2025
Annual Report

Bonterra Energy Corp.
December 31, 2025

ABOUT BONTERRA

Bonterra Energy Corp. is a conventional oil and gas corporation forging a grounded path forward for Canadian energy. Operations include a large, concentrated land position in Alberta's Pembina Cardium, one of Canada's largest oil plays. Bonterra's liquids-weighted Cardium production provides a foundation for implementing a return of capital strategy over time, which is focused on generating long-term, sustainable growth and value creation for shareholders.

Emerging Charlie Lake and Montney resource plays are expected to provide enhanced optionality and an expanded potential development runway for the future. Our shares are listed on the Toronto Stock Exchange under the symbol "BNE" and we invite stakeholders to follow us on LinkedIn and X for ongoing updates and developments.

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Patrick G. Oliver, *President & CEO*
Scott A. Johnston, *CFO & Corporate Secretary*
Brad A. Curtis, *Senior VP, Business Development*

REPORT TO SHAREHOLDERS

2025 Letter To Shareholders

Dear valued Shareholders,

I am pleased to report that Bonterra Energy delivered a breakthrough year in 2025, achieving or exceeding nearly every objective we set at the start of the year. Through disciplined execution and continued operational excellence, we enhanced capital efficiency and strengthened our balance sheet liquidity. Strategic acquisitions further expanded and strengthened our asset base, positioning the Company and our shareholders for sustained growth and long-term value creation.

A Breakthrough Year

In 2025, we continued to advance the strategic transformation initiated in prior years, pivoting from a pure-play Cardium producer to a more diversified portfolio focused on high-impact Charlie Lake and Montney resource plays. This transition has materially reshaped our business, with these emerging assets contributing to approximately one-third of corporate production in just two years, while significantly expanding our tier-1 drilling inventory and expanding our long-term development runway.

Our operational execution continued to be a defining feature of the year. We surpassed the high end of our revised production guidance, achieving a record annual production of 15,513 BOE per day, despite a challenging commodity price environment. This growth was driven by the successful execution of our Charlie Lake drilling program, reactivation of wells and ongoing optimization of our base Cardium assets.

Importantly, this production growth was achieved with $69.9 million of capital, within our revised guidance and substantially below historical levels. This performance demonstrates our improved capital efficiency and underscores the strength and resilience of our high-impact asset base.

Strategic Growth and Asset Expansion

A key highlight in 2025 was the continued expansion of our Charlie Lake core area. In December, we completed the acquisition of the Bonanza assets for $15.3 million, adding approximately 760 BOE per day of low-decline production, 41 net sections of land, and 21 top-tier drilling locations that complement our existing inventory. This acquisition further strengthened our position in one of our most capital-efficient plays while creating immediate development synergies through strategically located infrastructure and gathering systems.

Operationally, we were encouraged by the strong performance of our Charlie Lake wells, including two three-mile horizontal wells drilled in November that ranked in the top 20 wells drilled industry-wide for the month. Together, they achieved a combined peak IP30 rate of approximately 2,700 BOE per day. These results reinforce the quality of the resource and underscore our technical team’s ability to execute complex drilling programs efficiently and safely.

We also continued advancing the delineation of our 55+ sections of contiguous Montney land base, drilling our third Montney well and our first three-mile horizontal well in this play. The well was completed in January 2026, with production testing commencing in mid-February, representing an important step in unlocking the significant long-term potential of our contiguous Montney acreage.

Further supporting our asset expansion strategy, Bonterra grew its reserves across the TP and TPP reserve categories by 3%, underpinning a TPP Reserve Life Index of 19.4 years. At the same time, we reduced our TP and TPP F&D costs to $12.72 per BOE and $14.93 per BOE, driving recycle ratios of 2.1x and 1.8x, respectively.

Financial Strength and Capital Discipline

Over the course of 2025, we took additional steps to enhance our financial flexibility and simplify our capital structure. Through our high-yield debt refinancing, we strengthened liquidity and created a covenant-friendly framework that allowed for renewal and subsequent expansions of our credit facility from $110 million to $150 million. As a result, we exited the year with approximately $110 million of liquidity on our balance sheet, providing a solid foundation to support our growth plans.

Funds flow totaled $94.2 million, while adjusted free funds flow increased by 65% year-over-year to $17.2 million, despite lower crude oil prices, highlighting the impact of the improved capital efficiency realized from the Charlie Lake drilling program. Field netbacks averaged $22.05 per BOE and cash netbacks averaged $16.63 per BOE, demonstrating the resiliency of our asset base in a mid-cycle pricing environment.

We also maintained a disciplined approach to capital allocation and shareholder returns. During 2025, we repurchased 749,900 shares, or approximately 2% of our outstanding common shares under our Normal Course Issuer Bid, reflecting our confidence in the intrinsic value of the Company and our commitment to long-term value creation for shareholders.

Operational Momentum and Team Excellence

The successes Bonterra achieved in 2025 are a testament to the strength, expertise, and dedication of our people, unlocking a key competitive advantage. We saw exceptional performance from our technical and operational teams, while executing complex drilling and development programs safely and efficiently. Our team's disciplined approach enabled record quarterly production while deploying significantly less capital than in prior years, demonstrating operational excellence and a culture of continuous improvement to support sustainable, long-term growth.

Carrying Momentum into 2026

We entered 2026 with strong operational momentum and an active capital program already underway. In the first quarter, we drilled three Charlie Lake wells, including two two-mile wells at 13-20 and 12-20, and a three-mile well at 03-25. The DUCs drilled in December 2025 have since been completed, including the 12-30 three-mile well in the Charlie Lake, along with our 16-12 three-mile Montney well. These wells position the Company for continued production growth throughout 2026.

Our 2026 capital program is designed to grow production through disciplined allocation across our three core assets. New well activity and waterflood capital directed to the Cardium will further optimize our base cash flow stream, while drilling programs in the Charlie Lake and Montney are expected to increase production exposure and further prove out the value of these high-impact assets. M&A will continue to be an integral component of our growth strategy, targeting attractive opportunities within our three core areas.

We reaffirm our 2026 guidance of average production between 16,200 and 16,400 BOE per day and capital expenditures between $75 million and $80 million. We remain committed to a disciplined balance sheet strategy, prioritizing the use of free funds flow for debt repayment and opportunistic share buybacks, while maintaining flexibility to respond to a potential challenging commodity price environment.

Closing Remarks

Reflecting on 2025, I want to extend my sincere gratitude to our employees, Board of Directors, and partners. We could not have achieved this breakthrough year without your dedication, support, and commitment to excellence. I would also like to welcome Andy Mah to our Board of Directors and thank Michael Stewart for his many years of service and contributions to Bonterra.

Fundamental to our success is the continued trust and support of our shareholders. We thank you for your confidence and trust as we build Bonterra thoughtfully and responsibly for the long-term. Your support enables us to pursue growth, execute our strategy, and create lasting value, and we are proud to have you with us on this journey.

