CANACOL ENERGY LTD.

MANAGEMENT'S DISCUSSION AND ANALYSIS
THREE MONTHS ENDED MARCH 31, 2025

FINANCIAL & OPERATING HIGHLIGHTS

(in United States dollars (tabular amounts in thousands) except as otherwise noted)

Financial	Three months ended March 31,		
	2025	2024	Change
Total revenues, net of royalties and transportation expense(1)	**72,735**	77,691	(6%)
Adjusted funds from operations(1)	**39,316**	42,226	(7%)
Per share – basic ($)(1)	**1.15**	1.24	(7%)
Per share – diluted ($)(1)	**1.15**	1.24	(7%)
Net income and comprehensive income	**31,801**	3,654	770%
Per share – basic ($)	**0.93**	0.11	745%
Per share – diluted ($)	**0.93**	0.11	745%
Cash flows provided by operating activities	**62,588**	54,719	14%
Per share – basic ($)(1)	**1.83**	1.60	14%
Per share – diluted ($)(1)	**1.83**	1.60	14%
Adjusted EBITDAX(1)	**56,268**	61,041	(8%)
Weighted average shares outstanding – basic	**34,120**	34,111	—%
Weighted average shares outstanding – diluted	**34,209**	34,111	—%
Net cash capital expenditures(1)	**50,477**	35,878	41%
	March 31, 2025	December 31, 2024	Change
Cash and cash equivalents	**79,139**	79,201	—%
Working capital surplus	**14,153**	45,524	(69%)
Total debt	**756,214**	762,313	(1%)
Total assets	**1,247,445**	1,215,777	3%
Common shares, end of period (000's)	**34,120**	34,120	—%

Operating	Three months ended March 31,		
	2025	2024	Change
Production			
Natural gas and LNG (Mcfpd)	**133,773**	154,043	(13%)
Colombia oil (bopd)	**1,227**	1,405	(13%)
Total (boepd)	**24,696**	28,430	(13%)
Realized contractual sales			
Natural gas and LNG (Mcfpd)	**128,693**	150,421	(14%)
Colombia oil (bopd)	**1,195**	1,389	(14%)
Total (boepd)	**23,773**	27,779	(14%)
Operating netbacks(1)			
Natural gas and LNG ($/Mcf)	**5.48**	4.90	12%
Colombia oil ($/bbl)	**13.76**	20.15	(32%)
Corporate ($/boe)	**30.36**	27.51	10%

(1) Non-IFRS measures – see "Non-IFRS Measures" section within this MD&A.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Canacol Energy Ltd. and its subsidiaries ("Canacol" or the "Corporation") are primarily engaged in natural gas exploration and development activities in Colombia. The Corporation's head office is located at 2000, 215 - 9th Avenue SW, Calgary, Alberta, T2P 1K3, Canada. The Corporation's shares are traded on the Toronto Stock Exchange (the "TSX") under the symbol CNE, the OTCQX in the United States of America under the symbol CNNEF, the Bolsa de Valores de Colombia under the symbol CNEC and the Bolsa Mexicana de Valores under the symbol CNEN.

Advisories

The following management's discussion and analysis ("MD&A") is dated May 7, 2025 and is the Corporation's explanation of its financial performance for the period covered by the unaudited interim condensed consolidated financial statements for the three months ended March 31, 2025 ("the financial statements"), along with an analysis of the Corporation's financial position. Comments relate to and should be read in conjunction with the financial statements, and the audited consolidated financial statement and MD&A for the year ended December 31, 2024. The financial statements were prepared by management in accordance with IFRS Accounting Standards as issued by the International Accounting Standards Board ("IFRS Accounting Standards"), and all amounts herein are expressed in United States dollars ("USD"), unless otherwise noted, and all tabular amounts are expressed in thousands of USD, except per share amounts or as otherwise noted. Additional information for the Corporation, including the Annual Information Form, may be found on SEDAR+ at www.sedarplus.ca.

Forward-Looking Statements – *Certain information set forth in this document contains forward-looking statements. All statements other than historical facts contained herein are forward-looking statements, including, without limitation, statements regarding the future financial position, business strategy, production rates, and plans and objectives of or involving the Corporation. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond the Corporation's control, including the impact of general economic conditions, industry conditions, governmental regulation, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and the ability to access sufficient capital from internal and external sources. In particular, with respect to forward-looking comments in this MD&A, readers are cautioned that there can be no assurance that the Corporation will complete its planned capital projects on schedule, or that natural gas and petroleum production will result from such capital projects, or that additional natural gas sales contracts will be secured, or that hydrocarbon-based royalties assessed will remain consistent, or that royalties will continue to be applied on a sliding-scale basis as production increases on any one block, or that there will be no penalties on the termination of the Medellin gas sales contract. The Corporation's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits the Corporation will derive therefrom.*

In addition to historical information, this MD&A contains forward-looking statements that are generally identifiable as any statements that express, or involve discussions as to, expectations, beliefs, plans, objectives, assumptions or future events of performance (often, but not always, through the use of words or phrases such as "will likely result," "expected," "is anticipated," "believes," "estimated," "intends," "plans," "projection" and "outlook"). These statements are not historical facts and may be forward-looking and may involve estimates, assumptions and uncertainties which could cause actual results or outcomes to differ materially from those expressed in such forward-looking statements. Actual results achieved during the forecast period will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: general economic, market and business conditions; fluctuations in natural gas, LNG and oil prices; the results of exploration and development drilling and related activities; fluctuations in foreign currency exchange rates; the uncertainty of reserve estimates; changes in environmental and other regulations; and risks associated with natural gas and oil operations, many of which are beyond the control of the Corporation and are subject to a high degree of uncertainty. Accordingly, there is no representation by the Corporation that actual results achieved during the forecast period will be the same in whole or in part as those forecasted. Except to the extent required by law, the Corporation assumes no obligation to publicly update or revise any forward-looking statements made in this MD&A or otherwise, whether as a result of new information, future events or otherwise. All subsequent forward-looking statements, whether written or oral, attributable to the Corporation or persons acting on the Corporation's behalf, are qualified in their entirety by these cautionary statements.

Readers are further cautioned not to place undue reliance on any forward-looking information or statements.

