Management's Discussion and Analysis
For the three and nine months ended September 30, 2026 and 2025
Dated November 12, 2026

BUSINESS DESCRIPTION AND READER GUIDANCE

Condor Energies Inc. ("Condor" or the "Company") is an internationally focused energy transition company incorporated on October 20, 2006 that is uniquely positioned on the doorstep of European and Asian markets with three distinct first-mover energy security initiatives: increasing natural gas and condensate production from its eight gas fields in Uzbekistan; an ongoing project to construct and operate Central Asia's first LNG 'lower carbon fuel' diesel substitution facility in Kazakhstan; and a separate initiative to develop and produce critical minerals from brines in Kazakhstan. Condor has built a strong foundation for reserves, production and cashflow growth while also striving to minimize its environmental footprint.

Condor is a publicly traded company listed on the Toronto Stock Exchange under the symbol "CDR". Additional information relating to the Company, including its Annual Information Form for the year ended December 31, 2025, is available on SEDAR+ at: www.sedarplus.ca.

The Company's Management's Discussion and Analysis ("MD&A") which follows should be read in conjunction with the Company's unaudited interim condensed consolidated financial statements for the three and nine months ended September 30, 2026 and 2025 (the "Financial Statements"), and the audited consolidated financial statements and associated MD&A for the years ended December 31, 2025 and 2024. The Financial Statements have been prepared in accordance with International Accounting Standard 34, *Interim Financial Reporting*, under IFRS Accounting Standards as issued by the International Accounting Standards Board ("IFRS"). This MD&A is dated November 12, 2026, the date that Condor's Board of Directors approved the Financial Statements and this MD&A.

All financial amounts are in Canadian dollars, unless otherwise stated.

OVERALL PERFORMANCE

- Production in Uzbekistan for the third quarter of 2026 averaged 16,693 boe/d comprised of 16,240 boe/d (97.4 MMscf/d) of natural gas and 453 bopd of condensate which is a total production increase of 20% from the second quarter of 2026 and a total production increase of 67% from the third quarter of 2025.
- Uzbekistan natural gas and condensate sales for the third quarter of 2026 increased to $33.6 million or a 24% increase from the second quarter of 2026.
- During the period from November 1, 2026 through November 11, 2026, the Company achieved a new average production record of 18,631 boe/d primarily due to the completion and tie in of recently drilled wells.

- Five new wells were drilled and completed during the third quarter of 2026 and the Company has now drilled and completed eleven wells to date in 2026 and plans to drill and complete up to an additional four wells by year end.
- Initial test results from the Andakli-22 horizontal well ("A-22") drilled in October 2026 indicate that commercially recoverable gas may be produced outside of conventionally targeted four-way structural closures.
- The Company also drilled its first deeper Jurassic clastic reservoirs well at North Syuzma ("NS-14") in October and November 2026 and encountered 54 meters of net gas pay based on wireline logs. The drilling rig is being moved off location and completion and testing activities will commence shortly.
- In August 2026 an EPC contract was awarded to install the first phase of a field booster compressor station (the "Compressor Station") in Uzbekistan which is expected to increase production rates by lowering the gathering system pressure.
- In October 2026 acceptance testing was completed for the Company's first LNG facility (the "First LNG Facility") for the Saryozek plant site (the "Saryozek Site") and shipping to Kazakhstan is underway with an expected arrival in December 2026.
- In October 2026, the Company completed an offering of 12% unsecured convertible debentures for gross proceeds of $72.0 million. The debentures are convertible into common shares of the Company at a conversion price of $6.00 per common share and mature on October 15, 2029.

Production in Uzbekistan

The Company operates under a production enhancement services contract with JSC Uzbekneftegaz ("UNG") in Uzbekistan to increase the production, recovery, and overall system efficiency from an integrated cluster of eight conventional natural gas-condensate fields (the "PEC Project"). The cumulative license area is 282 km^2 or the equivalent of 109 sections, with 78 producing wells which produce gas mainly from Jurassic carbonate reservoirs.

Production in Uzbekistan for the third quarter of 2026 averaged 16,693 boe/d comprised of 16,240 boe/d (97.4 MMscf/d) of natural gas and 453 bopd of condensate which is a 20% production increase compared to the second quarter of 2026 and a 67% increase compared to the third quarter of 2025.

The Company continues to target previously undeveloped reservoirs within its 282 km^2 (~109 sections equivalent) license area with the objective of generating sustained production growth. Although most of the 2026 drilling activity has focused on the Kumli license, one of the two drilling rigs was recently relocated to the northern Andakli license and drilled A-22 outside of existing mapped structural closure boundaries. A-22 has demonstrated that commercially recoverable gas can be produced outside of conventionally targeted four-way structural closures which could become part of the Company's next growth engine.

A-22 was drilled to a total measured depth of 3,455 meters with a lateral interval of 1,127 meters. After A-22 was acid stimulated, it was tested for an 8-hour period that yielded an average flowing rate of 6.0 MMscf/d (1,000 boepd) on a 1" choke at 444 psi average flowing tubing pressure. There was no condensate produced and the liquid rate was 667 barrels per day, which consisted primarily of drilling and completion fluids and spent acid. The well was immediately tied into the gas sales line and continues to produce while further cleaning up.

The A-22 test rate is a short-term test rate and may not be indicative of long-term performance or ultimate recovery. The Company believes the A-22 test result is very impactful as it may open significant areas of prospective drilling acreage at Andakli and help derisk the commerciality of a stratigraphic horizontal well development program. Numerous Andakli follow up wells are planned as part of the 2027 drilling campaign.

After drilling the A-22 stratigraphic play, the rig moved to the Company's North Syuzma field to drill the NS-14 vertical delineation well that targeted the deeper Jurassic clastic stacked reservoir sands. The Company previously perforated a portion of this sand package on two legacy wells in November 2025 which flowed at a combined gas rate of 13.3 MMscf/d as previously disclosed. NS-14 was drilled to 2,810 meters to evaluate the full extent of the stratigraphic column and encountered 54 meters of net gas pay based on wireline logs, with 40 meters of net gas pay in the clastics reservoirs and 14 meters in the carbonate reservoirs. Completion activities are planned to commence once the drilling rig is moved off the location and testing is expected to begin by the end of November 2026. Pending test results, up to three additional vertical and three additional horizontal follow up locations could be drilled at North Syuzma.

The Company is currently drilling the K-53 horizontal well ("K-53") on a separate structure within the Kumli license area. K-53 was originally designed as a multilateral well with two horizontal sections ("Legs") targeting separate carbonate reservoirs. While drilling the first leg, K-53 encountered a previously unmapped fault that resulted in the lateral penetrating both target reservoirs, effectively achieving the reservoir access originally contemplated through two horizontal legs. Given this outcome, the Company has elected to complete K-53 as a single-leg horizontal well which is expected to reduce additional drilling time and capital requirements.

Multilateral well designs remain an important option for future development, offering the potential for increased reservoir contact and production, lower drilling and tie-in costs relative to separate horizontal wells, and a reduced surface footprint. The Company intends to deploy this technology where reservoir and drilling conditions support its use.

Nine wells have been drilled in the Kumli NW structure so far in 2026, with one additional well planned in December 2026. Of the nine wells, only the Kumli-50 horizontal well ("K-50") has yet to be tied into the gas sales pipeline. During well cleanup operations, K-50 flowed at rates estimated up to 10 MMscf/d but has not yet flowed through well testing equipment due to produced drilling fluids, completion fluids and formation water that hinder its continuous flow. The well produces when the wellbore is lifted with nitrogen but the well cannot independently lift these fluids and has been shut in to monitor pressures while alternate methods to lift the fluids are evaluated for planned implementation in the fourth quarter of 2026 in conjunction with other well workover activities.

In October 2026, the Company conducted a pre-stimulation cleanup flow test on the Kumli-51 horizontal well ("K-51"), which is another well in the Kumli NW structure. Prior to stimulation, K-51 flowed at 11.6 MMscf/d (1,933 boe/d) during a 1.5-hour test through a 1-inch choke at a stabilized tubing pressure of 703 psi. The well produced drilling and completion fluids at 356 bopd with no condensate observed. K-51 was subsequently placed on production and is expected to undergo an acid stimulation in December 2026. The K-51 test rate is a short-term test rate and may not be indicative of long-term performance or ultimate recovery.

Installation of the Compressor Station remains a top priority for the Company, and an EPC contract was awarded in August 2026. Booster compression is expected to increase gas production by lowering the gathering system pressure, mitigating liquid loading effects in wellbores, and helping to manage the impact of fluctuating and increasing downstream pipeline pressures. Simulation work conducted by an independent third-party engineering company indicates compression could yield up to 30 MMscf/d of incremental gas production and extend end-of-field life. The Compressor Station is scheduled to be commissioned in the second quarter of 2027.

LNG in Kazakhstan

The Company's LNG initiative in Kazakhstan fully supports the government of Kazakhstan's strategic focus on creating energy security solutions that provide viable diesel fuel alternatives to ensure the country's transport sector functions despite worldwide fuel and energy disruptions. The Company's First LNG Facility for the Saryozek Site completed final pressure testing of the fully assembled unit and is expected to arrive in Kazakhstan in December 2026. Although the delivery schedule has slipped due to the delayed arrival and installation of the control system components, LNG production is expected to commence in the second quarter of 2027. The Company expects to produce, distribute, and sell LNG to offset industrial diesel usage in Kazakhstan and potential end-user applications include rail locomotives, long-haul truck fleets, marine vessels, mining equipment, municipal bus fleets, and high-horsepower heavy equipment and machinery, all of which are being utilized in other countries.

The First LNG Facility is designed with an initial production capacity of 48,000 gallons (80 MT) of LNG per day, and due to its modular design, production at the Saryozek Site is expected to be subsequently expanded by two additional 48,000 gallon per day facilities to fully utilize the gas allocation awarded for this site. The Saryozek Site is one of the three natural gas allocations awarded to the Company in Kazakhstan. The Company has secured 20 hectares of land at the Saryozek Site until July 2059 under an agreement which requires the Company to construct an LNG facility at the site prior to August 2030.

The Company is reviewing third-party financing alternatives to complete the First LNG Facility, and the Company may enter one or more partnerships (or other joint venture structures) at its sites in Kazakhstan where it has already secured feed gas allocations (including the First LNG Facility).