Sincerely,

Patrick Oliver
President & Chief Executive Officer

ANNUAL HIGHLIGHTS
FINANCIAL AND OPERATIONAL HIGHLIGHTS

As at and for the year ended ($000s except $ per share)		**December 31, 2025**	December 31, 2024	December 31, 2023
FINANCIAL				
Revenue - realized oil and gas sales		**247,874**	279,957	319,517
Funds flow[(1)]		**94,168**	118,668	147,305
Per share - basic		**2.57**	3.18	3.96
Per share - diluted		**2.55**	3.18	3.95
Cash flow from operations		**89,480**	114,952	140,183
Per share - basic		**2.44**	3.08	3.77
Per share - diluted		**2.43**	3.08	3.76
Net earnings (loss)[(2)]		**(17,125)**	10,203	44,943
Per share - basic		**(0.47)**	0.27	1.21
Per share - diluted		**(0.46)**	0.27	1.20
Capital expenditures		**69,932**	101,076	126,478
Oil and gas property acquisition[(3)(4)]		**16,029**	24,234	-
Total assets		**959,434**	975,043	967,870
Net debt[(5)]		**179,049**	167,210	145,440
Bank debt		**40,722**	46,211	14,822
Shareholders' equity		**522,032**	540,639	528,258
OPERATIONS				
Light oil	-bbl per day	**6,415**	6,639	7,209
	-average price ($ per bbl)	**81.24**	94.35	97.58
NGLs	-bbl per day	**1,511**	1,513	1,359
	-average price ($ per bbl)	**41.61**	46.97	48.80
Conventional natural gas	-MCF per day	**45,524**	40,164	33,814
	-average price ($ per MCF)	**2.09**	1.68	3.12
Total barrels of oil equivalent per day (BOE)[(6)]		**15,513**	14,846	14,204

(1) Funds flow, while not recognized under IFRS®, is used by management to assess the Company's ability to generate cash from operations. For these purposes, the Company defines funds flow as funds provided by operations including proceeds from sale of investments and investment income received excluding the effects of changes in non-cash working capital items and decommissioning expenditures settled.

(2) Net loss for the year ended December 31, 2025, primarily reflects a one-time debt extinguishment cost of $11.6 million.

(3) On March 1, 2024, the Company acquired the Charlie Lake Assets for cash consideration of $23.6 million and $0.3 million in non-core mineral rights, including closing adjustments. The Charlie Lake Assets has been accounted for as an asset acquisition, which resulted in an increase of $24.2 million in PP&E and the assumption of $0.3 million in decommissioning liabilities.

(4) On December 18, 2025, the Company acquired the Bonanza Assets adjacent to the Company's Charlie Lake area assets for cash considerations of $15.3 million in mineral rights, including closing adjustments. This acquisition has been accounted for as an asset acquisition, which resulted in a $16.0 million increase in PP&E and the assumption of $ 0.7 million in decommissioning liabilities.

(5) Net debt is not a recognized measure under IFRS. The Company defines net debt as current liabilities less current assets plus long-term bank debt, subordinated debentures, subordinated term debt and subordinated notes.

(6) BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

QUARTERLY HIGHLIGHTS

	2025			
As at and for the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1
Financial				
Revenue - oil and gas sales	**57,833**	55,166	64,185	70,690
Funds flow	**22,111**	21,330	23,092	27,635
Per share - basic	**0.61**	0.59	0.63	0.74
Per share - diluted	**0.60**	0.58	0.62	0.73
Cash flow from operations	**21,526**	8,344	29,996	29,614
Per share - basic	**0.60**	0.23	0.81	0.79
Per share - diluted	**0.59**	0.23	0.80	0.78
Net loss	**(4,648)**	(3,554)	(1,313)	(7,610)
Per share - basic and diluted	**(0.13)**	(0.10)	(0.04)	(0.20)
Capital expenditures	**16,348**	14,783	6,351	32,450
Oil and gas property acquisition	**16,029**	-	-	-
Total assets	**959,434**	935,536	949,202	978,798
Bank debt	**40,722**	26,011	29,614	24,209
Net debt	**179,049**	167,803	169,938	186,102
Shareholders' equity	**522,032**	526,565	530,935	533,830
Operations				
Light oil (barrels per day)	**6,274**	6,051	6,794	6,546
Average price ($ per bbl)	**71.90**	81.92	79.85	91.22
NGLs (barrels per day)	**1,507**	1,353	1,508	1,679
Average price ($ per bbl)	**37.61**	40.42	42.58	45.39
Conventional natural gas (MCF per day)	**44,839**	42,336	48,584	46,390
Average price ($ per MCF)	**2.69**	1.16	2.03	2.42
Total BOE per day	**15,254**	14,460	16,399	15,957

STATISTICAL REVIEW

Summary of Gross Oil and Gas Reserves as of December 31, 2025

Reserves Category:	Light & Medium Crude Oil (Mbbl)	Conventional Natural Gas (MMCF)	Natural Gas Liquids (Mbbl)	Oil equivalent[4] (MBOE)	Future development Capital (000s)
PROVED					
Developed Producing	15,419	93,403	3,340	34,326	-
Developed Non-Producing	1,619	7,081	247	3,047	5,681
Undeveloped	23,033	137,204	4,548	50,448	798,583
TOTAL PROVED	**40,071**	**237,688**	**8,136**	**87,821**	**804,264**
PROBABLE	10,001	59,240	2,013	21,888	18,298
TOTAL PROVED PLUS PROBABLE[(1)(2)(3)]	**50,072**	**296,928**	**10,148**	**109,708**	**822,562**

(1) Reserves have been presented on gross basis which are the Company's total working interest share before the deduction of any royalties and without including any royalty interests of the Company.

(2) Totals may not add due to rounding.

(3) Based on average commodity price forecasts of Sproule International Limited ("Sproule ERCE"), GLJ Petroleum Consultants and McDaniels & Associates Consultants Ltd. (the "Price Forecast") dated December 31, 2025

(4) Oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil.

Reconciliation of Company Gross Reserves by Principle Product Type as of December 31, 2025[(1)]

	Light & Medium Crude Oil		Conventional Natural Gas[(3)]		Natural Gas Liquids		Total	
	Total Proved (Mbbl)	Proved + Probable (Mbbl)	Total Proved (MMCF)	Proved + Probable (MMCF)	Total Proved (Mbbl)	Proved + Probable (Mbbl)	Total Proved (MBOE)	Proved + Probable (MBOE)
Opening Balance December 31, 2024	**41,438**	**51,724**	**214,580**	**267,790**	**7,796**	**9,714**	**84,997**	**106,070**
Extensions (1)	2,132	2,826	27,437	35,030	790	1002	7,495	9,666
Acquisitions (2)	762	952	9,605	12,022	196	246	2,559	3,202
Dispositions(3)	(169)	(218)	(32)	(42)	-	-	(175)	(226)
Economic Factors (4)	(834)	(758)	(3,251)	(2,884)	(127)	(106)	(1,503)	(1,345)
Technical Revisions (5)	(917)	(2,112)	5,965	1,627	32	(156)	109	(1,997)
Production	(2,341)	(2,341)	(16,616)	(16,616)	(551)	(551)	(5,662)	(5,662)
Closing Balance, December 31, 2025	**40,071**	**50,072**	**237,688**	**296,928**	**8,135**	**10,148**	**87,821**	**109,708**

(1) Includes the drilling of step-out and infill wells in 2025 and the booking of new step-out future drilling locations.

(2) Additions in volumes relating to the acquisition of an asset in the Greater Bonanza Area.

(3) Reduction in volumes due to the selling of non-core assets. In 2025, operated properties in Saskatchewan and Eastern Alberta were divested in their entirety.