Non-IFRS Measures – *Some of the benchmarks the Corporation uses to evaluate its performance are adjusted funds from operations, adjusted EBITDAX, and net cash capital expenditures, which are measures not defined in IFRS Accounting Standards. Adjusted funds from operations represents cash flow provided by operating activities before the settlement of decommissioning obligations and changes in non-cash working capital, adjusted for non-recurring charges. Adjusted EBITDAX is calculated on a rolling 12-month basis and is defined as net income (loss) and comprehensive income (loss) adjusted for interest, income taxes, depreciation, depletion, amortization, pre-license costs and other similar non-recurring or non-cash charges. Net cash capital expenditures represents capital expenditures net of dispositions, excluding non-cash costs and adjustments such as the addition of right-of-use leased assets and change in decommissioning obligations. The Corporation considers these measures as key measures to demonstrate its ability to generate the cash flow necessary to fund future growth through capital investment, pay dividend and repay its debt. These measures should not be considered as an alternative to, or more meaningful than, cash provided by operating activities, or net income (loss) and comprehensive income (loss), or capital expenditures as determined in accordance with IFRS Accounting Standards as an indicator of the Corporation's performance. The Corporation's determination of these measures may not be comparable to that reported by other companies.*

The Corporation also presents adjusted funds from operations per share, whereby per share amounts are calculated using the weighted-average shares outstanding consistent with the calculation of net income (loss) and comprehensive income (loss) per share.

The following table reconciles the Corporation's cash provided by operating activities to adjusted funds from operations:

	Three months ended March 31,	
	2025	2024
Cash flows provided by operating activities	**$ 62,588**	$ 54,719
Changes in non-cash working capital	**(23,272)**	(13,194)
Settlement of decommissioning obligations	**—**	701
Adjusted funds from operations	**$ 39,316**	$ 42,226

The following table reconciles the Corporation's net income (loss) and comprehensive income (loss) to adjusted EBITDAX:

	2024			**2025**	
	Q2	**Q3**	**Q4**	**Q1**	**Rolling**
Net income (loss) and comprehensive income (loss)	$ (21,298)	$ 10,346	$ (25,434)	$ 31,801	$ (4,585)
(+) Interest expense	14,270	15,395	14,682	14,557	58,904
(+) Income tax expense (recovery)	53,789	31,473	51,806	(4,918)	132,150
(+) Amortization of debt fees	2,014	2,175	2,759	2,726	9,674
(+) Depletion and depreciation	19,433	20,254	23,071	17,259	80,017
(+) Exploration impairment	—	—	2,252	—	2,252
(+) Pre-license costs	185	109	437	70	801
(+) Unrealized foreign exchange loss (gain)	(550)	2,825	4,073	(4,111)	2,237
(+/-) Other non-cash or non-recurring items[1]	5,344	3,267	2,408	(1,116)	9,903
Adjusted EBITDAX	**$ 73,187**	**$ 85,844**	**$ 76,054**	**$ 56,268**	**$ 291,353**

(1) Primarily comprised of gain on Senior Note buyback, equity investment income, stock based compensation expense, accretion expense, and write-off of deposits.

		2023		2024	
		Q2	Q3	Q4	Q1	Rolling
Net income (loss) and comprehensive income (loss)	$ 39,990	$ (524)	$ 29,897	$ 3,654	$ 73,017
(+) Interest expense	12,182	12,001	12,998	13,721	50,902
(+) Income tax expense (recovery)	(14,500)	(5,596)	(14,076)	17,718	(16,454)
(+) Amortization of debt fees	1,997	2,016	2,021	2,009	8,043
(+) Depletion and depreciation	19,249	17,619	20,086	19,026	75,980
(+) Impairment of long lived assets	—	32,604	2,750	—	35,354
(+) Pre-license costs	198	270	327	189	984
(+) Unrealized foreign exchange loss (gain)	245	1,354	(2,316)	561	(156)
(+/-) Other non-cash or non-recurring items(1)	1,293	2,359	1,457	4,163	9,272
Adjusted EBITDAX	**$ 60,654**	**$ 62,103**	**$ 53,144**	**$ 61,041**	**$ 236,942**

(1) Primarily comprised of equity investment income, stock based compensation expense, and accretion expense.

In addition to the above, management uses the operating netback measure. Operating netback is a benchmark common in the oil and gas industry and is calculated as revenue, net of transportation expense, less royalties, less operating expenses, calculated on a per unit basis of sales volumes. Operating netback is an important measure in evaluating operational performance as it demonstrates profitability relative to current commodity prices.

Operating netback as presented does not have any standardized meaning prescribed by IFRS Accounting Standards and therefore may not be comparable with the calculation of similar measures for other entities.

The term "boe" is used in this MD&A. Boe may be misleading, particularly if used in isolation. A boe conversion ratio of cubic feet of natural gas to barrels of oil equivalent is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. In this MD&A, boe is expressed using the Colombian conversion standard of 5.7 Mcf: 1 bbl required by the Ministry of Mines and Energy of Colombia. Natural gas and LNG volumes per day are expressed in thousand cubic feet per day ("Mcfpd") or million cubic feet per day ("MMcfpd") throughout this MD&A.

Three Months Ended March 31, 2025 Financial and Operating Highlights

- The Corporation's natural gas and liquefied natural gas ("LNG") operating netback increased 12% to $5.48 per Mcf for the three months ended March 31, 2025 compared to $4.90 per Mcf for the same period in 2024. The increase is due to an increase in average sales prices, net of transportation expenses.
- Adjusted EBITDAX decreased 8% to $56.3 million for the three months ended March 31, 2025, compared to $61.0 million for the same period in 2024. The decrease is mainly due to a decrease in realized contractual natural gas and LNG sales volumes, offset by an increase of natural gas and LNG operating netback.
- Adjusted funds from operations decreased 7% to $39.3 million for the three months ended March 31, 2025, compared to $42.2 million for the same period in 2024 mainly due to a decrease in EBITDAX.
- Total revenues, net of royalties and transportation expenses for the three months ended March 31, 2025 decreased 6% to $72.7 million compared to $77.7 million for the same period in 2024, mainly due to a decrease in realized natural gas and LNG sales volumes, offset by an increase in average sales price, net of transportation expenses of $7.23 per Mcf for the three months ended March 31, 2025, compared to $6.60 per Mcf for the same period in 2024.
- Realized contractual natural gas sales volume decreased 14% to 128.7 MMcfpd for the three months ended March 31, 2025, compared to 150.4 MMcfpd for the same period in 2024.
- The Corporation realized net income of $31.8 million for the three months ended March 31, 2025 , compared to net income of $3.7 million for the same period in 2024. The increase in net income for the three months ended March 31, 2025 is the result of recognizing a non-cash deferred income tax recovery of $19.5 million for the three months ended March 31, 2025 as compared to a non-cash deferred income tax expense of $0.5 million in 2024, offset by a decrease in EBITDAX.
- Net cash capital expenditures for the three months ended March 31, 2025 were $50.5 million compared to $35.9 million for the same period in 2024. The increase is due to increased spending on drilling, completion, testing, and workovers.
- As at March 31, 2025, the Corporation had $79.1 million in cash and cash equivalents and $14.2 million in working capital.