As of September 30, 2026, the Company has incurred CAD $10.5 million of costs for the First LNG Facility, and the estimated additional remaining costs for construction and commissioning are USD $21.0 million (CAD $29.8 million) including various ancillary equipment, feed gas hookup and piping, power generation, electrical infrastructure, distribution equipment and storage tanks, LNG loading facilities and rolling stock.

Condor has received three natural gas allocations at three different locations within Kazakhstan, and the Company plans to construct modular LNG facilities at all three locations. Based on the natural gas allocations of 21,798 m3/hour, 29,110 m3/hour and 20,500 m3/hour, respectively, the total potential LNG fuel produced is estimated to have an energy-equivalent volume of 1.5 million litres of diesel daily and could reduce CO_2 emissions by 390,000 MT per year, which is estimated to be equivalent to removing 85,000 cars from the road annually. See "Forward-Looking Statements" in this MD&A for further discussion on the risks and uncertainties related to the natural gas allocations and the Company's LNG initiatives.

$72.0 Million Financing of Convertible Debentures

In October 2026, the Company completed an offering of convertible debentures for aggregate gross proceeds of $72.03 million which are convertible into 12,005,481 common shares (the "2026 Debentures") and comprised a brokered public offering for gross proceeds of $28.75 million including the full exercise of the over-allotment option by the agents (the "Public Offering") and a concurrent non-brokered private placement for gross proceeds of $43.28 million (the "Private Placement") on the same terms and conditions except the 2026 Debentures issued under the Private Placement are subject to a statutory four-month hold period expiring on February 16, 2027.

The 2026 Debentures are unsecured, have no associated financial covenants, bear interest at 12% per annum payable quarterly in cash and in arrears, and the principal amount is convertible at any time at the option of the holder on or before the maturity date of October 15, 2029, at a conversion price of $6.00 per common share. The 2026 Debentures issued under the Public Offering are traded on the Toronto Stock Exchange under the symbol CDR.DB and those issued under the Private Placement are expected to commence trading following the four-month hold period on or about February 16, 2027.

The estimated issuance costs associated with the 2026 Debentures of $3.3 million are comprised of agent commissions, intermediary fees, legal and advisory fees, and regulatory costs. The net proceeds from the 2026 Debentures offering of $68.7 million is intended to be used to fund the Compressor Station in Uzbekistan, the First LNG Facility in Kazakhstan, working capital and general corporate purposes.

Critical Minerals Licenses in Kazakhstan

The Company holds a 100% working interest in two contiguous critical minerals mining licenses which provide subsurface exploration rights for solid minerals, including lithium and copper, for respective six-year terms. The 37,300-hectare Sayakbay license was awarded in July 2023 and the nearby 6,800-hectare Kolkuduk license was awarded in February 2025. There has been a significant increase in the number of mining licenses awarded in the areas adjacent to the Company's license areas and active copper exploration activities are underway by major mining companies, including Rio Tinto.

The Company has advanced an integrated geophysical program at Sayakbay. Historical gravity data was digitized, reprocessed, and incorporated into a three-dimensional density model, refining the interpretation of the Sayakbay Dome, adjacent structural depressions, and a major shear zone along the Moyunkum uplift. Unmanned Aerial Vehicle ("UAV") magnetic surveys further defined the geometry of the Sayakbay Dome, faults intersecting the structure, and other structural features that may be relevant to mineralizing fluid migration and copper deposition.

The Company is currently processing and interpreting a ground transient electromagnetic ("TEM") survey over the central portion of Sayakbay. The survey is designed to map prospective geoelectric horizons and structural features to depths of approximately 700 meters and to improve the identification and ranking of potential mineralized targets. Preliminary results have demonstrated good correlation with historical well resistivity data and have identified several geoelectric layers and lateral resistivity variations that may reflect changes in lithology, fluid saturation, or structure.

At Kolkuduk, the Company completed a UAV-borne magnetic survey during 2026. Interpretation of magnetic data, together with historical gravity, seismic, and geological information, further defined the anticlinal structure, faults, and prospective Taskuduk and Zhezkazgan formations. These formations are recognized hosts for sandstone-hosted copper mineralization within the Chu-Sarysu Basin.

The Company continues to evaluate the lithium-brine potential of both licenses. A prior well drilled within the Kolkuduk license territory for hydrocarbon exploration encountered and tested brine deposits with lithium concentrations of up to 130 milligrams per liter as reported by the Ministry of Geology of the Republic of Kazakhstan. A 1,000-meter column of tested and untested brine reservoirs has been identified from historical wireline log and core data. At Sayakbay, a prior legacy well drilled for hydrocarbon exploration encountered and tested brine deposits with lithium concentrations of 67 milligrams per liter in Carboniferous-aged intervals as reported by the Ministry of Geology of the Republic of Kazakhstan. A 670-meter column of tested and untested brine reservoirs has been identified from historical wireline log and core data. Other critical minerals identified at the Kolkuduk and Sayakbay licenses include rubidium, strontium and cesium. Given the heavily faulted systems the Company has mapped in this geothermally active region, it appears that mineralized brines have migrated into the basin's reservoirs, as is evident by the lithium concentrations on Condor's blocks, as previously reported by the Ministry of Geology of the Republic of Kazakhstan.

The Company is not treating these historical estimates as current mineral resources or mineral reserves as additional drilling and testing is necessary, and a qualified person has not done sufficient work to classify the historical estimates as current mineral resources or mineral reserves. It is uncertain if further drilling will result in either area being delineated as a mineral resource or reserve. The historical lithium concentration estimates should not be relied upon as indicative of the actual lithium concentration or the likelihood that the Company will be able to achieve similar production results.

The 2027 Sayakbay capital program is expected to be determined following completion and integration of the TEM results with the gravity, magnetic, and historical geological data. Depending on the results, the Company may densify the TEM survey grid over prospective areas and/or begin preparations for a core drilling program to test the highest-priority targets. If the Sayakbay TEM program demonstrates that the method is effective and produces promising results, the Company may undertake a similar TEM survey at Kolkuduk during 2027.

The initial development plan for Sayakbay includes conducting targeted geophysical surveys, coring programs and drilling and testing two wells to verify deliverability rates, confirming the lateral extension and concentrations of lithium in the tested and untested intervals, conducting preliminary engineering for the production facilities, and preparing a mineral resource or mineral reserves report compliant with National Instrument 43-101 *Standards of Disclosure for Mineral Projects*. Drilling at Sayakbay is not expected to commence before 2028 and the estimated costs for the initial development plan are USD $6.7 million (CAD $9.5 million). The initial development plan for the Kolkuduk license has not been determined.

RESULTS OF OPERATIONS

Non–Controlling Interest in the PEC Project

The Company recognizes 100% of the production volumes, sales volumes, sales revenues, royalties and expenses related to the PEC Project in Uzbekistan and then allocates 49% of the comprehensive income (loss) attributable to the non-controlling interest holder. This is consistent with the accounting and disclosure in the Financial Statements. Accordingly, the production volumes, sales volumes, sales revenues, royalties, expenses and netbacks disclosed in this MD&A related to the PEC Project are 100% of the amounts attributable to the PEC Project, of which 51% are attributable to the Company.

Production in Uzbekistan

Total Production	Three months ended September 30, 2026	Three months ended September 30, 2025	Change
Natural gas (Mcf)	8,964,316	5,397,457	3,566,859
Natural gas (boe)	1,494,053	899,576	594,477
Condensate (barrels)	41,706	18,401	23,305
Total (boe)	1,535,759	917,977	617,782
Daily Production			
Natural gas (Mcf/d)	97,438	58,668	66%
Natural gas (boe/d)	16,240	9,778	66%
Condensate (bopd)	453	200	126%
Total (boe/d)	16,693	9,978	67%

Total Production	Nine months ended September 30, 2026	Nine months ended September 30, 2025	Change
Natural gas (Mcf)	22,510,050	16,702,386	5,807,664
Natural gas (boe)	3,751,675	2,783,731	967,944
Condensate (barrels)	109,376	73,987	35,389
Total (boe)	3,861,051	2,857,718	1,003,333
Daily Production			
Natural gas (Mcf/d)	82,454	61,181	35%
Natural gas (boe/d)	13,742	10,197	35%
Condensate (bopd)	401	271	48%
Total (boe/d)	14,143	10,468	35%

Total production from the PEC Project in Uzbekistan for the three months ended September 30, 2026, increased 67% to an average of 16,693 boe/d comprised of 16,240 boe/d (97,438 Mcf/d) of natural gas and 453 bopd of condensate from 9,978 boe/d for the same period in 2025. Total production for the nine months ended September 30, 2026 increased 35% to an average of 14,143 boe/d comprised of 13,742 boe/d (82,454 Mcf/d) of natural gas and 401 bopd of condensate from 10,468 boe/d for the same period in 2025.

Since assuming operations in March 2024, the Company has flattened the natural production decline rates, which previously exceeded twenty percent annually through improved facility and infrastructure management, well workovers, and drilling new wells.