(4) The economic factors reflect the change in reserves due to the changes in the December 31, 2024 Price Forecast and the December 31, 2025 Price Forecast.

(5) Technical revisions are attributable to changes in previously booked estimates. In 2025, positive technical revisions were recorded in developed producing entities, primarily associated with improved well performance, as well as in the majority of pre-booked locations due to improved offset and analogue production performance. Negative technical revisions were recorded in the Montney property related to revisions to pre-booked locations to better align with future development plans and not due to well performance expectations.

(6) Gross Reserves means the Company's working interest reserves before calculation of royalties and before considerations of the Company's royalty interests.

Summary of Net Present Values of Future Net Revenue as of December 31, 2025

($ 000s)	Net Present Value Before Income Taxes Discounted at (% per Year)			
Reserves Category:	**0%**	**5%**	**10%**	**15%**
PROVED				
Developed Producing	749,746	577,152	468,500	396,003
Developed Non-Producing	65,627	47,608	36,640	29,441
Undeveloped	909,732	554,798	354,036	233,462
TOTAL PROVED	**1,725,105**	**1,179,558**	**859,176**	**658,906**
PROBABLE	700,234	437,670	308,892	234,976
TOTAL PROVED + PROBABLE(1)(2)(3)(4)	**2,425,339**	**1,617,228**	**1,168,068**	**893,882**

(1) Evaluated by Sproule ERCE as at December 31, 2025. Net present value of future net revenue does not represent fair value of the reserves.

(2) Net present values equals net present value before income taxes based on average of Sproule ERCE, GLJ Petroleum Consultants and McDaniels & Associates Consultants Ltd. commodity price forecasts dated December 31, 2025. There is no assurance that the forecast price and cost assumptions will be attained and variances could be material.

(3) Includes abandonment and reclamation costs as defined in NI 51-101.

(4) Totals may not add due to rounding.

Finding, Development & Acquisition (FD&A) and Finding & Development (F&D) Costs

	Proved Reserves Net Additions				Proved + Probable Reserves Net Additions			
	2025	2024	2023	3 Yr Avg(4)	2025	2024	2023	3 Yr Avg(4)
FD&A COSTS PER BOE (1)(2)(3)**(5)**								
Including FDC	$10.39	$17.31	$ 39.08	$19.10	$12.37	$18.34	$34.16	$19.54
Excluding FDC	$8.28	$10.43	$27.09	$12.94	$9.02	$11.65	$23.24	$13.17
F&D COSTS PER BOE (1)(2)(3)(5)								
Including FDC	$12.72	$18.86	$39.08	$22.17	$14.93	$20.99	$34.16	$22.95
Excluding FDC	$11.39	$14.85	$27.09	$16.94	$11.47	$16.42	$23.24	$16.81

(1) Barrels of Oil Equivalent may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

(3) The calculation of F&D and FD&A costs both includes or excludes, as labelled, the change in FDC required to bring proved undeveloped and developed reserves into production. The F&D or FD&A number is calculated by dividing the identified capital expenditures by applicable reserve additions including extensions, infills. Revisions, acquisitions and disposals, and economic factors, after or before changes in FDC costs (as labelled).

(4) Three year average is calculated using three year total capital costs and reserve additions on both a TP and TPP reserves on a weighted average basis.

(5) "FD&A Cost" and "F&D Cost", do not have standardized meanings and therefore may not be comparable with the calculation of similar measures for other entities. See "Information Regarding Disclosure" within the Management's Discussion and Analysis.

Commodity Prices Used in the Above Calculations of Reserves are as Follows

Year	Canadian Light sweet crude 40° API ($Cdn per bbl)	Natural Gas AECO-C Spot ($Cdn per mmbtu)	NGL Butanes Edmonton ($Cdn per bbl)	NGL Pentanes Edmonton ($Cdn per bbl)	Operating Cost Inflation Rate (% per Year)	Exchange Rate ($US/$Cdn)
FORECAST (1)(2)						
2026	77.54	3.00	36.95	80.01	0.0	0.73
2027	83.60	3.30	39.79	86.19	2.0	0.74
2028	90.17	3.49	42.87	92.85	2.0	0.74
2029	92.32	3.58	43.89	95.06	2.0	0.74
2030	94.17	3.65	44.77	96.96	2.0	0.74
2031	96.06	3.72	45.66	98.91	2.0	0.74
2032	97.98	3.80	46.58	100.88	2.0	0.74
2033	99.93	3.88	47.51	102.90	2.0	0.74
2034	101.93	3.95	48.46	104.96	2.0	0.74
2035	103.97	4.03	49.43	107.06	2.0	0.74

(1) Crude oil, natural gas and liquid prices escalate at 2.0 percent thereafter.

(2) The forecast of product prices is an average of independent reserve evaluators Sproule ERCE, GLJ Petroleum and McDaniel and Associates Consultants Ltd.

Production

	2025		
	OIL & NGLS (BBL PER DAY)	CONVENTIONAL NATURAL GAS (MCF PER DAY)	TOTAL (BOE PER DAY)
Alberta	7,915	45,418	15,484
Saskatchewan	7	19	11
British Columbia	3	87	18
Total	7,925	45,524	15,513

Land Holdings

Bonterra's holdings of petroleum and natural gas leases and rights are as follows:

	2025		2024	
	Gross Acres	**Net Acres**	Gross Acres	Net Acres
Alberta	**451,455**	**323,051**	408,928	282,482
Saskatchewan	**-**	**-**	5,842	3,704
British Columbia	**67,258**	**30,307**	65,208	28,257
Total	**518,713**	**353,358**	479,978	314,443

Petroleum and Natural Gas Expenditures

The following table summarized petroleum and natural gas capital expenditures incurred by Bonterra on exploration and evaluation costs (land), property, plant and equipment costs, acquisitions and disposals of oil and gas property for the years ended December 31:

($ 000s)	**2025**	2024
Exploration and Evaluation costs	**2,304**	1,190
Property, Plant and Equipment costs	**67,628**	99,886
Acquisitions - Oil and Gas property	**16,030**	24,234
Disposition - Oil and Gas property	**(2,035)**	-
Net Petroleum and Natural Gas Capital Expenditures	**83,927**	125,310

Drilling History

The following tables summarize Bonterra's gross and net drilling activity and success:

	2025					
	Development		**Exploratory**		**Total**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**
Crude oil	17	8.9	-	-	17	8.9
Natural gas	1	1.0	-	-	1	1.0
Total	**18**	**9.9**	**-**	**-**	**18**	**9.9**
Success rate	**100%**	**100%**	**100.0**	**100.0**	**100%**	**100%**

	2024					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	23	18.5	-	-	23	18.5
Natural gas	1	1.0	-	-	1	1.0
Total	24	19.5	-	-	24	19.5
Success rate	100%	100%	100.0	100.0	100%	100%

YEAR END 2025

Management's Discussion and Analysis

&

Financial Statements

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") of the financial position and results of operations of Bonterra Energy Corp. ("Bonterra" or "the Company"), is for the three months and years ended December 31, 2025 and 2024. For a full understanding of the financial position and results of operations of the Company, the MD&A should be read in conjunction with the documents filed on SEDAR+, including historical financial statements, MD&A and the Annual Information Form ("AIF") dated March 12, 2025 for the year ended December 31, 2025. These documents are available at **www.sedarplus.ca**.