Results of Operations

For the three months ended March 31, 2025, the Corporation's production primarily consisted of natural gas from the Esperanza, VIM-5, VIM-21 and VIM-33 blocks located in the Lower Magdalena Valley basin in Colombia. The Corporation's production also included crude oil from its Rancho Hermoso block in Colombia ("Colombia oil"). The Corporation's LNG production was less than one percent of total natural gas and LNG production and, therefore, the results have been combined as "Natural gas and LNG".

On November 2, 2024, the Corporation spud the Natilla-2 exploration well located on its SSJN-7 block, targeting a large natural gas prospect with primary and secondary targets within the Cienaga de Oro ("CDO") reservoir and overlying middle Porquero formations, respectively. The well encountered drilling difficulties at a depth of 13,631 feet measured depth ("ft MD") within the middle Porquero formation. The Natilla-2 well was sidetracked and reached a total depth of 15,050 ft TVD near the base of the Porquero formation, which is the planned intermediate casing point of the well situated just above the underlying CDO primary target. Drilling through the Porquero took longer than anticipated due to high pressure and wellbore issues. The well encountered an approximately 550 ft TVD gross section of interbedded sandstone and shales within the Porquero with good reservoir quality as indicated by sonic and resistivity logs collected while drilling. Formation pressures across this section of the Porquero ranged from 12,500 – 13,500 psi based on the PWD (Pressure While Drilling) tool, indicating gas at very high pressure, and very high mud weights of up to 18.8 pounds per gallon while drilling were required to prevent the influx of gas into the wellbore. Despite the heavy mud weights used while drilling through this section of the Porquero, total measured gas confirmed that the sandstones are gas charged. While running casing to isolate the Porquero, difficulties associated with high pressures were encountered and the well was sidetracked and reached a total depth of 15,250 ft at the base of the Porquero. The well subsequently encountered difficulties while running casing and has been temporarily suspended pending delivery of new equipment, resumption of operations and continuing to drill to the primary CDO target to a total planned depth of 16,510 ft TVD. Upon completion of drilling, open hole and cased hole logs will be run across both the CDO and Porquero formations, and production tests will subsequently be conducted across any potential gas producing intervals.

On December 21, 2024, the Corporation spud the Clarinete-11 development well located on its VIM-5 block. The Clarinete-11 well encountered 205 feet true vertical depth ("ft TVD") of net gas pay within the CDO reservoir. The Clarinete-11 well was tied in and put on production.

On January 19, 2025, the Corporation spud the Lulo-3 development well located on its VIM-21 block. The Lulo-3 well encountered 100 ft TVD of net gas pay within the CDO reservoir. The Lulo-3 well was tied in and put on production.

On January 26, 2025, the Corporation spud the Siku-2 development well located on its VIM-5 block. The Siku-2 well encountered 260 ft TVD of net gas pay within the CDO reservoir. The Siku-2 well was tied in and put on production.

On February 18, 2025, the Corporation spud the Fresa-3 appraisal well located on its VIM-21 block. The Fresa-3 well encountered 93 ft TVD of net gas pay within the CDO reservoir. The Fresa-3 well was tied in and put on production.

On February 27, 2025, the Corporation spud the Chibigui-1 exploration well located on its VIM-21 block. The Chibigui-1 well encountered 59 ft TVD of net gas pay within the CDO reservoir. Non-commercial amount of gas was recovered during testing and the well is currently suspended.

Average Daily Production and Realized Contractual Sales Volumes

Production and sales volumes in this MD&A are reported before royalties.

	Three months ended March 31,		
	2025	2024	Change
Natural Gas and LNG (Mcfpd)			
Natural gas and LNG production	**133,773**	154,043	(13%)
Field consumption	**(5,080)**	(3,883)	31%
Natural gas and LNG sales	**128,693**	150,160	(14%)
Take-or-pay volumes (2)	**—**	261	(100%)
Realized contractual natural gas and LNG sales	**128,693**	150,421	(14%)
Colombia Oil (bopd)			
Crude oil production	**1,227**	1,405	(13%)
Inventory movements and other	**(32)**	(16)	100%
Colombia oil sales	**1,195**	1,389	(14%)
Corporate (boepd)			
Natural gas and LNG production	**23,469**	27,025	(13%)
Colombia oil production	**1,227**	1,405	(13%)
Total production	**24,696**	28,430	(13%)
Field consumption and inventory	**(923)**	(697)	32%
Total corporate sales	**23,773**	27,733	(14%)
Take-or-pay volumes (2)	**—**	46	(100%)
Total realized contractual sales	**23,773**	27,779	(14%)

The Corporation has three types of natural gas and LNG sales:

1) *Natural Gas and LNG sales* - represents natural gas and LNG production less a typically small amount of gas volume that is consumed at the field level;
2) *Take-or-pay income* - represents the portion of natural gas and LNG sales nominations by the Corporation's off-takers that do not get delivered, due to the off-taker's inability to accept such natural gas and for which the off-takers have no recourse or legal right to delivery at a later date. As such, they are recorded as revenue in the period; and
3) *Undelivered natural gas and LNG nomination*s - represents the portion of undelivered natural gas and LNG sales nominations for which the off-takers have a legal right to take delivery at a later date, for a fixed period of time ("make-up rights"). These nominations are paid for at the time, alongside natural gas and LNG sales and take-or-pay income, and as such are included in deferred income for the period. The Corporation recognizes revenues associated with such make-up rights ("settlements") at the earlier of: a)when the make-up volume is delivered, b) the make-up right expires, or c) when it is determined that the likelihood that the off-taker will utilize the make-up right is remote.

Realized contractual natural gas and LNG sales for the three months ended March 31, 2025 averaged 128.7 MMcfpd. Realized contractual sales is defined as natural gas and LNG produced and sold plus income received from nominated take-or-pay contracts without the actual delivery of natural gas or LNG and the expiry of the customers' rights to take the deliveries.

The 14% decrease in realized contractual natural gas and LNG sales for the three months ended March 31, 2025, compared to the same period in 2024 is mainly due to natural decline, offset by exploration successes.

The 14% decrease in Colombia oil sales for the three months ended March 31, 2025, compared to the same period in 2024 is mainly due to natural decline.