Operating Netbacks in Uzbekistan

Operating Netback – Natural Gas [1,2]	Natural Gas			
	Three months ended September 30		Nine months ended September 30	
	2026	2025	2026	2025
Sales ($000's)	29,961	17,623	74,191	55,480
Royalties ($000's)	(4,119)	(2,427)	(10,218)	(7,641)
Production costs ($000's)	(10,688)	(8,324)	(29,424)	(25,305)
Transportation and selling ($000's)	(1,047)	(634)	(2,545)	(1,948)
Operating netback ($000's)[1,2]	14,107	6,238	32,004	20,586
Sales volume (Mcf)	8,400,470	5,019,603	20,988,647	15,548,613
Sales ($/Mcf)	3.56	3.51	3.53	3.57
Royalties ($/Mcf)	(0.49)	(0.48)	(0.49)	(0.49)
Production costs ($/Mcf)	(1.27)	(1.66)	(1.40)	(1.63)
Transportation and selling ($/Mcf)	(0.12)	(0.13)	(0.12)	(0.13)
Operating netback ($/Mcf)[1,2]	1.68	1.24	1.52	1.32

Operating Netback – Condensate [1,2]	Condensate			
	Three months ended September 30		Nine months ended September 30	
	2026	2025	2026	2025
Sales ($000's)	3,590	1,116	9,058	4,806
Royalties ($000's)	(520)	(161)	(1,311)	(693)
Production costs ($000's)	(209)	(124)	(606)	(510)
Transportation and selling ($000's)	(16)	(7)	(40)	(28)
Operating netback ($000's)[1,2]	2,845	824	7,101	3,575
Sales volume (bbl)	40,849	18,063	106,123	73,421
Sales ($/bbl)	87.88	61.78	85.35	65.46
Royalties ($/bbl)	(12.73)	(8.91)	(12.35)	(9.44)
Production costs ($/bbl)	(5.12)	(6.86)	(5.71)	(6.95)
Transportation and selling ($/bbl)	(0.39)	(0.39)	(0.38)	(0.38)
Operating netback ($/bbl)[1,2]	69.64	45.62	66.91	48.69

Operating netback reconciliation **Uzbekistan segmented information** **For the three months ended September 30, 2026** [1,2,3]	**Natural Gas**	**Condensate**	**Total**
Sales ($000's)	29,961	3,590	33,551
Royalties ($000's)	(4,119)	(520)	(4,639)
Production costs ($000's)	(10,688)	(209)	(10,897)
Transportation and selling ($000's)	(1,047)	(16)	(1,063)
Operating netback ($000's)[1]	14,107	2,845	16,952
For the three months ended September 30, 2025 [1,2,3]			
Sales ($000's)	17,623	1,116	18,739
Royalties ($000's)	(2,427)	(161)	(2,588)
Production costs ($000's)	(8,324)	(124)	(8,448)
Transportation and selling ($000's)	(634)	(7)	(641)
Operating netback ($000's)[1]	6,238	824	7,062

Operating netback reconciliation **Uzbekistan segmented information** **For the nine months ended September 30, 2026** [1,2,3]	**Natural Gas**	**Condensate**	**Total**
Sales ($000's)	74,191	9,058	83,249
Royalties ($000's)	(10,218)	(1,311)	(11,529)
Production costs ($000's)	(29,424)	(606)	(30,030)
Transportation and selling ($000's)	(2,545)	(40)	(2,585)
Operating netback ($000's)[1]	32,004	7,101	39,105
For the nine months ended September 30, 2025 [1,2,3]			
Sales ($000's)	55,480	4,806	60,286
Royalties ($000's)	(7,641)	(693)	(8,334)
Production costs ($000's)	(25,305)	(510)	(25,815)
Transportation and selling ($000's)	(1,948)	(28)	(1,976)
Operating netback ($000's)[1]	20,586	3,575	24,161

1 Operating netback is a non-GAAP measure and is a term with no standardized meaning as prescribed by GAAP and may not be comparable with similar measures presented by other issuers. See "Non-GAAP Financial Measures" in this MD&A. The calculation of operating netback is aligned with the definition found in the Canadian Oil and Gas Evaluation Handbook.

2 Amounts and per unit measures are only presented for the Uzbekistan segment.

3 Reconciliation to the respective financial statement amount for each netback component for the Uzbekistan segment.

Sales in Uzbekistan

For the three months ended September 30 ($000's)	2026	2025	Change
Natural gas	29,961	17,623	12,338
Condensate	3,590	1,116	2,474
Total	33,551	18,739	14,812

For the nine months ended September 30 ($000's)			
Natural gas	74,191	55,480	18,711
Condensate	9,058	4,806	4,252
Total	83,249	60,286	22,963

Natural gas sales increased to $29.96 million on 8,400,470 Mcf or $3.56 per Mcf for the three months ended September 30, 2026 compared to $17.62 million on 5,019,603 Mcf or $3.51 per Mcf for the same period in 2025, and increased to $74.19 million on 20,988,647 Mcf or $3.53 per Mcf for the nine months ended September 30, 2026 compared to $55.48 million on 15,548,613 Mcf or $3.57 per Mcf for the same period in 2025, due primarily to increased gas sales volumes from increased production.

Condensate sales increased to $3.59 million on 40,849 barrels or $87.88 per barrel for the three months ended September 30, 2026 compared to $1.12 million on 18,063 barrels or $61.78 per barrel for the same period in 2025, and increased to $9.06 million on 106,123 barrels or $85.35 per barrel for the nine months ended September 30, 2026 compared to $4.81 million on 73,421 barrels or $65.46 per barrel for the same period in 2025 due primarily to higher condensate sales volumes from increased production and higher Brent crude oil prices (a global benchmark for pricing crude oil).

Marketing in Uzbekistan

Natural gas is collected by gathering lines into two in-field facilities for initial processing to remove water and condensate and then transported by pipeline to a nearby third-party facility for further processing and onward transport by pipeline to the designated delivery point. Natural gas sales are domestic sales at local market prices. A portion of the associated condensate is separated from the natural gas at the two in-field facilities, and the remainder is separated and processed at the third-party facility. Condensate is sold to the buyer directly at each of the three facilities and the buyer is responsible for all onward transportation costs. Condensate sales prices are based upon Brent crude less a discount for processing, transportation and marketing.

Royalties in Uzbekistan

Royalties and production entitlements increased to $4.64 million for the three months ended September 30, 2026 compared to $2.59 million for the same period in 2025 and increased to $11.53 million for the nine months ended September 30, 2026 compared to $8.33 million for the same period in 2025 primarily due to higher sales revenue in 2026. In accordance with the terms of the PEC Project, certain of the Company's payment obligations for royalty expenses are deferred. These royalty expenses and associated liabilities are initially recognized at fair value by discounting the expected future payments at the Company's estimated incremental borrowing rate of 16%. The liabilities are subsequently accreted over the deferral period to the principal amount on the due date with a corresponding non-cash accretion charge recognized in finance expense.

Excluding the respective discounting impact on certain royalty expenses for each period, the Company is subject to a 10% production entitlement payable to UNG (the "UNG Entitlement") based on realized sales prices and a 10% government subsoil tax that is reimbursed to UNG on the natural gas and condensate produced under the PEC Project based on realized sales prices less certain adjustments for processing and transportation costs. The effective total royalty and production entitlement rate including the discounting impact for the three and nine months ended September 30, 2026 is 13.8% for both periods (September 30, 2025 – 13.8% for both periods).

Production costs in Uzbekistan

Production costs to produce natural gas were $10.69 million or $1.27 per Mcf for the three months ended September 30, 2026 compared to $8.32 million or $1.66 per Mcf for the same period in 2025, and were $29.42 million or $1.40 per Mcf for the nine months ended September 30, 2026 compared to $25.31 million or $1.63 per Mcf for the same period in 2025. Production costs to produce condensate were $0.21 million or $5.12 per boe for the three months ended September 30, 2026 compared to $0.12 million or $6.86 per boe for the same period in 2025, and were $0.61 million or $5.71 per boe for the nine months ended September 30, 2026 compared to $0.51 million or $6.95 per boe for the same period in 2025. Per unit production costs decreased due primarily to fixed costs remaining relatively consistent while sales volumes increased for the three and nine months ended September 30, 2026 compared to the same periods in 2025. Total production costs increased due primarily to higher sales volumes for both periods in 2026 compared to the same periods in 2025. Production costs in Uzbekistan are mainly comprised of facility, processing, compression, personnel, vehicle, equipment rental, safety and maintenance costs.

Transportation and selling in Uzbekistan

Transportation and selling costs for natural gas were $1.05 million or $0.12 per Mcf for the three months ended September 30, 2026 compared to $0.63 million or $0.13 per Mcf for the same period in 2025, and were $2.55 million or $0.12 per Mcf for the nine months ended September 30, 2026 compared to $1.95 million or $0.13 per Mcf for the same period in 2025. Transportation and selling costs for condensate were $0.02 million or $0.39 per boe for the three months ended September 30, 2026 compared to $0.01 million or $0.39 per boe for the same period in 2025 and were $0.04 million or $0.38 per boe for the nine months ended September 30, 2026 compared to $0.03 million or $0.38 per boe for the same period in 2025. These costs are comprised of pipeline costs to deliver natural gas and associated condensate to the processing facilities and to deliver natural gas onwards to the designated sales delivery point and are fixed on a per unit basis.

Türkiye production, sales, royalties, production, transportation and selling costs

The Company produces and sells small amounts of natural gas in Türkiye. For the three months ended September 30, 2026 compared to the same period in 2025; natural gas production increased to 1,011 Mcf or an average of 11 Mcf/d in 2026 from 815 Mcf or an average of 9 Mcf/d in 2025; natural gas sales were consistent at $0.01 million on 1,011 Mcf in 2026 compared to 670 Mcf in 2025; realized gas prices increased to $14.13 per Mcf in 2026 from $13.64 per Mcf in 2025; royalties were less than $0.01 million in both periods; production costs were consistent at $0.16 million in both periods; and transportation and selling costs were less than $0.01 million in both periods.

For the nine months ended September 30, 2026 compared to the same period in 2025; natural gas production increased to 3,796 Mcf or an average of 14 Mcf/d in 2026 from 2,342 Mcf or an average of 9 Mcf/d in 2025; natural gas sales increased to $0.05 million on 3,565 Mcf in 2026 from $0.02 million on 1,851 Mcf in 2025; realized gas prices increased to $13.54 per Mcf in 2026 from $13.06 per Mcf in 2025; royalties were less than $0.01 million in both periods; production costs increased to $1.07 million in 2026 from $0.45 million in 2025 due to a number of workovers performed; and transportation and selling costs were less than $0.01 million in both periods.

Sale of Turkish Properties

The Company entered into a share purchase agreement (the "SPA") in January 2026 for a third-party buyer to acquire the Company's 100% interest in the Poyraz Ridge and Destan operating licenses and gas fields in Türkiye (the "Turkish Properties") for consideration of 18,000 Euros and a gross overriding royalty at rates ranging from zero to 15% depending on average daily production volumes from the Turkish Properties, calculated as sales revenues less government royalties and less transportation costs, for a period of ten years subject to an aggregate cap of USD $10.0 million. The transaction is subject to Turkish government approvals (the "Government Approvals") and completion shall occur within ten business days of receiving the Government Approvals and either party may terminate the SPA if the Government Approvals are not received by January 21, 2027. As of September 30, 2026, the Company determined that the Turkish Properties did not meet the criteria to be classified as held for sale as it was not highly probable given uncertainties regarding the timing of the Government Approvals that this transaction would close prior to January 21, 2027. See "Forward-Looking Statements" in this MD&A for further discussion on the risks and uncertainties related to the SPA.