Bonterra's management is responsible for the integrity of the information contained in this report and for the consistency between the MD&A and financial statements. In the preparation of these financial statements, estimates are necessary to make a determination of future values for certain assets and liabilities. Management believes these estimates have been based on careful judgments and have been properly presented. The financial statements have been prepared using policies and procedures established by management and fairly reflect Bonterra's financial position and results of operations. The Company's financial statements have been prepared in accordance with International Financial Reporting Standards (IFRS®) as issued by the International Accounting Standards Board (IASB®).

Bonterra's Board of Directors and Audit Committee have reviewed and approved the financial statements and MD&A. This MD&A is dated March 12, 2025.

Description of Business

Bonterra Energy Corp. is one of Canada's longest-standing oil and gas exploration, development, and production companies, with a focus on its core assets in the Cardium, Charlie Lake, and Montney formations within the western Canadian sedimentary basin. The Company is committed to sustainable production growth, financial resilience, and advancing toward a shareholder returns-based model through disciplined capital allocation and operational efficiency.

Bonterra plays a vital role as an economic contributor to rural and northern Alberta communities, fostering positive stakeholder relationships and upholding high standards of environmental and corporate responsibility. Bonterra's common shares are traded on the Toronto Stock Exchange ("TSX") under the symbol "**BNE"** and are also quoted in the United States on the OTCID market under the symbol "**BNEFF**." Investors should be aware that trading on the U.S. OTC market may involve different liquidity, transparency and regulatory standards than trading on Canadian exchanges; accordingly, U.S. quotations may not fully reflect the pricing or trading activity on the TSX.

Frequently Recurring Terms

Bonterra uses the following frequently recurring terms in this MD&A:

- "WTI" refers to West Texas Intermediate, a grade of light sweet crude oil used as benchmark pricing in the United States;
- "MSW Stream Index" or "Edmonton Par" refers to the mixed sweet blend that is the benchmark price for conventionally produced light sweet crude oil in Western Canada;
- "AECO" is the benchmark price for natural gas in Alberta, Canada;
- "bbl" refers to barrel; "NGL" refers to natural gas liquids;
- "MCF" refers to thousand cubic feet;
- "MMBTU" refers to million British Thermal Units;
- "GJ" refers to gigajoule;
- "LNG" refers to liquefied natural gas; and
- "BOE" refers to barrels of oil equivalent.

Disclosure provided herein in respect of a BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Numerical Amounts

The reporting and the functional currency of the Company is the Canadian dollar.

ANNUAL COMPARISONS

As at and for the year ended ($000s except $ per share)		**December 31, 2025**	December 31, 2024	December 31, 2023
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Light oil	-bbl per day	**6,415**	6,639	7,209
	-average price ($ per bbl)	**81.24**	94.35	97.58
NGLs	-bbl per day	**1,511**	1,513	1,359
	-average price ($ per bbl)	**41.61**	46.97	48.80
Conventional natural gas	-MCF per day	**45,524**	40,164	33,814
	-average price ($ per MCF)	**2.09**	1.68	3.12
Total BOE per day		**15,513**	14,846	14,204

(1) Net loss for the year ended December 31, 2025, primarily reflects a one-time debt extinguishment cost of $11.6 million.

(2) On March 1, 2024, the Company acquired the Charlie Lake Assets for cash consideration of $23.6 million and $0.3 million in non-core mineral rights, including closing adjustments. The Charlie Lake Assets has been accounted for as an asset acquisition, which resulted in an increase of $24.2 million in PP&E and the assumption of $0.3 million in decommissioning liabilities.

(3) On December 18, 2025, the Company acquired the Bonanza Assets adjacent to the Company's Charlie Lake area assets for cash considerations of $15.3 million in mineral rights, including closing adjustments. This acquisition has been accounted for as an asset acquisition, which resulted in a $16.0 million increase in PP&E and the assumption of $ 0.7 million in decommissioning liabilities.

QUARTERLY COMPARISONS

As at and for the periods ended ($ 000s except $ per share)	2025 Q4	Q3	Q2	Q1
Financial				
Revenue - oil and gas sales	**57,833**	55,166	64,185	70,690
Funds flow	**22,111**	21,330	23,092	27,635
Per share - basic	**0.61**	0.59	0.63	0.74
Per share - diluted	**0.60**	0.58	0.62	0.73
Cash flow from operations	**21,526**	8,344	29,996	29,614
Per share - basic	**0.60**	0.23	0.81	0.79
Per share - diluted	**0.59**	0.23	0.80	0.78
Net loss	**(4,648)**	(3,554)	(1,313)	(7,610)
Per share - basic and diluted	**(0.13)**	(0.10)	(0.04)	(0.20)
Capital expenditures	**16,348**	14,783	6,351	32,450
Oil and gas property acquisition	**16,029**	-	-	-
Total assets	**959,434**	935,536	949,202	978,798
Net debt	**179,049**	167,803	169,938	186,102
Shareholders' equity	**522,032**	526,565	530,935	533,830
Operations				
Light oil (barrels per day)	**6,274**	6,051	6,794	6,546
NGLs (barrels per day)	**1,507**	1,353	1,508	1,679
Conventional natural gas (MCF per day)	**44,839**	42,336	48,584	46,390
Total BOE per day	**15,254**	14,460	16,399	15,957

	2024			
As at and for the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Financial				
Revenue - oil and gas sales	69,699	69,204	72,465	68,589
Funds flow	30,100	30,066	31,484	27,018
Per share - basic	0.81	0.81	0.84	0.73
Per share - diluted	0.81	0.81	0.84	0.72
Cash flow from operations	28,587	31,531	33,180	21,654
Per share - basic	0.77	0.84	0.89	0.58
Per share - diluted	0.77	0.84	0.89	0.58
Net earnings (loss)	(2,213)	4,258	7,310	848
Per share - basic and diluted	(0.06)	0.11	0.20	0.02
Capital expenditures	22,438	24,095	21,619	32,924
Oil and gas property acquisition	-	-	-	24,234
Total assets	975,043	982,256	984,065	984,464
Net debt	167,210	168,278	172,622	181,400
Shareholders' equity	540,639	542,344	537,498	529,605
Operations				
Light oil (barrels per day)	6,588	6,775	6,571	6,622
NGLs (barrels per day)	1,625	1,538	1,418	1,468
Conventional natural gas (MCF per day)	44,436	42,039	37,519	36,594
Total BOE per day	15,619	15,320	14,242	14,189

Business Environment and Sensitivities

Bonterra's financial results may be influenced by fluctuations in commodity prices, including price differentials, as well as production volumes and foreign exchange rates. The following table depicts selective market benchmark commodity prices, differentials, and foreign exchange rates in the last eight quarters to assist in understanding how past volatility has impacted the Company's financial and operating performance. The increases or decreases in Bonterra's realized average price for oil and natural gas for each of the eight quarters is also outlined in detail in the following table.

