquidity risk, the Company may rely on access to additional financing, including potential equity issuances and additional debt financing which depend on, among other things, the current commodity price environment, operating performance, and the Company's ability to access equity and debt capital markets. There is no assurance this capital will be available. In the event the Company requires additional funding and is not successful in obtaining additional funding or of obtaining funding on terms that are acceptable to the Company, this may impact the Company's ability to develop and maintain its oil and gas properties. 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 September 30, 2025, the Company had an adjusted working capital deficiency of $46.6 million which includes $44.0 million drawn under its credit facilities. During the nine months ended September 30, 2025, the Company received $22.7 million from a midstream company to finance a pipeline connecting Coelacanth facilities to the midstream company's gathering system. Commencing June 2025, this amount will be repaid over a five-year period at an interest rate of 12.0%. As at September 30, 2025, the Company had $5.4 million of outstanding letters of guarantee under the revolving operating demand loan credit facility thereby reducing the amount available from $7.0 million to $1.6 million, and $44.0 million drawn on the second credit facility reducing the amount available from $45.0 million to $1.0 million.

Subsequent to September 30, 2025, the Company entered into a $80.0 million credit facility with current lender to replace its previous credit facilities above. The credit facility consists of a $10.0 million operating facility, a $50.0 million syndicated facility, and a $20.0 million term facility. The operating and revolving syndicated facilities revolves for a 364 day period and will be subject to its next 364 day extension by May 31, 2026. If not extended, the new credit facility will cease to revolve, the margins thereunder will increase by 0.50%, and all outstanding advances will become repayable in one year from the extension date. The term facility matures May 31, 2026. The next scheduled borrowing base review of the new credit facility is scheduled on or before May 31, 2026. In addition to the credit facility, the Company also entered into standby letter of credit facility agreement with a third party of up to $10.0 million USD ($13.9 million CDN) to guarantee letters of credit issued by the Company to other third parties. The $10.0 million USD letter of credit facility allows the release of the $4.9 million restricted GIC into cash and also eliminates the reduction of availability of $5.4 million on the main credit facilities due to letters of credit being transferred to the standby letter of credit facility. This allows full use of the $80.0 million credit facility against bank debt of $39.1 million ($44.0 million drawn less $4.9 million released GIC) as at September 30, 2025. The Company notes that a substantial portion of the additional funds available under the new credit facility will be used to fund near-term capital costs associated with the drilling of three additional development wells on the 5-19 pad which will occur before the end of this year. The Company is now producing from four of the 5-19 wells and aims to have all nine wells on production by year-end.

There is considerable risk around the Company's ability to address these substantial liquidity uncertainties, however the Company believes it has the ability to manage the liquidity requirements of the business with the continued support of its lenders and the flexibility in its capital and operating activities. Specifically, with the substantial completion of the Two Rivers East development project, the resultant production from the 5-19 pad including the remaining wells anticipated to be on production by the end of the year, and the expanded credit facility, the Company anticipates 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, to maintain compliance with the covenants under its credit facilities, and to fund the other needs of the business for at least the next 12 months, pending commodity pricing, operational performance, and the addition of future reserves and the resulting potential for borrowing base increases. 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.

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	**Q3 2025**	Q2 2025	Q1 2025	Q4 2024	Q3 2024	Q2 2024	Q1 2024	Q4 2023
Condensate (bbls/d)	**46**	17	18	22	33	56	19	12
Other NGLs (bbls/d)	**92**	27	25	29	33	39	37	28
NGLs (bbls/d)	**138**	44	43	51	66	95	56	40
Tight oil (bbls/d)	**1,326**	522	166	451	188	228	281	407
Condensate (bbls/d)	**46**	17	18	22	33	56	19	12
Oil and condensate (bbls/d)	**1,372**	539	184	473	221	284	300	419
Other NGLs (bbls/d)	**92**	27	25	29	33	39	37	28
Oil and NGLs (bbls/d)	**1,464**	566	209	502	254	323	337	447
Shale gas (mcf/d)	**10,896**	3,861	3,311	3,490	3,450	3,724	3,934	2,858
Natural gas (mcf/d)	**10,896**	3,861	3,311	3,490	3,450	3,724	3,934	2,858
Oil equivalent (boe/d)	**3,280**	1,210	761	1,084	829	944	993	923

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. 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.