Revenues, Net of Royalties and Transportation Expenses

	Three months ended March 31,			
	2025		2024	Change
Natural Gas and LNG				
Natural gas and LNG revenues	**$**	**87,006**	$ 95,820	(9%)
Transportation expenses		**(3,233)**	(5,693)	(43%)
Revenues, net of transportation expenses		**83,773**	90,127	(7%)
Royalties		**(14,439)**	(17,031)	(15%)
Revenues, net of royalties and transportation expenses	**$**	**69,334**	$ 73,096	(5%)
Colombia Oil				
Crude oil revenues	**$**	**2,733**	$ 3,895	(30%)
Transportation expenses		**(23)**	(18)	28%
Revenues, net of transportation expenses		**2,710**	3,877	(30%)
Royalties		**(65)**	(144)	(55%)
Revenues, net of royalties and transportation expenses	**$**	**2,645**	$ 3,733	(29%)
Corporate				
Natural gas and LNG revenues	**$**	**87,006**	$ 95,820	(9%)
Crude oil revenues		**2,733**	3,895	(30%)
Total revenues		**89,739**	99,715	(10%)
Royalties		**(14,504)**	(17,175)	(16%)
Natural gas, LNG and crude oil production revenues, net of royalties		**75,235**	82,540	(9%)
Power generation standby revenue		**756**	753	—%
Take-or-pay natural gas income		**—**	109	n/a
Total revenues, net of royalties, as reported		**75,991**	83,402	(9%)
Transportation expenses		**(3,256)**	(5,711)	(43%)
Total revenues, net of royalties and transportation expenses	**$**	**72,735**	$ 77,691	(6%)

Natural Gas and LNG Sales and Power Generation Standby Revenue

Natural gas and LNG revenues, net of transportation expenses for the three months ended March 31, 2025 decreased 7% to $83.8 million compared to $90.1 million for the same period in 2024, due to lower sales volumes, offset by higher average sales price, net of transportation expenses.

Colombia oil revenues, net of transportation expenses for the three months ended March 31, 2025 decreased 30% compared to the same period in 2024, mainly due to lower average sales price and lower sales volumes.

During the three months ended March 31, 2025 and 2024, the Corporation realized power generation standby revenue of $0.8 million for its commitment to supply natural gas to a Colombian power generation plant owned by Termoelectrica el Tesorito S.A.S. ESP ("Tesorito"). The power generation standby revenue is earned on a daily basis, regardless of whether natural gas is actually delivered.

As at March 31, 2025, the Corporation had deferred income of $20.5 million (December 31, 2024 - $18.5 million) which was related to undelivered natural gas and LNG sales nominations that were paid for or accrued in accounts receivable, for which the off-takers have a legal right to take delivery at a later date, at which point they will be recognized as revenue. Should the off-taker not accept delivery within the allotted period, the Corporation will recognize the corresponding nominations as take-or-pay income as explained on page 7 of this MD&A.

Natural Gas Transportation Expenses

The Corporation either sells its natural gas at its Jobo gas plant gate (whereby the off-taker incurs the transportation expenses, and as such Canacol does not recognize a transportation expense), or delivers its natural gas to the off-takers' locations (whereby Canacol pays and recognizes the transportation expenses directly). In the latter case, the Corporation's transportation expenses on such contracts are compensated by higher gross sales prices, resulting in average realized sales prices (net of transportation) being consistent with the Corporation's realized price in which the off-taker incurs the transportation expense. The blend of these two types of delivery options varies from contract to contract and from quarter to quarter, hence the Corporation refers to an average net realized sales price, which in either case, is net of any transportation costs, regardless of which party incurs the transportation expense. Natural gas transportation expenses decreased 43% for the three months ended March 31, 2025 compared to the same period in 2024, due to a decrease in natural gas sales subject to transportation expenses, as described above.

Natural Gas Royalties

	Three months ended March 31,		
	2025	2024	Change
Natural Gas			
Esperanza royalties	**$ 831**	$ 796	4%
VIM-5 royalties	**11,778**	14,852	(21%)
VIM-21 royalties	**1,784**	1,383	29%
VIM-33 royalties	**46**	—	n/a
Royalty expense	**$ 14,439**	$ 17,031	(15%)
Natural Gas Royalty Rates			
Esperanza	**7.9%**	9.1%	(13%)
VIM-5	**22.1%**	22.5%	(2%)
VIM-21	**9.3%**	9.6%	(3%)
VIM-33	**7.6%**	—%	n/a
Natural gas royalty rate	**17.2%**	18.9%	(9%)

The Corporation's natural gas royalties are generally at a rate of 6.4%, until net field production reaches 5,000 boepd, at which point the royalty rates increase on a sliding scale up to a 20% maximum rate at 600,000 boepd field production. The Corporation's Esperanza and VIM-5 natural gas production is subject to an additional overriding royalty of 2% to 4%. The Corporation's VIM-5, VIM-21 and VIM-33 natural gas production is subject to additional x-factor royalty rates of 13%, 3% and 1%, respectively.

Average Benchmark and Realized Sales Prices, Net of Transportation

	Three months ended March 31,		
	2025	2024	Change
Average Benchmark Prices			
Henry Hub ($/MMBtu)	**$ 4.14**	$ 1.75	137%
Alberta Energy Company ("AECO") ($/MMBtu)	**$ 1.50**	$ 1.29	16%
Brent ($/bbl)	**$ 71.47**	$ 84.67	(16%)
Average Sales Prices, Net of Transportation			
Natural gas and LNG ($/Mcf)	**$ 7.23**	$ 6.60	10%
Colombia oil ($/bbl)	**$ 25.20**	$ 30.67	(18%)
Corporate average ($/boe)	**$ 40.42**	$ 37.25	9%

The sales prices of the Corporation's natural gas sales contracts are largely fixed, with a portion of its portfolio sold on the spot (interruptible) market. The Corporation's transportation expenses associated with the spot sales are typically compensated by higher gross sales prices, resulting in realized sales prices, net of transportation that are consistent with the Corporation's firm fixed-priced contracts.

Average natural gas and LNG sales prices, net of transportation increased 10% to $7.23 per Mcf for the three months ended March 31, 2025, compared to $6.60 per Mcf for the same period in 2024. The increase in average natural gas and LNG sales prices, net of transportation for the three months ended March 31, 2025 is mainly due to an increase in interruptible prices as a result of tight natural gas supply in Colombia.

The 18% decrease in average crude oil prices for the three months ended March 31, 2025, compared to the same period in 2024 is due to a higher portion of total oil production sold under tariff agreement.