	Q4-2025	Q3-2025	Q2-2025	Q1-2025	Q4-2024	Q3-2024	Q2-2024	Q1-2024
Crude oil								
WTI (U.S.$/bbl)	**59.14**	64.93	63.74	71.42	70.27	75.09	80.57	76.96
WTI to MSW Stream Index								
Differential (U.S.$/bbl)[(1)]	**(4.25)**	(2.19)	(2.82)	(5.00)	(2.37)	(3.31)	(3.62)	(8.64)
Foreign exchange								
U.S.$ to Cdn$	**1.3949**	1.3774	1.3840	1.4348	1.3991	1.3636	1.3694	1.3488
Bonterra average realized								
oil price (Cdn$/bbl)	**71.90**	81.92	79.85	91.22	92.11	94.30	102.09	88.96
Natural gas								
AECO (Cdn$/mcf)	**2.22**	0.63	1.68	2.16	1.47	0.68	1.17	2.48
Bonterra average realized								
gas price (Cdn$/mcf)	**2.69**	1.16	2.03	2.42	1.60	0.96	1.64	2.65

(1) This differential accounts for the majority of the difference between WTI and Bonterra's average realized price (before quality adjustments and foreign exchange).

WTI crude oil prices averaged $59.14 per barrel (USD) in the fourth quarter of 2025, representing a 16 percent decrease compared to the same period in 2024. The decline reflects continued volatility in global crude oil markets driven by macroeconomic uncertainty, geopolitical developments and increased global supply. In particular, higher non-OPEC production and OPEC+'s decision to accelerate the return to historical production quotas in 2025 contributed to sustained downward pressure on crude oil benchmark pricing.

In addition to movements in the WTI benchmark, the Company's realized crude oil prices are influenced by the Mixed Sweet Blend ("MSW") stream index, commonly referred to as the Edmonton Par differential (the "Differential"). During the fourth quarter of 2025, the Differential averaged negative $4.25 per barrel (USD), widening by $1.88 per barrel compared to the fourth quarter of 2024. The widening Differential was primarily attributable to record production volumes in the Western Canadian Sedimentary Basin, which resulted in weaker local pricing relative to WTI. While pricing was weaker during the quarter, planned egress expansion projects on the Enbridge Mainline system and the Trans Mountain Expansion ("TMX"), expected to come into service in 2027, are anticipated to improve takeaway capacity from the basin over the longer term.

AECO daily spot natural gas prices averaged $2.22 per Mcf in the fourth quarter of 2025, representing a 51 percent increase compared to the fourth quarter of 2024. The increase was primarily driven by stronger demand, including higher exports to the United States and increased feed gas demand associated with the ramp-up of LNG Canada, as well as reduced maintenance-related outages on intra-basin and downstream export pipelines, which had constrained market access in the prior year period.

The following chart shows the Company's sensitivity to key commodity price variables. The sensitivity calculations are performed independently and show the effect of changing one variable while holding all other variables constant.

Annualized sensitivity analysis on before tax cash flow, as estimated for 2026[1]			
Impact on cash flow	Change ($)	$000s	$ per share[2]
Realized crude oil price ($/bbl)	1.00	2,599	0.07
Realized natural gas price ($/mcf)	0.10	1,765	0.05
U.S.$ to Canadian $ exchange rate	0.01	1,456	0.04

(1) This analysis uses current royalty rates, annualized estimated average production of 16,300 BOE per day and no changes in working capital.

(2) Based on annualized basic weighted average shares outstanding of 36,068,680.

Business Overview, Strategy and Key Performance Drivers

In 2025, Bonterra advanced its strategy of delivering long-term shareholder value through the disciplined development of its high-quality, balanced commodity asset base. During the year, the Company achieved meaningful production growth and completed a financial restructuring that simplified its capital structure, enhanced liquidity, and improved its ability to execute on its capital allocation priorities, including the resumption of shareholder return initiatives.

Bonterra's strategy continues to focus on sustainable free funds flow generation, maintaining balance sheet strength, and allocating capital toward high-return development opportunities while preserving financial flexibility across commodity price cycles.

Normal Course Issuer Bid (NCIB)

As part of its capital allocation framework, Bonterra received approval from the Toronto Stock Exchange on April 11, 2025, to implement a Normal Course Issuer Bid ("NCIB"). Under the NCIB, the Company may repurchase for cancellation up to 3,199,449 common shares, representing approximately 10 percent of its public float, during the period from April 15, 2025 to April 14, 2026.

During the year ended December 31, 2025, Bonterra repurchased 749,900 common shares for cancellation at an average price of $3.56 per share.

Repurchases may be funded through available cash flow or borrowings under the Company's credit facilities and are executed through the TSX or alternative Canadian trading systems at prevailing market prices. Bonterra has also entered into an automatic share purchase plan with an independent broker to provide flexibility during blackout periods. All shares repurchased under the NCIB will be cancelled.

Debt Refinancing and Capital Management

In early 2025, Bonterra completed a series of financing transactions intended to strengthen its balance sheet, reduce refinancing risk, and enhance liquidity.

On January 28, 2025, the Company closed a private placement of $135 million in Senior Secured Second Lien Notes due 2030. Net proceeds were used to repay second lien subordinated term debt and reduce borrowings under the revolving credit facility.

On February 26, 2025, Bonterra redeemed its subordinated debentures in full.

On April 30, 2025, the Company renewed and increased its revolving credit facility to $125 million. The renewed facility includes improved terms, including a wider borrowing base, reduced interest rate spreads, and the removal of financial covenants, providing increased flexibility to support Bonterra's capital program and capital allocation priorities.

Strategic Acquisitions and Development

On December 18, 2025, Bonterra closed the acquisition of petroleum and natural gas assets in northern Alberta for cash consideration of $15.3 million, after closing adjustments (the “Bonanza Asset Acquisition”). The acquisition was funded through the Company’s revolving credit facility and resulted in a $16.0 million increase in property, plant and equipment and the assumption of $0.7 million in decommissioning liabilities.

The acquired assets are located northwest of Grande Prairie, Alberta, and consist of low-decline oil pools under waterflood, producing approximately 760 BOE per day, comprised of approximately 240 barrels per day of light crude oil, 40 barrels per day of natural gas liquids, and 2,885 mcf per day of conventional natural gas. The acquisition expanded Bonterra’s land position by 41 net sections in the Greater Bonanza Area, offsetting existing Charlie Lake operations, and added incremental Charlie Lake drilling inventory, including 21 complementary locations and three low-risk infill opportunities in the Doig formation.

The acquisition also included strategic infrastructure, such as underutilized compression, batteries, and gathering pipelines, which is expected to provide operational synergies and additional development optionality.

Following closing, Bonterra’s revolving credit facility was increased to $150 million, further enhancing liquidity.

Production Growth and Operational Highlights

Bonterra averaged 15,513 BOE per day during 2025, representing a 5 percent increase from 14,846 BOE per day in the prior year. The increase was primarily attributable to the execution of the Company’s 2025 drilling program and well reactivation activities completed early in the year, which contributed to four consecutive quarters of record production through the first half of 2025.

Bonterra continues to maintain its revised annual production guidance of 16,200 to 16,400 BOE per day and capital expenditure guidance of $75 to $80 million. The Company also retains capital flexibility for the remainder of the year in response to prevailing commodity price conditions.

Charlie Lake

The Company entered 2026 with one three-mile (0.9 net) DUC well and has since drilled an additional 3 (2.8 net) Charlie Lake wells. The DUC well and two of the new Charlie Lake drills have been completed, tied-in and are in the early stages of cleaning up post completion operations, while the third new Charlie Lake well is planned to be completed before the end of March and tied-in early in the second quarter. The Company anticipates having 30-day peak rate on new results in its next quarterly release. Net production from the Charlie Lake asset in December 2025 was approximately 3,660 BOE per day (41% light oil and NGLs), representing 23 percent of the total production for the month of December 2025.