General and administrative

General and administrative expenses, comprised mainly of personnel, professional services, office, and travel costs, increased to $3.22 million for the three months ended September 30, 2026 from $2.16 million for the same period in 2025, and increased to $9.59 million for the nine months ended September 30, 2026 from $6.65 million for the same period in 2025, primarily due to higher personnel, consultants, professional services, travel and office costs related to the Uzbekistan project and higher costs in 2026 related to other new business initiatives.

Depletion and depreciation

Depletion and depreciation increased to $6.82 million for the three months ended September 30, 2026 from $2.96 million for the same period in 2025, and increased to $15.88 million for the nine months ended September 30, 2026 from $9.41 million for the same period in 2025. The increase is primarily due to increased depletion in Uzbekistan resulting from higher natural gas sales volumes in 2026 and a higher per unit depletion rate based on estimated proved plus probable reserves as determined by the Company's independent reserve engineers as of December 31, 2025. Changes in decommissioning costs in Türkiye and Kazakhstan relating to oil and gas properties with no net book value are recognized immediately as depletion and depreciation expense and totalled $0.06 million and $0.35 million for the three and nine months ended September 30, 2026, respectively (September 30, 2025 – $0.10 million and $0.72 million, respectively).

Stock based compensation

Stock based compensation expenses were consistent at $0.30 million for the three months ended September 30, 2026 compared to $0.25 million for the same period in 2025, and increased to $1.57 million for the nine months ended September 30, 2026 from $1.28 million for the same period in 2025. The expense is recognized on a graded basis and fluctuates based on the fair value of stock options determined at the date of grant, the timing of the grants, vesting periods and estimated forfeiture rates.

Finance income

Finance income was consistent at $0.10 million and $0.30 million for the three and nine months ended September 30, 2026, respectively, compared to $0.14 million and $0.35 million, respectively, for the comparable periods in 2025. Finance income is primarily related to interest income earned on cash and cash equivalents and other long-term assets.

Finance expense

Finance expense increased to $2.06 million and $5.65 million for the three and nine months ended September 30, 2026, respectively, from $1.03 million and $2.97 million, respectively, for the comparable periods in 2025. Effective interest expense on the loan facilities and Debentures increased to $1.09 million and $3.52 million for the three and nine months ended September 30, 2026, respectively, from $0.61 million and $1.78 million, respectively, for the comparable periods in 2025, primarily due to the 2025 Debentures, as defined herein, which were issued in December 2025.

The non-cash accretion expense of provisions was $0.21 million and $0.58 million for the three and nine months ended September 30, 2026, respectively (September 30, 2025 – $0.15 million and $0.46 million, respectively).The non-cash interest expense of lease liabilities was $0.32 million and $0.40 million for the three and nine months ended September 30, 2026, respectively (September 30, 2025 – $0.02 million and $0.07 million, respectively) primarily due to a new lease liability for the use of a drilling rig.

The non-cash accretion expense on certain PEC Project payment obligations for royalty expenses for the three and nine months ended September 30, 2026 was $0.40 million and $1.02 million, respectively (September 30, 2025 – $0.20 million and $0.48 million, respectively). The total undiscounted cash outflows required to settle these obligations are $20.93 million and are due between March 2029 and September 2031.

The Company had no risk management contracts that would be affected by interest rates in place during the nine months ended September 30, 2026 and the year ended December 31, 2025.

Foreign currency exchange gains and losses

The foreign exchange gain for the three and nine months ended September 30, 2026 was $0.42 million and $0.56 million, respectively, compared to $0.27 million and $0.90 million, respectively, for the comparable periods in 2025, due primarily to a USD denominated intercompany loan in Kazakhstan and USD cash and cash equivalents held by the Company, partially offset by the USD denominated Loan Facility, Bridge Loan and 2024 Debentures, all as defined herein. The Company is exposed to significant foreign currency risk as the Company's natural gas and condensate sales and a substantial portion of foreign activities are transacted in or referenced to foreign currencies, a portion of the Company's cash and cash equivalents are held in USD and the Company's Loan Facility, Bridge Loan and the 2024 Debentures are denominated in USD.

Natural gas and condensate sales in Uzbekistan are domestic sales at local market prices, and natural gas sales in Türkiye are denominated in TRL.

The Company had no forward exchange rate contracts in place during the nine months ended September 30, 2026 and the year ended December 31, 2025.

Gain (loss) on embedded derivative:

As the 2024 Debentures were denominated in a currency other than the Company's functional currency, the conversion feature in the 2024 Debentures was accounted for as an embedded derivative liability and its fair value was estimated at each reporting period date and the conversion date of June 8, 2026 with changes in fair value recognized in earnings as a gain or loss. The Company recognized a loss on embedded derivative of $Nil and $0.77 million for the three and nine months ended September 30, 2026, respectively, compared to a gain of $0.48 million and $0.80 million, respectively, for the comparable periods in 2025.

Other expense

On April 15, 2025, the Company acquired the rights to a natural gas allocation in Kazakhstan for USD $0.48 million (CAD $0.66 million) to provide LNG feed gas for the First LNG Facility. The natural gas allocation did not meet the recognition criteria for an asset and was expensed during the nine months ended September 30, 2025.

Income taxes

Income tax expense for the three and nine months ended September 30, 2026 is comprised of current income tax expense of $1.37 million and $3.75 million, respectively (September 30, 2025 – $0.60 million and $2.35 million, respectively) and deferred income tax recovery of $0.24 million and $1.15 million, respectively (September 30, 2025 – $0.06 million and $0.54 million, respectively) primarily related to Uzbekistan, where the tax rate is 15% of taxable income. The Company has not recognized the deferred tax benefits associated with the operating activities of other business segments.

Net income

Net income for the three months ended September 30, 2026 increased to $3.80 million compared to $0.86 million for the same period in 2025, primarily due to higher sales volumes and revenues, partially offset by higher expenses for production, general and administrative, depletion and depreciation, finance expense and income taxes, and no gain on embedded derivative.

Net income for the nine months ended September 30, 2026 was consistent at $2.90 million compared to $3.01 million for the same period in 2025, primarily due to higher expenses for production, transportation and selling, general and administrative, depletion and depreciation, finance expense, loss on embedded derivative and income taxes, partially offset by higher sales volumes and revenues and lower other expense.

Non-controlling interest ("NCI")

A third-party NCI shareholder holds 49% of the shares of Condor Natural Gas B.V. ("CNG"), the sole shareholder of the Company's subsidiary which is conducting the production enhancement services under the PEC Project in Uzbekistan. This NCI is allocated 49% of the comprehensive income of CNG commencing March 1, 2024.

A third-party NCI shareholder holds 10% of the shares of Condor LNG Ltd. ("CLNG"), the sole shareholder of three Kazakhstan subsidiaries which are developing LNG facilities in Kazakhstan. This NCI is allocated 10% of the comprehensive loss of CLNG commencing April 24, 2024.

NON-GAAP FINANCIAL MEASURES

The Company refers to "operating netback" in this MD&A, a term with no standardized meaning as prescribed by GAAP and which may not be comparable with similar measures presented by other issuers. This additional information should not be considered in isolation or as a substitute for measures prepared in accordance with GAAP. Operating netback is calculated as sales less royalties, production costs and transportation and selling costs on a dollar basis and divided by the sales volume for the period on a per Mcf basis for natural gas and per boe basis for condensate. The reconciliation of this non-GAAP measure is presented in the "Operating Netbacks in Uzbekistan" section of this MD&A. This non-GAAP measure is commonly used in the oil and gas industry to assist in measuring operating performance against prior periods on a comparable basis and has been presented to provide an additional measure to analyze the Company's sales on a per unit basis and the Company's ability to generate funds.

LIQUIDITY AND CAPITAL RESOURCES

The Company commenced production enhancement services under the PEC Project in Uzbekistan in March 2024 and is responsible for all capital expenditures and operating costs associated with performing its services, including a minimum development work program as described in "Commitments and Contingent Liabilities" in this MD&A. In June 2024, the Company initiated a multi-well workover campaign which involved the installation of various artificial lift equipment, perforating previously non-depleted and bypassed pay zones, performing downhole stimulation treatments, and isolating identified water intervals. In September 2025, the Company commenced a multi-well drilling program and plans to drill up to four additional wells in 2026. The design and construction of the Compressor Station is ongoing and is expected to be commissioned in the second quarter of 2027.

The Company has an LNG initiative in Kazakhstan and is constructing its First LNG Facility to produce, distribute and sell LNG to displace diesel fuel usage in Central Asia which is expected to be commissioned in the second quarter of 2027.

The Sayakbay exploration license in Kazakhstan contains contractual work commitments of $0.2 million per annum during the first three years and $0.3 million per annum during the final three years of the six-year term. The Kolkuduk exploration license in Kazakhstan contains contractual work commitments of approximately $0.05 million per annum during the first three years and $0.1 million per annum during the final three years of the six-year term. The contractual work commitments may be amended from time to time in accordance with planned exploration activities proposed by the Company and approved by the Government of Kazakhstan and additional contractual work commitment amounts could be significant.

These initiatives will require the Company to use a combination of cash on hand, increase cashflows from operating activities, secure funding from debt or equity financing, dispose of assets or make other arrangements. There is no assurance that the Company will be successful with these initiatives and the outcome of these matters is uncertain.

The Company previously had the following borrowing arrangements which have been settled: i) a term loan facility ("Loan Facility") due July 14, 2026 which was unsecured, non-revolving, bore interest at 9% per annum payable in cash quarterly and the full amount of principal and interest on the Loan Facility was repaid on the maturity date; ii) convertible debentures (the "2024 Debentures") due March 21, 2027 which were unsecured, bore interest at 9% per annum payable in cash semi-annually and were converted into 2,950,336 common shares on June 8, 2026, accounted for by derecognizing both the carrying amount of the liability and embedded derivative components and recognizing them as share capital; and iii) a USD $5.0 million bridge loan ("Bridge Loan"), which was unsecured, bore interest at 12% per annum, had no repayment of principal or accrued interest due until the extended maturity date of November 16, 2026 and the full amount of principal and interest on the Bridge Loan was repaid in October and November 2026.