Operating Expenses

	Three months ended March 31,		
	2025	2024	Change
Natural gas and LNG	**$ 5,848**	$ 6,214	(6%)
Colombia oil	**1,166**	1,186	(2%)
Total operating expenses	**$ 7,014**	$ 7,400	(5%)
Natural gas and LNG ($/Mcf)	**$ 0.50**	$ 0.45	11%
Colombia oil ($/bbl)	**$ 10.84**	$ 9.38	16%
Corporate ($/boe)	**$ 3.28**	$ 2.93	12%

Natural gas and LNG operating expenses decreased 6% to $5.8 million for the three months ended March 31, 2025 compared to $6.2 million for the same period in 2024. The decrease in natural gas and LNG operating expenses for the three months ended March 31, 2025 is due to a decrease in maintenance activities, which are postponed to later in 2025, offset by an increase in environmental costs, increase in insurance premium, and inflation.

Colombia oil operating expenses decreased 2% for the three months ended March 31, 2025, compared to the same period in 2024, mainly due to a decrease in equipment rental costs, offset by an increase in maintenance activities and inflation.

Operating Netbacks

	Three months ended March 31,		
$/Mcf	**2025**	2024	Change
Natural Gas and LNG			
Revenue, net of transportation expense(1)	**$ 7.23**	$ 6.60	10%
Royalties	**(1.25)**	(1.25)	—%
Operating expenses(2)	**(0.50)**	(0.45)	11%
Operating netback	**$ 5.48**	$ 4.90	12%

	Three months ended March 31,		
$/bbl	**2025**	2024	Change
Colombia oil			
Revenue, net of transportation expense(1)	**$ 25.20**	$ 30.67	(18%)
Royalties	**(0.60)**	(1.14)	(47%)
Operating expenses(2)	**(10.84)**	(9.38)	16%
Operating netback	**$ 13.76**	$ 20.15	(32%)

(1) Refer to the "Average Benchmark and Realized Sales Prices, Net of Transportation" of this MD&A for more information.

(2) Refer to the "Operating Expenses" section of this MD&A for more information.

$/boe	2025	Three months ended March 31, 2024	Change
Corporate			
Revenue, net of transportation expense	**$ 40.42**	$ 37.25	9%
Royalties	**(6.78)**	(6.81)	—%
Operating expenses	**(3.28)**	(2.93)	12%
Operating netback	**$ 30.36**	$ 27.51	10%

General and Administrative Expenses

	2025	Three months ended March 31, 2024	Change
Gross costs	**$ 9,719**	$ 9,666	1%
Less: capitalized amounts	**(2,713)**	(1,535)	77%
General and administrative expenses	**$ 7,006**	$ 8,131	(14%)
$/boe	**$ 3.27**	$ 3.22	2%

General and administrative ("G&A") gross costs increased 1% for the three months ended March 31, 2025, compared to the same period in 2024, mainly due to inflation, offset by the Corporation's continued cost-cutting initiatives.

Net Finance Expense

	2025	Three months ended March 31, 2024	Change
Net financing expense paid	**$ 13,486**	$ 13,328	1%
Non-cash net financing expenses	**3,795**	2,728	39%
Net finance expense	**$ 17,281**	$ 16,056	8%

Net finance expense increased 8% for the three months ended March 31, 2025 compared to the same period in 2024 mainly as a result of an increase in total debt and an increase in non-cash financing expenses, offset by a decrease in benchmark interest rates.

Stock-Based Compensation Expense

	2025	Three months ended March 31, 2024	Change
Equity-settled unit expense	**$ 46**	$ 376	(88%)
Cash-settled unit expense	**391**	(324)	n/a
Stock-based compensation	**$ 437**	$ 52	740%

Equity-settled unit expense is related to stock options, the fair value of which are amortized and expensed over their respective vesting periods. Stock options are settled in shares when exercised. Equity-settled unit expense decreased by 88% for the three months ended March 31, 2025 compared to the same period in 2024, as no new stock options were granted to employees during the three months ended March 31, 2025 .

Cash-settled unit expense is related to restricted share units ("RSUs"), performance share units ("PSUs") and deferred share units ("DSUs"), the fair value of which are amortized and expensed over their respective vesting periods and revalued at each reporting date based on the Corporation's share price. RSUs, PSUs and DSUs are expected to be settled in cash. The Corporation realized a cash-settled unit expense of $0.4 million for the three months ended March 31, 2025, compared to a recovery in the same period in 2024. The recovery in the three months ended March 31, 2024 was as a result of a decrease in Canacol's share price.

Depletion and Depreciation Expense

	Three months ended March 31,		
	2025	2024	Change
Depletion and depreciation expense	**$ 17,259**	$ 19,026	(9%)
$/boe	**$ 8.07**	$ 7.54	7%

Depletion and depreciation expense decreased 9% for the three months ended March 31, 2025, compared to the same period in 2024 due to lower production. Depletion and depreciation expense per boe increased 7% for the three months ended March 31, 2025, compared to the same period in 2024 as a result of higher depletion rate.

Income Tax Expense

	Three months ended March 31,		
	2025	2024	Change
Current income tax expense	**$ 14,598**	$ 17,183	(15%)
Deferred income tax expense (recovery)	**(19,516)**	535	n/a
Income tax expense (recovery)	**$ (4,918)**	$ 17,718	n/a

The Corporation's pre-tax income was subject to the Colombian statutory income tax rate of 35% for the three months ended March 31, 2025 . In addition, taxable income generated from business relating to crude oil was subject to an additional 10% surtax.

Current income tax expense for the three months ended March 31, 2025 decreased by 15% compared to the same period in 2024. This is due to an 8% decrease in EBITDA, and the result of the corporate restructuring process that began in Q4 2022 to enhance operational alignment and create a more cost-effective structure.

For the three months ended March 31, 2025, the Corporation recognized a deferred tax recovery of $19.5 million, mainly as a result of the foreign exchange impact on the Corporation's unused tax losses and capital pools.