Montney

The Montney remains a strategic asset in the Company's portfolio for enhancing shareholder value. Based on the strong production results to date from its two operated wells Bonterra has drilled its third Montney well to continue the delineation of its Montney land base. The third well was drilled in Q4 2025 and was completed and tied-in in Q1 of 2026. The well is a three-mile horizontal and was completed with an increased fracture stimulation intensity compared to Bonterra’s previous two Montney wells. The new Montney well is in the early stages of cleaning up post completion operations. The Company anticipates having 30-day peak rate results in its next quarterly release. Net production from the Montney asset in December 2025 was approximately 780 BOE per day (43% light oil and NGLs) representing 5 percent of the total production for the month of December 2025.

Capital Expenditures and Environmental Stewardship

Capital expenditures totaled $69.9 million in 2025. Of this amount, $37.8 million was directed to the drilling of nine gross (8.4 net) operated wells, seven gross (6.5 net) of which were completed, equipped and brought on production during the year. The remaining two gross (1.9 net) operated wells were tied-in in the first quarter of 2026. The Company also invested $3.2 million in nine gross (1.5 net) non-operated wells, covering its working interest share of drilling, completion, equipping and tie-in costs. The balance of $28.9 million was allocated to land and lease acquisitions, infrastructure projects, recompletions, compressor upgrades at major gas plants in the Cardium area, and the construction of a new battery and water disposal well to support ongoing development in the northern area of the Charlie Lake play.

Bonterra remains committed to responsible operations and environmental stewardship. In 2025, the Company invested $7.1 million toward reducing its decommissioning liabilities, exceeding the mandatory expenditure requirements under the Alberta Energy Regulator’s Liability Management Program. During the year, the Company abandoned 28.6 net wells and 26.4 net pipelines totaling 25.1 kilometres in length, completed decommissioning activities on 173.9 net well sites in preparation for future reclamation, and undertook initial reclamation on 12.5 net well sites. The Company expects to invest approximately $8.0 million in decommissioning activities in 2026, which is anticipated to again exceed the mandatory spending requirements under the Alberta Energy Regulator’s Liability Management Program.

Risk Management and Commodity Pricing

To protect future cash flows, Bonterra has secured physical delivery sales and risk management contracts for approximately 48% of its expected crude oil production and 25% of its natural gas production over the first six months of 2026.

During this period, the Company has secured WTI prices between $55.00 USD and $80.95 USD per barrel for 3,044 barrels per day. For natural gas, Bonterra has locked in prices between $1.29 and $3.30 per GJ for 12,743 GJ per day.

In addition, Bonterra has secured WTI pricing between $60.00 USD and $66.75 USD per barrel on 2,250 barrels per day, representing 33% of expected crude oil production for the second half of 2026. Natural gas prices averaging $2.76 per GJ for 8,474 GJ per day have also been secured covering the second half of 2026 and the first quarter of 2027, primarily through fixed-price contracts.

Key Performance Drivers

The Company’s successful operations are dependent upon several factors including, but not limited to commodity prices, efficient management of capital spending, the ability to maintain desired production levels, control over infrastructure, efficiency in developing and operating properties, and the ability to control costs. Its key performance measures include average daily production volumes, realized prices, and production costs per unit. Disclosure of these key performance measures can be found within this MD&A and/or previous interim or annual MD&A disclosures.

Production

	Three months ended			Year ended	
	December 31, 2025	September 30, 2025	December 31, 2024	**December 31, 2025**	December 31, 2024
Light oil (barrels per day)	**6,274**	6,051	6,588	**6,415**	6,639
NGLs (barrels per day)	**1,507**	1,353	1,625	**1,511**	1,513
Conventional natural gas (MCF per day)	**44,839**	42,336	44,436	**45,524**	40,164
Average BOE per day	**15,254**	14,460	15,619	**15,513**	14,846

The Company's production in 2025 averaged 15,513 BOE per day, representing a 5 percent increase compared to the same period in 2024. The increase was primarily driven by new Charlie Lake well additions and the successful execution of a Pembina Cardium well reactivation program early in the year.

On a quarter-over-quarter basis, production increased by 794 BOE per day, reflecting contributions from two gross (1.8 net) Charlie Lake wells brought on production at the end of October, as well as a partial-period contribution averaging 760 BOE per day during the 14-day period following the acquisition of the Bonanza assets on December 18, 2025.

In addition, Q3 2025 production included approximately 300 BOE per day of shut-in volumes due to unplanned downtime from third-party outages, along with the temporary shut-in of higher-gas wells in response to weak natural gas pricing during September.

Cash Netback

	Three months ended			Year ended	
$ per BOE	**December 31, 2025**	September 30, 2025	December 31, 2024	**December 31, 2025**	December 31, 2024
Production volumes (BOE)	**1,403,369**	1,330,294	1,436,969	**5,662,146**	5,433,622
Gross production revenue	**41.21**	41.47	48.50	**43.78**	51.52
Realized gain on risk management contracts	**1.11**	0.37	1.13	**0.52**	0.66
Royalties	**(4.37)**	(5.27)	(6.62)	**(5.56)**	(7.30)
Production costs	**(15.98)**	(16.41)	(16.07)	**(16.69)**	(16.54)
Field netback	**21.97**	20.16	26.94	**22.05**	28.34
General and administrative	**(4.70)**	(2.18)	(3.62)	**(2.84)**	(2.65)
Adminstrative and investment income	**0.10**	0.09	0.09	**0.09**	0.11
Disposal of investments	**-**	-	-	**-**	0.27
Interest	**(3.02)**	(3.13)	(3.00)	**(2.97)**	(3.28)
Current income tax	**1.41**	1.09	0.54	**0.30**	(0.95)
Cash netback	**15.76**	16.03	20.95	**16.63**	21.84

In 2025, field netbacks declined on a per BOE basis relative to the same period in 2024, primarily due to lower commodity prices. This impact was partially offset by a 6 percent reduction in total pre-tax costs, which decreased by $1.88 per BOE. Total pre-tax costs include royalties, production expenses, general and administrative costs, and interest.

Oil and Gas Sales

	Three months ended			Year ended	
	December 31, 2025	September 30, 2025	December 31, 2024	**December 31, 2025**	December 31, 2024
Revenue - oil and gas sales ($ 000s)					
Light oil	**41,505**	45,602	55,826	**190,215**	229,249
NGL	**5,214**	5,031	7,323	**22,946**	26,011
Conventional natural gas	**11,114**	4,533	6,550	**34,713**	24,697
	57,833	55,166	69,699	**247,874**	279,957
Average realized prices:					
Light oil ($ per barrel)	**71.90**	81.92	92.11	**81.24**	94.35
NGL ($ per barrel)	**37.61**	40.42	48.97	**41.61**	46.97
Conventional natural gas ($ per MCF)	**2.69**	1.16	1.60	**2.09**	1.68
Average ($ per BOE)	**41.21**	41.47	48.50	**43.78**	51.52
Average BOE per day	**15,254**	14,460	15,619	**15,513**	14,846

Revenue from oil and gas sales in 2025 decreased by $32.1 million, or 11.5 percent, as compared to the same period in 2024. This decrease was primarily driven by a 15 percent reduction in Bonterra's average realized commodity prices, partially offset by a 4 percent increase in production over the same period. Quarter-over-quarter revenue from oil and gas sales increased 5 percent primarily due to an increase in production.