The Company currently has the following borrowing arrangements: i) convertible debentures (the "2025 Debentures") of $13.1 million which are convertible into 6,552,500 common shares, are unsecured, bear interest at 12% per annum payable in cash semi-annually, and with the principal due on the maturity date of December 24, 2028, unless converted into common shares at a conversion price of $2.00 per common share; and ii) the 2026 Debentures of $72.0 million which are convertible into 12,005,481 common shares, are unsecured, bear interest at 12% per annum payable quarterly in cash in arrears, and with the principal due on the maturity date of October 15, 2029, unless converted into common shares at a conversion price of $6.00 per common share. The 2024 and 2025 Debentures are collectively referred to as the "Debentures".

As at September 30, 2026, the Company had a deficit of $11.24 million (December 31, 2025 – $8.10 million). For the three and nine months ended September 30, 2026, the Company reported a net income of $3.80 million and $2.90 million, respectively (September 30, 2025 – $0.86 million and $3.01 million, respectively) and cash flows from operating activities of $12.96 million and $19.71 million, respectively (September 30, 2025 – $15.15 million and $18.79 million, respectively). The Company's working capital deficiency increased from $4.13 million as at December 31, 2025 to $20.72 million as at September 30, 2026 due primarily to the drilling program and Compressor Station in Uzbekistan and the construction of the First LNG Facility in Kazakhstan as described in "Commitments and Contingent Liabilities" in this MD&A. To support these development activities, the Company completed an offering of the 2026 Debentures for gross proceeds of $72.0 million on October 15, 2026 and a brokered public offering of 11,500,000 common shares for gross proceeds of $29.9 million on April 21, 2026, as described in this MD&A. Current liabilities were also reduced by all 2024 Debentures with a total carrying amount of $8.19 million which were converted into 2,950,336 common shares of the Company on June 8, 2026, partially offset by the current portion of a new lease liability for the use of a drilling rig in the amount of $6.0 million.

COMMITMENTS AND CONTINGENT LIABILITIES

Under the terms of the PEC Project, the Company is required to complete a five-year minimum development work plan (the "MDWP") which began in 2024 and establishes how the Company intends to enhance and optimize production from the eight natural gas-condensate fields. The MDWP includes the following work program: perform seventy-five well workovers, install artificial lifts in sixty wells, acquire 225 km2 of 3-D seismic, install water separation equipment, drill twenty-five new wells, install three field compression units, and perform upgrades for two in-field processing facilities. At the inception of the PEC Project, the estimated capital expenditures associated with the work program are USD $138.4 million (CAD $196.4 million), and the Company is entitled to determine the schedule and timing of completing the work program within the five-year period. The

MDWP also includes estimated operating expenses of USD $170.5 million (CAD $241.9 million). The Company is actively executing on the activities set out in the MDWP work program and incurring the associated capital and operating expenditures. The performance and implementation of the MDWP is monitored regularly and may be amended by agreement between the Company and UNG. If the Company is unable to substantially complete the MDWP by December 31, 2028, except due to certain specified conditions, this is a specific material breach which allows for UNG to terminate the PEC Project, unless the Company can successfully negotiate an extension or amendment to the MDWP with UNG. Actual expenditures required to complete the specified work program and to operate the fields may be significantly different from the above estimates.

The PEC Project in Uzbekistan contains contractual provisions that allow for termination of the project in the event of a material breach. With respect to the Company, a material breach may include, but is not limited to, failure to substantially complete the MDWP, failure to use its best efforts in accordance with good oilfield practices to increase production, failure to perform production enhancement operations in accordance with the terms of the PEC Project or causing a deterioration in the production conditions of natural gas and condensate that existed on March 1, 2024. If such a breach occurs and is not remedied by the Company within the specified correction period, UNG may terminate the PEC Project. The Company actively monitors compliance with all contractual terms and maintains internal controls to mitigate the risk of a material breach. However, there can be no assurance that all risks will be fully mitigated, and the termination of the PEC Project could have a significant adverse effect on the Company's results of operations, cash flows and financial condition.

The Company has capital commitments for the Compressor Station in Uzbekistan of USD $17.3 million (CAD $24.5 million), and additional progress payments are due in instalments based on various operational milestones during construction, commissioning, and the warranty period.

The Company has capital commitments for the First LNG Facility in Kazakhstan of USD $3.80 million (CAD $5.39 million), and the payments are due in a combination of time and milestone-based instalments until it is commissioned, which is expected to be in the second quarter of 2027.

The Company has a 100% interest in and operates two operating licenses and gas fields in Türkiye including Poyraz Ridge which is valid until June 2035 and Destan which is valid until June 2030. There are no work commitments related to the Poyraz Ridge or Destan operating licenses. See "Sale of Turkish Properties" in this MD&A.

The Sayakbay exploration license in Kazakhstan contains contractual work commitments of $0.2 million per annum during the first three years and $0.3 million per annum during the final three years of the six-year term. The Kolkuduk exploration license in Kazakhstan contains contractual work commitments of approximately $0.05 million per annum during the first three years and $0.1 million per annum during the final three years of the six-year term. The contractual work commitments may be amended from time to time in accordance with planned exploration activities proposed by the Company and approved by the Government of Kazakhstan and additional contractual work commitment amounts could be significant.

FINANCIAL RISK MANAGEMENT

Credit risk

Credit risk arises from the possibility that a counterparty to which the Company provides goods or services is unable or unwilling to fulfil their contractual obligations. The maximum exposure to credit risk at period end is as follows:

Carrying amounts as at ($000's)	September 30, 2026	December 31, 2025
Cash and cash equivalents	9,280	18,516
Trade and other receivables	28,074	16,046
Other long-term assets	274	268
	37,628	34,830

The Company limits its exposure to credit risk on cash and cash equivalents and bank deposits by depositing and investing in banks with investment grade credit ratings.

Credit risk on trade receivables is related mainly to natural gas marketers, and the risk of financial loss if a customer, partner or counterparty to a financial instrument fails to meet its contractual obligations. During the three and nine months ended September 30, 2026, natural gas was sold to one customer in each of Uzbekistan and Türkiye and condensate in Uzbekistan was sold to UNG and therefore all sales transactions are subject to concentration risk. As at September 30, 2026, these three customers represented 99% of outstanding trade and other receivables (December 31, 2025 – 99%). Of the $28.07 million trade and other receivables balance as of September 30, 2026, $11.79 million has been collected subsequent to September 30, 2026.

Credit risk is mitigated by management's policies and practices. Natural gas and condensate produced in Uzbekistan are supplied to the domestic market through sales agreements with national companies of Uzbekistan. For condensate sales receivables in Uzbekistan, if full payment is not received from UNG when due, the Company may withhold the outstanding amount receivable from the payment due to UNG for the UNG Entitlement. For natural gas sales in Türkiye, the Company holds a bank guarantee provided by the buyer of its natural gas amounting to two month's estimated gas sales as security on gas sales receivables.

Liquidity risk and capital management

Liquidity risk is the risk the Company will encounter difficulty in meeting financial obligations and commitments and repaying liabilities as they fall due. The Company's objective is to ensure, as far as possible, that it will have sufficient liquidity to meet its obligations when due. The Company requires liquidity mainly to satisfy financial obligations and operating requirements related to activities in Uzbekistan and Kazakhstan as described in "Commitments and Contingent Liabilities" in this MD&A, and Türkiye. The Company looks to manage liquidity by adjusting its capital structure by issuing new equity or debt, disposing of assets and making adjustments to its capital expenditure program to the extent the capital expenditures are not committed.

As at September 30, 2026, the Company does not have sufficient resources or committed financing to fund all the development activities described in "Commitments and Contingent Liabilities" in this MD&A and the Company's long term success and ability to manage these obligations is dependent upon its continued ability to generate positive cash flows from operating activities, securing funding from debt or equity financing, disposing of assets, making other arrangements, or deferring certain non-committed components of its development program. While the Company believes it has sufficient resources to manage these obligations for the next year, there is no assurance that the Company will be successful with these longer-term initiatives and the outcome of these matters is uncertain. The Company completed an offering of the 2026 Debentures for gross proceeds of $72.0 million on October 15, 2026 and a brokered public offering of 11,500,000 common shares for gross proceeds of $29.9 million on April 21, 2026, as described in this MD&A.

As at September 30, 2026, the Company had a deficit of $11.24 million (December 31, 2025 – $8.10 million). For the three and nine months ended September 30, 2026, the Company reported a net income of $3.80 million and $2.90 million, respectively (September 30, 2025 – $0.86 million and $3.01 million, respectively) and cash flows from operating activities of $12.96 million and $19.71 million, respectively (September 30, 2025 – $15.15 million and $18.79 million, respectively). The Company's working capital deficiency increased from $4.13 million as at December 31, 2025 to $20.72 million as at September 30, 2026 due primarily to the drilling program and Compressor Station in Uzbekistan and the construction of the First LNG Facility in Kazakhstan as described in "Commitments and Contingent Liabilities" in this MD&A. To support these development activities, the Company completed an offering of the 2026 Debentures for gross proceeds of $72.0 million on October 15, 2026 and a brokered public offering of 11,500,000 common shares for gross proceeds of $29.9 million on April 21, 2026, as described in this MD&A. Current liabilities were also reduced by all 2024 Debentures with a total carrying amount of $8.19 million which were converted into 2,950,336 common shares of the Company on June 8, 2026, partially offset by the current portion of a new lease liability for the use of a drilling rig in the amount of $6.0 million.

To manage capital expenditures and operating cashflows, annual budgets are prepared, monitored regularly and updated as required. The Company also utilizes authorizations for expenditures to manage capital spending.

The cash flows presented in the tables below are the contractual undiscounted cash flows and accordingly certain amounts differ from the amounts included in the consolidated statements of financial position. The Company's undiscounted contractual obligations are as follows:

($000's)	Less than 1 year	Greater than 1 year	Total
As at September 30, 2026			
Accounts payable and accrued liabilities	46,972	-	46,972
Lease liabilities	7,113	1,879	8,992
Bridge loan	8,054	-	8,054
Financing agreement	-	426	426
Convertible debentures	424	13,105	13,529
Other long-term liabilities	709	21,248	21,957

($000's)	Less than 1 year	Greater than 1 year	Total
As at December 31, 2025			
Accounts payable and accrued liabilities	21,279	-	21,279
Lease liabilities	322	276	598
Loan facility	5,749	-	5,749
Bridge loan	6,040	-	6,040
Convertible debentures	199	20,188	20,387
Other long-term liabilities	685	13,698	14,383

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 and their impact on the future performance of the business. Market risk is comprised of three types of market price changes: foreign currency exchange rates, interest rates and commodity prices. Derivative instruments may be used to reduce exposure to these risks.