Income Tax Cash Payments

	Three months ended March 31,		
	2025	2024	Change
Income tax payments and installments	**$ 14,636**	$ 13,578	8%
Withholding tax	**$ 9,418**	$ 6,396	47 %

Capital Expenditures

	Three months ended March 31, 2025	2024
Land, seismic, EIAs and communities	**$ 491**	$ 3,014
Drilling, completion, testing and workovers	**42,843**	28,213
Facilities, equipment and infrastructures	**6,072**	6,859
Warehouse inventory, corporate assets and other	**(1,642)**	(3,685)
Capitalized G&A	**2,713**	1,535
Proceeds on disposition	**—**	(58)
Net cash capital expenditures	**50,477**	35,878
Non-cash costs and adjustments:		
Right-of-Use leased assets	**66**	3,000
Disposition	**—**	51
Change in decommissioning obligations and other	**(1,165)**	(954)
Net capital expenditures	**$ 49,378**	$ 37,975
Net capital expenditures recorded as:		
Expenditures on exploration and evaluation assets	**$ 20,189**	$ 12,965
Expenditures on property, plant and equipment	**29,189**	25,017
Disposition	**—**	(7)
Net capital expenditures	**$ 49,378**	$ 37,975

Net capital expenditures for the three months ended March 31, 2025 are primarily related to:

- Natilla-2ST exploration well;
- Fresa-3 appraisal well;
- Siku-2 development well;
- Lulo-3 development well;
- Chibigui-1 exploration well;
- Compression facilities and workovers related costs at the VIM-5, and VIM-21 blocks; and
- Land, communities and other costs at the Esperanza, VIM-5, VIM-21, and SSJN-7 blocks.

Liquidity and Capital Resources

Capital Management

The Corporation's policy is to maintain a strong capital base in order to provide flexibility in the future development of the business and maintain investor, creditor and market confidence. The Corporation manages its capital structure and makes adjustments in response to changes in economic conditions and the risk characteristics of the underlying assets. The Corporation considers its capital structure to include share capital, long-term debt, lease obligations and working capital, defined as current assets less current liabilities excluding the current portion of long-term obligations. In order to maintain or adjust the capital structure, from time to time the Corporation may issue or repurchase common shares or other securities, sell assets or adjust its capital spending to manage current and projected debt levels.

The Corporation monitors leverage and adjusts its capital structure based on its net debt level. Net debt is defined as the principal amount of its outstanding long-term obligations less working capital, as defined above. In order to facilitate the management of its net debt, the Corporation prepares annual budgets, which are updated as necessary depending on varying factors including current and forecast commodity prices, changes in capital structure, execution of the Corporation's business plan and general industry conditions. The annual budget is approved by the Board of Directors and updates are prepared and reviewed as required.

Senior Notes

On November 24, 2021, the Corporation completed a private offering of senior unsecured notes in the aggregate principal amount of $500 million ("Senior Notes"). The Senior Notes pay interest semi-annually at a fixed rate of 5.75% per annum, and mature in 2028 unless earlier redeemed or repurchased in accordance with their terms. The Senior Notes are fully and unconditionally guaranteed by certain subsidiaries of Canacol.

On March 26, 2025, the Corporation repurchased $5.0 million of Senior Notes for $2.7 million of cash. The repurchased Senior Notes were subsequently cancelled in April 2025.

Revolving Credit Facility

On February 17, 2023, the Corporation entered into a $200 million senior unsecured revolving credit facility ("RCF") with a syndicate of banks. The RCF bears an annual interest rate of SOFR + 4.5%, has a four-year term, and the Corporation is able to repay/redraw the RCF at any time within the term without penalty. Any undrawn amounts are subject to a commitment fee equal to 30% of the 4.5% interest margin throughout the availability period. The RCF is not subject to typical periodic redeterminations. The amount drawn and outstanding as at March 31, 2025 was $200 million.

Senior Term Loan Facility

On September 3, 2024, the Corporation entered into a $75 million senior secured term loan facility (the "Term Loan") with Macquarie Group ("Macquarie"). The initial draw was $50 million, with a further commitment of $25 million available for a 12-month period should certain production metrics be met. The Term Loan bears an annual interest rate of SOFR + 10% on drawn amounts and 2.4% on undrawn amounts. The Term Loan is set to amortize over four equal quarterly installments starting on December 3, 2025. No prepayments may be made during the first 12 months. The Term Loan is secured by all material assets of the Corporation.

In connection with the Term Loan, 1,888,448 common share purchase warrants (the "Warrants") were issued to Macquarie, with each Warrant entitling Macquarie to purchase one common share of the Corporation at C$3.80. The Warrants will expire three years after the date of issuance. The Warrants were valued at $1.6 million ($1.4 million net of fees) at inception and were recognized under Other Reserves as at March 31, 2025.

Financial Covenants

The Corporation's Senior Notes, RCF, and Term Loan include various covenants relating to maximum leverage, minimum interest coverage, minimum liquidity requirements, minimum reserves value, indebtedness, operations, investments, assets sales, capital expenditures and other standard operating business covenants.

The Corporation's financial covenants include:

a) Consolidated Leverage Ratio: a maximum consolidated total debt, less cash and cash equivalents, to 12-month trailing adjusted EBITDAX ratio of 3.25 : 1.00 (incurrence) or 3.50 : 1:00 (maintenance);

b) Consolidated Interest Coverage Ratio: a minimum 12-month trailing adjusted EBITDAX, to 12-month trailing interest expense, excluding non-cash expenses ratio of 2.50 : 1.00; and

c) Consolidated Current Ratio: a minimum adjusted current assets, to adjusted current liabilities ratio of 1.00 : 1.00;

d) Consolidated Asset Coverage Ratio: a minimum aggregate net present value of proved developed producing reserves before tax (discounted at 10%) as at the most recent reserves report date ("PDP PV10 Value"), to the principal drawn and outstanding on the Term Loan ratio of 2.50 to 1.00.

As at March 31, 2025, the Corporation was in compliance with the covenants.

	March 31, 2025	December 31, 2024
Senior Notes - principal (5.75%)	**$ 495,000**	$ 500,000
RCF (SOFR + 4.5%)(1)	**200,000**	200,000
Term Loan (SOFR + 10%)(1)	**50,000**	50,000
Lease obligations	**11,214**	12,313
Total debt	**756,214**	762,313
Working capital surplus	**(14,153)**	(45,524)
Net debt	**$ 742,061**	$ 716,789

(1) The SOFR rate for the three months ended March 31, 2025 was 4.33%.