Bonterra's product split on a revenue basis was weighted approximately 86 percent to crude oil and NGLs during 2025.

Royalties

	Three months ended			Year ended	
($ 000s)	**December 31, 2025**	September 30, 2025	December 31, 2024	**December 31, 2025**	December 31, 2024
Crown royalties	**4,259**	4,910	6,727	**22,453**	27,633
Freehold, gross overriding and other royalties	**1,876**	2,104	2,784	**9,050**	12,009
Total royalties	**6,135**	7,014	9,511	**31,503**	39,642
Crown royalties - percentage of revenue	**7.4**	8.9	9.7	**9.1**	9.9
Freehold, gross overriding and other royalties - percentage of revenue	**3.2**	3.8	4.0	**3.7**	4.3
Royalties - percentage of revenue	**10.6**	12.7	13.7	**12.8**	14.2
Royalties $ per BOE	**4.37**	5.27	6.62	**5.56**	7.30

Bonterra's royalty obligations include Crown royalties (paid to the provinces of Alberta and British Columbia), as well as freehold, gross overriding, and other royalties. Following the divestment of its Saskatchewan assets in Q1 2025, the Company no longer incurs Crown royalties in that province.

Total royalties per BOE decreased in 2025 compared to the prior year, primarily due to weaker crude oil prices.

Production Costs

	Three months ended			Year ended	
($ 000s except $ per BOE)	**December 31, 2025**	September 30, 2025	December 31, 2024	**December 31, 2025**	December 31, 2024
Production costs	**22,425**	21,825	23,089	**94,500**	89,881
$ per BOE	**15.98**	16.41	16.07	**16.69**	16.54

Production costs for 2025 increased on a BOE basis as compared to 2024 primarily driven by initial third-party infrastructure charges related to the Charlie Lake and Montney plays, along with higher activity levels from the Company's well reactivation program. These increases were partially offset by a 29 percent reduction in power rates and a decrease in facility and pipeline maintenance in the Cardium play.

Q4 2025 compared to Q3 2025, production costs per BOE decreased, primarily due to less road maintenance in the fourth quarter.

Other Income

($ 000s)	**December 31, 2025**	Three months ended September 30, 2025	December 31, 2024	Year ended **December 31, 2025**	December 31, 2024
Investment income	**48**	87	46	**319**	326
Administrative income	**79**	44	75	**237**	252
Gain on sale of property	**-**	1,077	25	**4,634**	178
Deferred consideration	**243**	214	276	**955**	958
Realized gain on risk management contracts	**1,556**	494	1,626	**2,942**	3,569
Unrealized gain (loss) on risk management contracts	**613**	(13)	(2,707)	**1,260**	(1,525)
	2,539	1,903	(659)	**10,347**	3,758

The Company receives administrative income for various oil and gas administrative services provided and production equipment rentals to other companies.

The Company disposed of certain non-core oil and gas assets primarily located in Saskatchewan for total consideration of $2.2 million, including closing adjustments. The consideration consisted of $2.1 million in cash and $0.1 million in non-core mineral rights. The transaction resulted in a gain on sale of property of $4.6 million. As part of the disposition, decommissioning liabilities of approximately $3.8 million associated with the assets were also derecognized.

Deferred consideration relates to a deferred gain on the sale of a two percent overriding royalty interest, which is recognized into revenue using the same unit-of-production method as the encumbered property, plant, and equipment assets.

To minimize commodity price risk on crude oil and natural gas sales, Bonterra has entered into financial derivatives. The financial derivatives outstanding are primarily for the period from January 1, 2026 to September 30, 2026 and are for a total of 758,000 barrels of light crude oil (approximately 2,777 barrels of oil per day) at fixed WTI prices ranging from $55.00 USD to $80.95 USD per barrel. In addition, the Company has entered into financial derivatives on natural gas prices between $1.75 and $2.70 on 5,000 GJ per day for the period from January 1, 2026 to March 31, 2026. These contracts are not considered normal sales contracts and are recorded at fair value.

General and Administrative ("G&A") Expense

($ 000s except $ per BOE)	**December 31, 2025**	Three months ended September 30, 2025	December 31, 2024	Year ended **December 31, 2025**	December 31, 2024
Employee compensation	**5,108**	1,724	3,873	**10,455**	9,111
Office and administrative	**1,483**	1,180	1,334	**5,601**	5,262
Total G&A	**6,591**	2,904	5,207	**16,056**	14,373
$ per BOE	**4.70**	2.18	3.62	**2.84**	2.65

Employee compensation increased in 2025 compared to the same period in 2024, reflecting changes in overall compensation-related accruals primarily in the fourth quarter of 2025.

Office and administrative expenses increased year over year, reflecting the associated costs with the head office relocation. Quarter-over-quarter increased due to additional costs associated with the Bonanza asset acquisition and the increase in the Company's revolving credit facility borrowing base capacity from $125 to $150 million.

Finance Costs

($ 000s except $ per BOE)	Three months ended **December 31, 2025**	September 30, 2025	December 31, 2024	Year ended **December 31, 2025**	December 31, 2024
Interest on bank debt	**688**	618	1,153	**2,505**	3,970
Subordinated notes	**3,544**	3,544	-	**12,994**	-
Subordinated debentures	**-**	-	1,327	**826**	5,310
Subordinated term debt	**-**	-	1,834	**512**	8,541
Interest expense	**4,232**	4,162	4,314	**16,837**	17,821
$ per BOE	**3.02**	3.13	3.00	**2.97**	3.28
Accretion of decommissioning liabilities	**1,131**	961	953	**3,970**	3,692
Accretion on subordinated notes	**249**	249	-	**807**	-
Accretion on subordinated debentures	**-**	-	909	**537**	3,287
Accretion on subordinated term debt	**-**	-	392	**121**	1,732
Total finance costs	**5,612**	5,372	6,568	**22,272**	26,532

Interest on bank debt was lower in 2025 compared to 2024, primarily due to a reduction in bank debt following a comprehensive debt refinancing.

In the first quarter of 2025, the Company completed a private placement of second lien Subordinated Notes, generating gross proceeds of $135 million. The proceeds were used to repay the Subordinated Term Debt, which resulted in a loss on extinguishment of debt of $5.5 million. This included a $3.4 million early redemption fee and $2.1 million of accelerated unamortized issue costs. Remaining funds were used to reduce borrowings under the Company's revolving first lien credit facility (bank debt) and to cover transaction costs.

Additionally, Bonterra redeemed its subordinated debentures, incurring a redemption premium of $3.5 million and $2.6 million in accelerated unamortized issue costs. These were also recognized in the loss on extinguishment of debt, bringing the total extinguishment cost to $11.6 million comprising of $6.8 million in cash payments and $4.7 million in non-cash accretion.

For more information on Subordinated Notes or the repayment of Subordinated Term Debt and Subordinated Debentures, refer to Note 9 of the December 31, 2025, audited annual financial statements.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by approximately $314,000. For more information on bank debt and Subordinated Notes, see the Liquidity and Capital Resources section herein.