Foreign currency exchange risk

The Company is exposed to significant foreign currency risk as the Company's natural gas and condensate sales and a substantial portion of foreign activities are transacted in or referenced to foreign currencies, a significant portion of the Company's cash and cash equivalents are held in USD and the Company's Loan Facility, Bridge Loan and the 2024 Debentures are denominated in USD. Natural gas and condensate sales in Uzbekistan are domestic sales at local market prices and natural gas sales in Türkiye are denominated in TRL. In general, an increase in the value of the CAD as compared to the USD or the TRL will reduce the prices received by the Company for its natural gas and condensate sales. The Company had no forward exchange rate contracts in place during the nine months ended September 30, 2026 and the year ended December 31, 2025.

During the nine months ended September 30, 2026, the CAD depreciated from 1.37 per 1.00 USD to 1.42, the KZT appreciated from 502.6 per 1.00 USD to 439.4, and the TRL depreciated from 42.9 per 1.00 USD to 48.9, which led to a foreign exchange gain of $0.56 million (September 30, 2025 – $0.90 million) related primarily to a USD denominated intercompany loan in Kazakhstan and USD cash and cash equivalents held by the Company, partially offset by the USD denominated Loan Facility, Bridge Loan and 2024 Debentures.

During the nine months ended September 30, 2026, the CAD depreciated from 1.37 per 1.00 USD to 1.42, the KZT appreciated from 367.2 per 1.00 CAD to 309.6, and the TRL depreciated from 31.3 per 1.00 CAD to 34.4, resulting in a $2.87 million translation gain adjustment through equity (September 30, 2025 – $0.71 million translation loss).

Interest rate risk

Interest rate risk is the risk that the value of the financial instrument or future cash flows associated with the financial instrument will fluctuate as a result of changes in market interest rates. The Company's Loan Facility and the 2024 Debentures bore fixed-rate interest at 9.0% per annum, and the Bridge Loan, 2025 Debentures and 2026 Debentures bear fixed-rate interest at 12.0% per annum. The value of these instruments is exposed to interest rate risk from changes in market interest rates. The Company had no risk management contracts that would be affected by interest rates in place during the nine months ended September 30, 2026 and the year ended December 31, 2025.

Commodity price risk

Commodity price risk is the risk that the fair value of future cash flows will fluctuate as a result of changes in commodity prices. The Company is exposed to changes in commodity prices inherent in the oil and natural gas industry. Commodity prices for oil and natural gas are impacted by economic events and factors which are beyond the Company's control. Fluctuations in petroleum and natural gas prices may have a significant effect on the Company's results of operations and cash flows from operating activities, and may also affect the value of the oil and gas properties, the level of spending for exploration and development and the Company's ability to raise capital. The Company had no derivative commodity price contracts in place during the nine months ended September 30, 2026 and the year ended December 31, 2025.

Natural gas sales in Uzbekistan are domestic sales at local market prices. Condensate sales prices in Uzbekistan are based on Brent crude less a discount for processing, transportation and marketing.

Natural gas sales in Türkiye are domestic sales via pipeline at prices published monthly by the state-owned pipeline transportation company BOTAS. The benchmark for Condor's gas sales in Türkiye is BOTAS Level 2 wholesale tariffs less a marketing differential.

HEALTH RISK MANAGEMENT

Condor has offices, activities and operations in various areas in Canada, Uzbekistan, Türkiye and Kazakhstan. Company personnel are stationed and work and travel to and from these locations as required. Such personnel are exposed from time to time to concentrated groups of people at various locations both within and outside the Company's direct control, for varying lengths of time. Any personnel or visitors that become infected with a serious illness that has the potential to spread rapidly throughout the organization could place the personnel and the operations of the Company at risk.

Although the Company takes precautions and follows industrial hygiene and occupational health guidelines, there can be no assurance that an infectious illnesses will not negatively impact Condor's personnel or its operations and may in the future result in fluctuating demand for oil and gas, volatile oil and gas prices and the implementation of various travel restrictions which constrain or prohibit international travel and limit or forbid movement within the individual countries of operation.

Condor's future operations could be materially impacted by these factors, as well as related emergency measures including, but not limited to: travel restrictions including shelter in place orders, curfews and lockdowns which may impact the timing and ability of Company personnel, suppliers and contractors to travel internationally or domestically and to access or deliver services, goods and equipment to the fields of operation; the risk of shutting-in or reducing production due to travel restrictions, government orders, crew illnesses and the availability of goods, works and essential services for the fields of operations; the potential for gas pipeline or sales market interruptions; the risk of changes to foreign currency controls, availability of foreign currencies, availability of hard currency, and currency controls or banking restrictions which restrict or prevent the repatriation of funds from or to foreign jurisdictions in which the Company operates; the timing and ability to meet financial and other reporting deadlines; potential decreased interest in and ability to conclude farm-in transactions, potential decreased ability to raise additional capital to fund current operations and new business projects; and the inherent increased risk of information technology failures and cyber-attacks.

OUTSTANDING SHARE DATA

Common shares

As at September 30, 2026, there were 86,591,974 common shares of the Company outstanding and as of the date of this MD&A, there were 86,794,474 common shares of the Company outstanding.

Stock options

As at September 30, 2026, and the date of this MD&A, the Company has 6,216,296 stock options outstanding with a weighted average exercise price of $1.31 per common share.

Other convertible securities

As of September 30, 2026, and as of the date of this MD&A, respectively, the Company has the following common share purchase warrants and convertible debentures outstanding:

			Number of common shares to be issued upon exercise	
Instrument	Exercise Price	Expiry Date	September 30, 2026	November 12, 2026
Warrants	$2.20	December 9, 2026	9,952	9,952
Warrants	$2.60	April 21, 2028	242,773	242,773
Warrants	$2.00	December 24, 2028	128,056	128,056
2025 Debentures	$2.00	December 24, 2028	6,552,500	6,350,000
2026 Debentures	$6.00	October 15, 2029	-	12,005,481

Dividends

The Company has not paid or declared any dividends since the date of incorporation, nor are any contemplated in the foreseeable future.

OFF-BALANCE SHEET ARRANGEMENTS

The Company did not have any off-balance sheet arrangements as at September 30, 2026.

RELATED PARTY TRANSACTIONS

The Bridge Loan was provided by EurAsia Resource Value SE, an existing significant shareholder of the Company.

QUARTERLY INFORMATION

The following table sets forth selected financial information of the Company for the eight most recently completed quarters to September 30, 2026:

For the quarter ended (000's except per share amounts)	Q3 2026	Q2 2026	Q1 2026	Q4 2025	Q3 2025	Q2 2025	Q1 2025	Q4 2024
Sales	33,566	27,152	22,580	20,380	18,748	19,292	22,270	20,982
Net income (loss) [1]	3,802	762	(1,669)	(1,782)	863	527	1,624	(1,318)
Net income (loss) attributable to common shareholders [2]	1,137	(1,010)	(3,269)	(2,498)	(480)	(1,149)	(85)	(3,303)
Net income (loss) per share [3]	0.01	(0.01)	(0.05)	(0.04)	(0.01)	(0.02)	(0.00)	(0.06)

1 The net income (loss) in all periods has been impacted by, among other things, production and sales volumes of natural gas and condensate, commodity prices, production costs, general and administrative costs, depletion and depreciation, finance expenses from the loan facilities and Debentures, gain (loss) on embedded derivative, changes in other expenses and foreign exchange gains and losses in the respective periods.

2 Net income (loss) attributable to common shareholders is presented after the allocation of net income (loss) attributable to non-controlling interests. See "Non-controlling interest ("NCI")" in this MD&A which describes the two NCIs.

3 Per share amounts are presented on a basic and diluted basis and are attributable to common shareholders. Potential common shares are included in diluted earnings per share when their effect is dilutive and excluded when their effect is anti-dilutive. If potential common shares are anti-dilutive based on earnings from continuing operations attributable to common shareholders, they are considered anti-dilutive for all other per share calculations.

CRITICAL ACCOUNTING ESTIMATES AND JUDGEMENTS

The timely preparation of financial statements requires management to make use of judgments, estimates and assumptions when transactions affecting the current accounting period cannot be finalized until future periods. These estimates will affect assets, liabilities and the disclosure of assets and liabilities at the date of the financial statements, as well as revenues and expenses during the reporting periods. Such estimates are based on informed judgments made by management. Actual results could differ from those estimates as future confirming events occur. Significant assumptions and estimates about the future and other sources of estimation uncertainty that management has made at the financial position reporting date that could result in a material adjustment to the carrying amount of assets and liabilities, in the event that actual results differ from assumptions made, are outlined below.

- identification of Impairment Indicators – Property, plant and equipment: Significant judgment is required to assess when internal or external indicators of impairment or impairment reversal exist, and impairment testing is required. Management considers internal and external sources of information including future natural gas and condensate prices, expected production volumes, future operating, royalty and capital costs, anticipated recoverable quantities of proved plus probable oil and gas reserves and rates used to discount the related future cash flow estimates. A downward revision in the reserve estimates or future forecast prices or an upward revision to future capital costs could result in an asset impairment which would reduce future earnings and the associated net book value of assets.