The Consolidated Leverage Ratio is calculated as follows:

	March 31, 2025	December 31, 2024
Total debt	**$ 756,214**	$ 762,313
Less: cash and cash equivalents	**(79,139)**	(79,201)
Net debt for covenant purposes	**$ 677,075**	$ 683,112
Adjusted EBITDAX	**$ 291,353**	$ 296,126
Consolidated Leverage Ratio	**2.32**	2.31

The Consolidated Interest Coverage Ratio is calculated as follows:

	March 31, 2025	December 31, 2024
Adjusted EBITDAX	**$ 291,353**	$ 296,126
Interest expense, excluding non-cash expenses	**58,904**	58,068
Consolidated Interest Coverage Ratio	**4.95**	5.10

The Consolidated Current Ratio is calculated as follows:

	March 31, 2025	December 31, 2024
a) Consolidated Current Assets		
Consolidated current assets, as reported	**$ 151,939**	$ 173,828
Plus: Materials inventory in warehouse (capped)	**20,000**	20,000
Consolidated current assets for covenant purposes	**$ 171,939**	$ 193,828
b) Consolidated Current Liabilities		
Consolidated current liabilities, as reported	**$ 167,627**	$ 145,283
Less: Current portion of lease obligations	**4,841**	4,479
Less: Current portion of long term debt	**25,000**	12,500
Less: Deferred income (capped)	**15,000**	15,000
Consolidated current liabilities for covenant purposes	**$ 122,786**	$ 113,304
Consolidated Current Ratio	**1.40**	**1.71**

The Consolidated Assets Coverage Ratio is calculated as follows:

	March 31, 2025	December 31, 2024
PDP PV10 value	**$ 263,106**	$ 263,106
Term Loan principal balance	**50,000**	50,000
Consolidated Assets Coverage Ratio	**5.26**	5.26

As at May 7, 2025, the Corporation had 34.1 million common shares, 0.7 million stock options, 1.8 million RSU’s, DSU’s and PSU’s, and 1.9 million share purchase warrants outstanding.

Contractual Obligations

The following table provides a summary of the Corporation's cash requirements to meet its financial liabilities and contractual obligations existing as at March 31, 2025:

	Less than 1 year	1-3 years	Thereafter	Total
Long-term debt – principal	$ 25,000	$ 225,000	$ 495,000	$ 745,000
Lease obligations – undiscounted	5,203	6,753	—	11,956
Trade and other payables	93,550	—	—	93,550
Taxes payable	21,360	—	—	21,360
Other long term obligations	952	3,199	2,384	6,535
Long-term incentive compensation liability	1,397	1,095	—	2,492
Exploration and production contracts	13,324	9,911	1,759	24,994
Compression station operating contracts	1,016	1,777	—	2,793
	$ 161,802	**$ 247,735**	**$ 499,143**	**$ 908,680**

Letters of Credit

As at March 31, 2025, the Corporation had letters of credit outstanding totaling $61.0 million (December 31, 2024 - $66.9 million) to guarantee work commitments on exploration blocks in Colombia and to guarantee other contractual commitments.

Exploration and Production Contracts

The Corporation has entered into a number of exploration contracts in Colombia which require the Corporation to fulfill work program commitments and issue financial guarantees related thereto. In aggregate, the Corporation has outstanding exploration commitments at March 31, 2025 of $25.0 million and has issued $13.8 million of the total $61.0 million in financial guarantees related thereto.

Sustainability

Canacol is currently a leading sustainable natural gas producer in the Americas. In 2024, the Corporation achieved Scope 1 and 2 GHG emission intensities that were more than 45% lower on average than its gas focused peers and more than 75% lower on average than its oil focused peers in North and South America. Canacol's ambition is to continue to lead the oil and gas industry in Colombia in terms of supplying the increasing energy demands of Colombians while reducing carbon emissions, exploring avenues for renewable energy generation, fostering national energy self-sufficiency, and catalyzing the growth and development of Colombia's economy and its people. Canacol enthusiastically supports the global objectives to meet the Paris Agreement targets and remains committed to supporting Colombia's objective of achieving a 51% reduction in emissions by 2030. In line with this commitment, Canacol has set its decarbonization goals, whereby we aim to reduce Scope 1 and 2 emissions by 35% by 2035 and achieve carbon neutrality by 2050. The Corporation's objective on ESG is to improve the quality of life of millions of people through the exploration, production and supply of conventional natural gas in Colombia. Alongside this, Canacol is focused on generating value for its stakeholders in a sustainable, collaborative, co-responsible, respectful and transparent way. With the Corporation's transition to natural gas, it has an environmentally friendly value proposition that contributes to the reduction of CO2 emissions in Colombia and provides for a more efficient use of resources.

The Corporation continues to support its communities in essential social projects such as access to water and utilities, local economic projects, construction and improvement of public and community infrastructure, technical and university scholarships, amongst others.

The Corporation has strong corporate governance standards and procedures, which are aligned with best global practices, and uses control mechanisms that protect shareholder's interests, respect and promote human rights, guarantee ethical behavior, integrity and transparency, ensure regulatory compliance and minimize risk.

These accomplishments reflect Canacol's dedication to sustainability and its role as a leader in the industry. This is recognized by third-party ESG and sustainability rating agencies, where we maintained an 'A' qualification in MSCI for the second consecutive year and were positioned in the top 10 of the 2024 Sustainability Yearbook according to the Corporate Sustainability Assessment ("CSA") by S&P Global Sustainable 1.

The Corporation is committed to continuing to develop and maintain a robust ESG strategy and, as such, has implemented a plan with the following three pillars:

1. A cleaner energy future – deliver natural gas under the highest environmental and operational efficiency standards.
2. Empowering our people – make a positive impact on people and demonstrate Canacol's commitment to enhancing the well-being, prosperity, and health and safety of our employees, contractors, and the communities we serve.
3. A transparent and ethical business – adopt best practices, incorporate governance, encourage respect for human rights and ensure ethics and integrity in everything Canacol does.

Outlook

In 2025, the Corporation is focused on:

i. Maintaining and growing Canacol's EBITDA generation and reserves via investment in drilling, workovers, and new facilities projects to take advantage of higher commodity prices;

ii. Exploring higher impact gas exploration opportunities in the Lower Magdalena Valley ("LMV");

iii. Reducing debt;

iv. Laying the groundwork to be able to commence operations in Bolivia in 2026; and

v. Continuing the Corporation's commitment to its ESG strategy on a cost-effective basis.

The Corporation expects that commodity pricing will remain strong for the remainder of 2025, and for this reason, in 2025, the Corporation lowered its take-or-pay volumes to maximize exposure to the spot sales market. In line with maintaining and growing Canacol's reserves and production in its core assets in the LMV, the Corporation plans to optimize its production and increase reserves by drilling up to 11 exploration/appraisal wells and three development wells, installing new compression and processing facilities as required, and completing workovers of producing wells in its key gas fields. These development and exploration activities are planned to support Canacol's robust EBITDA generation and allow the Corporation to capitalize on strong gas market dynamics in 2025. Planned development wells include the Clarinete-11, Siku-2 and Lulo-3 wells, all of which have already been successfully drilled and brought on production. The exploration drilling plan includes 10 gas exploration/appraisal wells in the LMV and one gas and condensate exploration well in the Middle Magdalena Valley ("MMV"). Notable exploration wells in the LMV include continuing operations at Natilla-2.