Judgment is required to assess these factors when determining if the carrying amount of an asset or CGU is impaired, or in the case of a previously impaired asset or CGU, whether the previous amount impaired can be reversed;

- Depletion: estimates include the amount of reserve volumes and future development capital. A downward revision in the reserve estimates or an upward revision to future capital may result in increased depletion and a reduction in net book value of assets if such a revision results in an accounting impairment. Depletion is charged on a unit-of-production basis over the Proved plus Probable reserves for each cash generating unit and a revision in the productive capacity of the assets may result in increased depletion and a reduced net book value of assets;
- E&E expenditures: costs associated with acquiring oil and gas licenses and exploratory drilling are accumulated as E&E assets pending determination of technical feasibility and commercial viability. Establishment of technical feasibility and commercial viability is subject to judgment and involves management's review of project economics, resource quantities, expected production techniques, production costs and required capital expenditures to develop and extract the underlying resources. Management uses the establishment of commercial reserves within the exploration area as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets attributable to those reserves are tested for impairment and reclassified from E&E assets to a separate category within property, plant and equipment referred to as oil and gas properties;
- Identification of Impairment Indicators – E&E assets: the Company assesses its E&E assets to determine whether any indication of impairment exists at the end of each reporting period if facts and circumstances suggest the carrying amount exceeds the recoverable amount. Significant judgment is required in determining whether indicators of impairment exist, including factors and considerations such as the remaining period for which the Company has the right to explore, whether expenditures on further exploration and evaluation of properties are budgeted, whether commercially viable quantities of mineral resources have been discovered or whether data exists to suggest the carrying amount is unlikely to be recovered;
- Decommissioning provisions: estimates include the amount and expected timing of asset retirements, discount and inflation rates and future cashflows. As a result of the long-term nature of the Company's operations, these estimates may change over time which may result in a change in the decommissioning provision and corresponding asset value, and impact future earnings (loss) as a result of changes in accretion and depletion expense;
- Convertible debentures: The conversion feature associated with the USD denominated 2024 Debentures was identified as a derivative financial liability. Derivative financial liabilities are recorded upon recognition and subsequently at each period-end date at fair value, with changes in fair value being recognized in earnings. The fair value estimate involves assumptions regarding the probability a forced conversion will occur, the expected life of the 2024 Debentures, dividend yields, risk-free interest rates and volatility of the Company's common shares. The fair value is measured using the Black-Scholes option pricing model, and using an alternate pricing model could produce different results;

- Stock based compensation: estimates include determining appropriate share price volatility, expected lives, forfeiture rates and risk-free rates. The expense is measured using the Black-Scholes option pricing model, and using an alternate pricing model could produce different results;

- Going concern: estimates include the ability to fund operations by generating positive cashflows from operations, securing funding from additional debt or equity financing, disposing of assets or making other arrangements;

- Income taxes: tax interpretations, regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and interpretation. As such, income taxes are subject to measurement uncertainty. Deferred tax assets are assessed by management at the end of the reporting period to determine the likelihood that they will be realized from future taxable earnings. Changes in the estimate of future taxable income and the recovery of deductible temporary differences may result in the recognition of a deferred tax asset on the statement of financial position and an increase in earnings at the time when the tax recovery is recorded; and

- Non-current assets or a disposal group held for sale and discontinued operations: Management applies judgement in determining whether non-current assets or a disposal group (the "Assets") meet the criteria to be classified as held for sale, which includes whether the Assets are available for immediate sale in their present condition and the sale is highly probable. In assessing whether the sale is highly probable, management considers, among other factors, the approval of a formal plan to dispose of the Assets, previous experience in completing similar transactions, obtaining government or regulatory approvals and the expected timing of completion. A discontinued operation is a component of the entity that is classified as held for sale or has been disposed of and that represents a separate major line of business or geographical area of operations. Judgement is required to determine if the Assets classified as held for sale are considered to be a discontinued operation.

- As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy and ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgement and estimates relating to activity levels, future cashflows and the timing thereof and other factors which may or may not be within the control of the Company (see "Liquidity and Capital Resources").

ADOPTED ACCOUNTING PRONOUNCEMENTS

The Company adopted *Amendments to IFRS 9 "Financial Instruments" and IFRS 7 "Financial Instruments: Disclosures" – Classification and Measurement of Financial Instruments* from January 1, 2026. The amendments clarify the date of recognition and derecognition of some financial assets and liabilities, with an exception that permits an entity to derecognize a financial liability before settlement date when the financial liability is settled through an electronic payment system that meets specific criteria. The amendments apply retrospectively; however, the Company was not required to restate prior periods to reflect their application under transitional provisions. Application of the amendments did not have a material effect on the Company's interim condensed consolidated financial statements for the three and nine months ended September 30, 2026.

FUTURE ACCOUNTING PRONOUNCEMENTS

IFRS 18 "Presentation and Disclosure in Financial Statements": On April 9, 2024, the IASB issued IFRS 18, which will replace International Accounting Standard 1, "Presentation of Financial Statements". IFRS 18 will establish a revised structure for the Consolidated Statements of Income and Comprehensive Income and improve comparability across entities and reporting periods. IFRS 18 is effective for annual periods beginning on or after January 1, 2027. The standard is to be applied retrospectively, with certain transition provisions. The Company is assessing the impact of IFRS 18 on the consolidated financial statements, particularly with respect to the structure of consolidated statements of income (loss), consolidated statements of cash flows and the additional disclosures required for management-defined performance measures.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

The Company's President and Chief Executive Officer and Vice President, Finance and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures ("DC&P") and internal controls over financial reporting ("ICFR") as defined in *National Instrument 52-109 Certification of Disclosure in Issuer's Annual and Interim Filings* in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the financial statements for external purposes in accordance with IFRS Accounting Standards.

During the three months ended September 30, 2026, there have been no changes to the Company's ICFR that have materially or are reasonably likely to materially affect the ICFR. Because of their inherent limitations, DC&P and ICFR may not prevent or detect misstatements, errors or fraud. Control systems, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control systems are met.

BUSINESS RISKS

In the normal course of business, the Company is exposed to a variety of risks and uncertainties. In addition to the risks associated with liquidity and capital resources, commitments and contingent liabilities, critical accounting estimates, financial instruments, credit risk and market risk described in this MD&A, the Company is exposed to various operational, technical, financial and regulatory risks and uncertainties, many of which are beyond its control and may significantly affect future results. Operations may be unsuccessful or delayed as a result of competition for services, supplies and equipment, mechanical and technical difficulties, the ability to attract and retain employees and contractors on a cost-effective basis, commodity and marketing risk and seasonality. The Company is exposed to considerable risks and uncertainties including, but not limited to:

- the timing and ability to find natural gas, condensate and critical mineral reserves on an economical basis;
- uncertainties related to estimating the initial production rate of the type curve horizontal wells;
- uncertainties related to estimating the increased production rates for installing field compression;
- uncertainties related to estimating the Company's reserves;
- financial risks including access to debt or equity markets on acceptable terms;

- technical problems which could lead to unsuccessful wells, well blowouts and environmental damage;
- obtaining regulatory approvals on a timely basis or at all;
- third-party related operational risks including the ability to obtain access to wells, access to third party processing facilities, and access to pipelines, railways and other transportation infrastructure;
- obtaining qualified personnel, parts, equipment and service providers in a timely and cost-efficient manner;
- fluctuations in commodity prices, interest rates and foreign currency exchange rates;
- adverse factors including climate, geographical and weather conditions and natural disasters;
- risks associated with human resources management including labor disputes;
- timing of future debt and other obligations;
- potential for prior year tax reassessments not aligned with previously filed and assessed periods;
- regulatory legislation and policies, including the fulfillment of contractual minimum work programs, the compliance with which may require significant expenditures and non-compliance with which may result in fines, penalties, production restrictions, suspensions or revocations of contracts;
- changes to taxation policies, laws and interpretations thereof;
- political risks inherent with international activities and doing business in foreign jurisdictions;
- medical and health risks inherent with international activities and doing business in foreign countries including travel bans or travel restrictions;
- obtaining comprehensive and appropriate insurance coverage at reasonable rates;
- obtaining approval for extensions to development periods;
- obtaining approval for extensions to exploration periods, and, upon commercial discovery, negotiating and signing development contracts;
- negative public or community response to natural gas, condensate and critical minerals exploration, development and production and related environmental impacts could adversely affect Condor's business and the price of its securities; and
- information technology and system risks including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, data privacy and destruction or interruption of the Company's information technology.

Please see the Company's Annual Information Form, filed on SEDAR+ at www.sedarplus.ca for further discussion on these risks.

GEOPOLITICAL INSTABILITY

In 2022, Russia commenced a military operation in Ukraine, and in response to the invasion several countries imposed financial and other trade sanctions against Russia, including prohibitions or restrictions from doing business anywhere in the world with listed Russian individuals or companies. New or additional sanctions or new or additional military operations in relation to the invasion are unknown at this time. Similarly, the results, continuation or escalation of the Israeli-Palestinian conflict, the Middle East conflicts (including the attacks by the U.S. and Israel on Iran and Iranian retaliation) and the U.S. intervention in Venezuela are unknown at this time. To-date these events have not impacted the Company's ability to carry on business, there have been no significant delays or direct security issues affecting the Company's operations, offices or personnel, and the enacted sanctions have not affected the Company's operations. The outcome of these events is uncertain at this time and may impact the peace and stability of the region and the world and could affect the global economy including regions and markets in which the Company operates. Any subsequent commodity supply shortages or volatile commodity prices could have adverse impacts on the world economy and the Company's business. If these events continue, re-occur or escalate, they could have a material adverse effect on Condor's business, financial condition or results of operations.

BARRELS OF OIL EQUIVALENT ADVISORY

References herein to barrels of oil equivalent ("boe") are derived by converting gas to oil in the ratio of six thousand standard cubic feet ("Mcf") of gas to one barrel of oil based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6 Mcf to 1 barrel, utilizing a conversion ratio at 6 Mcf to 1 barrel may be misleading as an indication of value, particularly if used in isolation.