The Corporation is currently preparing to sidetrack the Natilla-2 exploration well. Current operations include the installation of a whipstock within the 7-inch casing prior to milling a window and initiating the drilling of the sidetrack. The objective of the sidetrack is to redrill the gas bearing Porquero interval, and continue on to drill the deeper primary CDO sandstone target.

The Corporation completed the drilling of the Fresa-3 appraisal well in mid-April 2025. The well encountered 93 ft TVD of net gas pay within the main CDO sandstone reservoir, and is currently producing at a rate of 8.6 MMcfpd of natural gas.

Over the last several years, the Corporation has assembled a significant acreage position in the MMV and in 2025, the Corporation plans to drill the Valiente prospect targeting a large shallow structure located approximately five kilometers to the south and up dip of the Opon gas field discovered in 1965 by Cities Services and later developed by Amoco in 1997.

The Corporation is also continuing its efforts with respect to the Pola exploration project located in the MMV. Pola is a large prospect targeting gas within Cretaceous aged reservoirs at depths close to 17,000 feet. Given the relatively high cost of the well, the Corporation is currently evaluating its options with respect to how to proceed with the project.

In Bolivia, the Corporation is awaiting ratification and formalization by Congress of three exploration contracts (Arenales, Ovai, and Florida Este) and one field redevelopment contract (Tita) in order to establish the effective date of all four contracts. The Corporation is currently preparing to apply for the environmental permit for Tita, along with formulating development plans, in order to commence field reactivation activities in 2026.

SUMMARY OF QUARTERLY RESULTS

(in United States dollars (tabular amounts in thousands) except as otherwise noted)

	2025	2024				2023		
	Q1	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Financial								
Total revenues, net of royalties and transportation expense[1]	**72,735**	98,339	87,934	88,288	77,691	79,718	76,618	74,605
Adjusted funds from operations[1]	**39,316**	52,119	57,909	57,121	42,226	30,958	48,950	33,686
Per share – basic ($)[1]	**1.15**	1.53	1.70	1.67	1.24	0.91	1.44	0.99
Per share – diluted ($)[1]	**1.15**	1.53	1.70	1.67	1.24	0.91	1.44	0.99
Cash flows provided (used) by operating activities	**62,588**	42,428	21,692	49,202	54,719	22,571	66,212	(24,413)
Net income (loss) and comprehensive income (loss)	**31,801**	(25,434)	10,346	(21,298)	3,654	29,897	(524)	39,990
Per share – basic ($)	**0.93**	(0.75)	0.30	(0.62)	0.11	0.88	(0.02)	1.17
Per share – diluted ($)	**0.93**	(0.75)	0.30	(0.62)	0.11	0.88	(0.02)	1.17
Adjusted EBITDAX[1]	**56,268**	76,054	85,844	73,187	61,041	53,144	62,103	60,654
Weighted average shares outstanding – basic	**34,120**	34,115	34,111	34,111	34,111	34,111	34,111	34,111
Weighted average shares outstanding – diluted	**34,209**	34,115	34,111	34,111	34,111	34,111	34,111	34,111
Net cash capital expenditures[1]	**50,477**	28,634	23,928	33,853	35,878	72,246	43,830	51,985
Operations								
Production								
Natural gas and LNG (Mcfpd)	**133,773**	161,360	164,551	162,652	154,043	168,127	181,028	187,687
Colombia oil (bopd)	**1,227**	933	1,607	1,700	1,405	627	531	527
Total (boepd)	**24,696**	29,242	30,476	30,235	28,430	30,123	32,290	33,455
Realized contractual sales								
Natural gas and LNG (Mcfpd)	**128,693**	158,033	159,764	158,541	150,421	164,840	178,188	184,752
Colombia oil (bopd)	**1,195**	947	1,594	1,681	1,389	590	511	523
Total (boepd)	**23,773**	28,672	29,623	29,495	27,779	29,509	31,772	32,936
Operating netbacks[1]								
Natural gas and LNG ($/Mcf)	**5.48**	6.12	5.25	5.34	4.90	4.39	4.14	3.94
Colombia oil ($/bbl)	**13.76**	11.54	19.81	21.98	20.15	13.29	25.99	18.57
Corporate ($/boe)	**30.36**	34.18	29.42	29.95	27.51	24.82	23.62	22.36

(1) Non-IFRS measure – see “Non-IFRS Measures” section within this MD&A.

RISKS AND UNCERTAINTIES

There have been no significant changes in the three months ended March 31, 2025 to the risks and uncertainties as identified in the MD&A for the year ended December 31, 2024. A more comprehensive discussion of risks and uncertainties is contained in the Corporation's Annual Information Form for the year ended December 31, 2024 as filed on SEDAR+ and hereby incorporated by reference.

CRITICAL ACCOUNTING POLICIES AND ESTIMATES

The Corporation's management made judgements, assumptions and estimates in the preparation of the financial statements. Actual results may differ from those estimates, and those differences may be material. The basis of presentation and the Corporation's significant accounting policies can be found in the notes to the financial statements.

CHANGES IN ACCOUNTING POLICIES

The Corporation has not implemented new accounting policies during the three months ended March 31, 2025. Detailed discussions of new accounting policies and impact are provided in the financial statements.

REGULATORY POLICIES

Disclosure Controls and Procedures

Disclosure Controls and Procedures ("DC&P") are designed to provide reasonable assurance that all material information is gathered and reported on a timely basis to senior management so that appropriate decisions can be made regarding public disclosure and that information required to be disclosed by the issuer under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation. The Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO"), along with other members of management, have designed, or caused to be designed under the CEO and CFO's supervision, DC&P and established processes to ensure that they are provided with sufficient knowledge to support the representations made in the interim certificates required to be filed under National Instrument 52-109.

Internal Controls over Financial Reporting

The CEO and CFO, along with participation from other members of management, are responsible for establishing and maintaining adequate Internal Control over Financial Reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial statements prepared in accordance with IFRS Accounting Standards.

During the three months ended March 31, 2025, there has been no change in the Corporation's ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

Limitations of Controls and Procedures

The Corporation's management, including its CEO and CFO, believe that any DC&P or ICFR, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, they cannot provide absolute assurance that all control issues and instances of fraud, if any, within the Corporation have been prevented or detected. These inherent limitations include the realities that judgements in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Accordingly, because of the inherent limitations in a cost effective control system, misstatements due to error or fraud may occur and not be detected. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.