FORWARD-LOOKING STATEMENTS

Certain statements in this MD&A constitute forward-looking information under applicable securities legislation. Such statements are generally identifiable by the terminology used, such as "anticipate", "expect", "plan", "believe", "intend", "estimate", "may", "will", "could", "would", "should", "potential", "prospective", "pending", "ongoing", "future", "forecast", "target", "continue", "capable", "schedule", "remain" or other similar wording. Forward-looking information in this MD&A includes, but is not limited to, information concerning: the timing and ability of the Company to execute growth and sustainability strategies including the financing for these activities; the timing and ability to conduct the planned multi-well drilling program in 2026 and 2027; the timing and ability of the identified drilling locations to be drilled and become producing wells; the timing and ability to complete, test and produce the new wells; the timing and ability to target previously undeveloped reservoirs and the timing and ability to generate sustained production growth; the timing and ability to produce commercially recoverable gas outside of conventionally targeted four-way structural closures; the timing and ability of new and stratigraphic play types to become part of the Company's next growth engine; the timing and ability of A-22 test results to open significant areas of prospective drilling acreage at Andakli and derisk the commerciality of a stratigraphic horizontal well development program; the timing and ability to drill numerous Andakli follow up wells in 2027; the timing and ability to drill NS-14 and penetrate the deeper Jurassic clastic stacked reservoir sands; the timing and ability for NS-14 to reach the targeted depth of up to 3000 meters and the timing and ability to evaluate the full extent of the stratigraphic column; the timing and ability to drill follow up wells at North Syuzma; the timing and ability to

target separate carbonate reservoirs from a single surface location; the timing and ability to perform an acid stimulation on K-51; the timing and ability to utilize proven technology to realize higher expected production rates; the timing and ability to realize increased reservoir contact, reduced well drilling and tie-in costs and a smaller environmental footprint; the timing and ability to implement alternate methods to lift fluids from K-50 and tie K-50 into the gas sales pipeline; the timing and ability to design, construct and commission the Compressor Station; the timing and ability of the Compressor Station to increase production and reduce back pressure; the timing and ability to substantially complete the MDWP under the PEC Project; the timing and ability to maintain compliance with contractual provisions that allow for termination of the PEC Project; the timing and ability to receive and utilize the natural gas allocations as feed gas for the planned modular LNG production facilities; the Company's expectations in respect of the future uses of LNG; the timing and ability to acquire, transport and construct modular LNG production facilities; the timing and ability to obtain funding for the construction of modular LNG production facilities on favourable terms, or at all; the timing and ability to secure third-party financing for the First LNG Facility; the timing and ability to enter into one or more partnerships (or other joint venture structures) at the Company's sites in Kazakhstan where it has already secured feed gas allocations; the timing and ability to produce and deliver LNG to displace diesel fuel usage in Central Asia; the Company's expectations regarding reduction in CO2 emissions based on productivity of the LNG facilities; the timing and ability to transport the First LNG Facility to Kazakhstan; the timing and ability to commence LNG production; the estimated costs to complete the First LNG Facility construction and commissioning; the timing and ability to construct the First LNG Facility at the Saryozek Site prior to August 2030 as required under the related land agreement; the timing and ability to liquefy natural gas to produce LNG; the timing and ability to confirm LNG volume commitments with potential end-users; the timing and ability of the First LNG Facility to produce 48,000 gallons of LNG per day; the timing and ability of the Company to construct two additional modular LNG facilities capable of producing 48,000 gallons of LNG per day at the First LNG Facility site; the timing and ability to finalize LNG off-taker agreements; the planned use of proceeds from the 2026 Debentures offering including the Compressor Station, First LNG Facility, working capital and general corporate purposes; the potential for the Sayakbay and Kolkuduk license to contain commercial deposits; the timing and ability to integrate the aeromagnetic survey results with historical gravity data and regional geological information; the timing and ability of the Sayakbay sediment to be suitable for hosted copper mineralization; the timing and ability to advance an integrated geophysical program at Sayakbay and incorporated the data into a three-dimensional density model; the timing and ability to refine the interpretation of various license area features; the timing and ability of UAV magnetic surveys to further define the area geometries, faults, formations and other structural features; the timing and ability to complete, process and interpret the TEM survey; the timing and ability to map prospective geoelectric horizons and structural features and to improve the identification and ranking of potential mineralized targets; the timing and ability to correlate preliminary results with historical well resistivity data; the timing and ability to identify geoelectric layers and lateral resistivity variations; the timing and ability to determine and complete the 2027 Sayakbay capital program; the timing and ability to densify the TEM survey grid; the timing and ability to begin preparations and to conduct a core drilling program; the timing and ability to undertake a TEM survey at Kolkuduk during 2027; the timing and ability of the Company to fund, permit and complete planned activities at Sayakbay; the timing and estimated costs of the initial development plan for Sayakbay; the timing and ability of the Company to generate a report in compliance with National Instrument 43-101 Standards of Disclosure for Mineral Projects; the timing and ability to determine, fund, permit and execute an initial exploration or development plan for the Kolkuduk license; the timing and ability to obtain the required Government Approvals and complete the sale of the Turkish Properties; the potential consequences of failing to obtain Government Approval to complete the sale of the Turkish Properties, including

the right of either party to terminate the SPA; the accuracy of the projections and timing with respect to natural gas and condensate production; expected markets, prices and costs for future natural gas and condensate sales; the timing and ability of the Company to obtain various approvals and conduct its planned exploration and development activities; the timing and ability to access natural gas pipelines; the timing and ability to access domestic and export sales markets; the accuracy of the anticipated capital expenditures; forecasted capital and operating budgets and cashflows; anticipated working capital; sources and availability of financing for potential budgeting shortfalls; the timing and ability to obtain future funding on favourable terms, if at all; the potential for additional contractual work commitments to be significant; the ability to satisfy and fund the contractual work commitments; projections relating to the adequacy of the Company's provision for taxes; the expected reporting impacts of adopting amendments to IFRS accounting policies; and treatment under governmental regulatory regimes and tax laws.

This MD&A also includes forward-looking information regarding health risk management including, but not limited to: travel restrictions including shelter in place orders, curfews and lockdowns which may impact the timing and ability of Company personnel, suppliers and contractors to travel internationally, travel domestically and to access or deliver services, goods and equipment to the fields of operation; the risk of shutting in or reducing production due to travel restrictions, government orders, crew illness, and the availability of goods, works and essential services for the fields of operations; decreases in the demand for oil and gas; decreases in the prices of natural gas, condensate and crude oil; potential for gas pipeline or sales market interruptions; the risk of changes to foreign currency controls, availability of foreign currencies, availability of hard currency, and currency controls or banking restrictions which restrict or prevent the repatriation of funds from or to foreign jurisdiction in which the Company operates; the Company's financial condition, results of operations and cash flows; access to capital and borrowings to fund operations and new business projects on terms acceptable to the Company; the timing and ability to meet financial and other reporting deadlines; and the inherent increased risk of information technology failures and cyber-attacks.

By its very nature, such forward-looking information requires Condor to make assumptions that may not materialize or that may not be accurate including, but not limited to, the assumptions that: the Company will be able to secure necessary drilling rigs, support services, and off-taker agreements in a timely manner; the Company will be able to manage its working capital deficiency; the Company will be able to drill the planned wells and install and commission the Compressor Station; the Compressor Station will perform substantially in accordance with the simulation work conducted by an independent third-party engineering company; the results of the A-22 test and other recently drilled wells will be indicative of the results of future follow up wells; the Company will be able substantially complete the MDWP and comply with the terms of the PEC Project; the Company will be able to secure third-party financing for the First LNG Facility; the Company will be able to enter into one or more partnerships (or other joint venture structures) at its sites in Kazakhstan where it has already secured feed gas allocations; the engineering design and final investment decisions for additional LNG facilities will proceed as planned; the First LNG Facility will arrive in Kazakhstan and be commissioned in accordance with the Company's current schedule; the Company will complete construction of its LNG facilities and that the LNG feed gas for such facilities will be supplied; the Government of Kazakhstan will continue to support energy security solutions, including LNG development, that provide viable diesel fuel alternatives; the Company's additional drilling and testing will be successful in verifying deliverability rates and confirming mineral concentrations; commodity prices, foreign currency exchange rates and interest rates will be consistent with the Company's expectations; the Company will be able to fund its initiatives through a combination of cash on hand, increased cashflows, debt or equity financing, asset sales, or other arrangements;

the Company will be able to manage liquidity and capital expenditures through budgeting and authorizations for expenditures; the Company will be able to manage health, safety, and operational risks through existing precautions and guidelines; the Company will be able to adapt to changing trade policies, tariffs, and restrictions; and the Company will be able to manage the impact of geopolitical instability and sanctions. Forward-looking information is subject to both known and unknown risks and uncertainties and other factors, which may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such information. Such risks and uncertainties include, but are not limited to: regulatory changes including changes to environmental regulations; the timing of regulatory approvals; the risk that actual minimum work programs will exceed the initially estimated amounts; the results of exploration and development drilling and related activities; the risk that prior lithium testing results may not be indicative of future testing results or actual results; the risk of imprecision of reserves estimates and ultimate recovery of reserves; the risk that historical production and testing rates may not be indicative of future production rates, capabilities or ultimate recovery; the risk that the historical composition and quality of oil and gas does not accurately predict its future composition and quality; general economic, market and business conditions; risks relating to the uncertainty related to marketing and transportation; competitive action by other companies; fluctuations in oil and natural gas prices; the effects of weather and climate conditions; fluctuation in interest rates and foreign currency exchange rates; the ability of suppliers to meet commitments; actions by governmental authorities, including increases in taxes, tariffs, levies and fees; decisions or approvals of administrative tribunals and the possibility that government policies or laws may change or the possibility that government approvals may be delayed or withheld; risks associated with oil and gas operations, both domestic and international; and other factors, many of which are beyond the control of Condor.

These risk factors are discussed in greater detail in filings made by Condor with Canadian securities regulatory authorities including the Company's most recent Annual Information Form, which may be accessed through SEDAR+ at www.sedarplus.ca.

Readers are cautioned that the foregoing list of factors affecting forward-looking information is not exhaustive. The forward-looking information contained in this MD&A is made as of the date of this MD&A and, except as required by applicable law, Condor does not undertake any obligation to update publicly or to revise any of the included forward-looking information, whether as a result of new information, future events or otherwise. The forward-looking information contained in this MD&A is expressly qualified by this cautionary statement.

ABBREVIATIONS

The following is a summary of abbreviations used in this MD&A:

Mbbl	Thousands of barrels of oil
Mboe	Thousands of barrels of oil equivalent
Mcf	Thousands of standard cubic feet
Mcf/d	Thousands of standard cubic feet per day
MMcf/d	Millions of standard cubic feet per day
bbl	Barrels of oil
bopd	Barrels of oil per day
boe	Barrels of oil equivalent
boe/d	Barrels of oil equivalent per day
MT	Metric tonnes
IFRS	International Financial Reporting Standards
GAAP	Generally Accepted Accounting Principles
CAD	Canadian Dollars
KZT	Kazakhstan Tenge
TRL	Turkish Lira
USD	United States Dollars
LNG	Liquefied natural gas
Türkiye	Republic of Türkiye
Kazakhstan	Republic of Kazakhstan
Uzbekistan	Republic of Uzbekistan
3-D	Three dimensional
EPC	Engineering, Procurement and Construction
NW	North-West
NE	North-East
USGS	United States Geological Survey