Share-Based Compensation

($ 000s)	Three months ended **December 31, 2025**	September 30, 2025	December 31, 2024	Year ended **December 31, 2025**	December 31, 2024
Share-based compensation	**204**	394	508	**2,513**	2,293

Share-based compensation is a statistically calculated value representing the estimated expense of issuing employee stock options and the fair value of share awards at grant comprised of restricted share units (RSUs) and deferred share units (DSUs). The Company records a compensation expense over the vesting period based on the fair value of options and share awards granted to directors, officers, and employees.

During the year ended December 31, 2025, 1,715,500 stock options were forfeited or expired prior to their original expiry dates, primarily due to employee departures and changes to the Company’s long-term incentive structure. The early expiry of these options resulted in a $0.6 million recovery of share-based compensation expense.

Based on the outstanding options and share awards as of December 31, 2025, the Company has an unamortized expense of $2.0 million, of which $1.5 million will be recognized in 2026 and $0.5 million thereafter. For more information about options and share awards issued and outstanding, refer to Note 12 of the December 31, 2025, audited annual financial statements.

Depletion and Depreciation

	Three months ended			Year ended	
($ 000s)	**December 31, 2025**	September 30, 2025	December 31, 2024	**December 31, 2025**	December 31, 2024
Depletion and depreciation	**25,373**	24,031	26,826	**101,594**	97,137

The provision for depletion and depreciation ("D&D") increased due to an increase in production from the same period in 2024. There were no indicators of impairment identified for each of the periods ended.

Taxes

The Company recorded a total income tax recovery of $4.7 million in 2025 (2024 – $3.7 million expense). The increase in income tax recovery as compared to 2024 is primarily due to a net loss before income taxes from the extinguishment of debt costs and lower crude oil prices. As a result, the Company expects to receive an income tax refund of approximately $8.0 million, of which approximately $6.0 million relates to income tax installments paid during 2025. For additional information regarding income taxes, see Note 11 of the December 31, 2025, audited annual financial statements.

Net Earnings (Loss)

	Three months ended			Year ended	
($ 000s except $ per share)	**December 31, 2025**	September 30, 2025	December 31, 2024	**December 31, 2025**	December 31, 2024
Net earnings (loss)	**(4,648)**	(3,554)	(2,213)	**(17,125)**	10,203
$ net earnings (loss) per share - basic	**(0.13)**	(0.10)	(0.06)	**(0.47)**	0.27
$ net earnings (loss) per share - diluted	**(0.13)**	(0.10)	(0.06)	**(0.46)**	0.27

Net earnings for 2025 were $27.3 million lower than the same period in 2024. The decline was mainly driven by lower commodity prices, one-time debt extinguishment costs related to refinancing, and higher depletion and depreciation, and production expenses tied to increased activity levels. These impacts were partly offset by a gain on the sale of property and an income tax recovery.

Funds Flow and Cash Flow From Operations

($ 000s except $ per share)	Three months ended **December 31, 2025**	 September 30, 2025	 December 31, 2024	Year ended **December 31, 2025**	 December 31, 2024
Funds flow	**22,111**	21,330	30,100	**94,168**	118,668
$ per share - basic	**0.61**	0.59	0.81	**2.57**	3.18
$ per share - diluted	**0.60**	0.58	0.81	**2.55**	3.18
Cash flow from operations	**21,526**	8,344	28,587	**89,480**	114,952
$ per share - basic	**0.60**	0.23	0.77	**2.44**	3.08
$ per share - diluted	**0.59**	0.23	0.77	**2.43**	3.08

Funds flow for 2025 decreased by $24.5 million compared to the same period in 2024, primarily due to lower crude oil prices in the last three quarters of 2025. These decreases were partially offset by a lower current income tax provision.

Cash flow from operating activities decreased by $25.5 million over the same period, primarily due to a reduction in non-cash working capital and lower funds flow. On a quarter-over-quarter basis, cash flow from operating activities increased mainly due to increased decommissioning expenditures and, lower non-cash working capital in Q3 2025. The latter largely reflects the semi-annual $7 million interest payment on the subordinated notes made in July 2025, reduced third-party gas processing and the payment of annual property taxes.

Liquidity and Capital Resources

Net Debt to EBITDA

Bonterra continues to focus on reducing overall debt while managing its cash flow and capital expenditures. The Company's net debt to twelve-month trailing EBITDA ratio as of December 31, 2025 was 1.6 (versus 1.2 at December 31, 2024).

The increase in Bonterra's net debt to EBITDA ratio is primarily due to an increase in debt from the Bonanza Asset Acquisition, the one-time costs associated with the debt refinancing transaction and a decrease in EBITDA from lower crude oil prices. To provide cashflow protection, the Company has hedged approximately 40 percent of its forecasted oil and 25 percent of its forecasted natural gas production over the next nine months.

For more information about net debt to EBITDA, please see Note 16 of the December 31, 2025, audited annual financial statements.

Working Capital Deficiency and Net Debt

($ 000s)	**December 31, 2025**	December 31, 2024
Working capital deficiency	**2,614**	29,377
Bank debt	**40,722**	46,211
Subordinated debentures	**-**	55,872
Subordinated term debt (long-term portion)	**-**	35,750
Subordinated notes	**135,713**	-
Net debt	**179,049**	167,210

Net debt is a combination of bank debt, subordinated notes, subordinated debentures, subordinated term debt and working capital. The Company's Bank Facility has a maturity date of April 30, 2027, and is recorded as a long-term liability at December 31, 2025 and December 31, 2024.

Working capital is calculated as current assets less current liabilities.

Financial Risk Management

Bonterra faces market risk related to the oil and gas it produces. This risk is influenced by external factors such as global supply and demand. External factors beyond the Company's control may affect the marketability of oil and gas produced. Oil prices are affected by worldwide supply and demand fundamentals and access to market, while natural gas prices are largely affected by North American supply and demand fundamentals.

To manage commodity risk, the Company executed physical delivery sales contracts which are considered normal sales contracts and are not recorded at fair value in the financial statements, and also executed risk management contracts which are not considered normal sales contracts and are recorded at fair value. The Company has contracts in place on approximately 40% of its expected crude oil production and 25% of its natural gas production, through the next nine months of 2026.

The Company relies on its cash flow, access to equity markets and bank financing to support its operations and capital program. Bonterra uses these futures contracts to hedge its exposure to the potential adverse impact of commodity price volatility and provide a measure of stability to the Company's capital development program. For more information on physical delivery and risk management contracts in place, see Note 16 of the December 31, 2025 annual audited financial statements.

Capital Expenditures

($ 000s)	**December 31, 2025**	December 31, 2024
Exploration and Evaluation		
Land and lease	**2,443**	1,190
Property, Plant and Equipment		
Operated drilling, completing and equipping costs	**37,785**	69,062
Infrastructure, recompletions and other	**26,486**	29,118
Non-operated capital	**3,218**	1,706
	67,489	99,886
Total capital expenditures	**69,932**	101,076

During 2025, the Company incurred capital expenditures of $69.9 million (December 31, 2024 – $101.1 million). Of this amount, $41.0 million was allocated to the drilling of eighteen gross (9.9 net) wells, of which sixteen gross (8.0 net) wells were completed, equipped, and tied-in. Two (1.9 net) remaining wells were tied-in during the first quarter of 2026. An additional $28.9 million was directed toward land and lease acquisitions, infrastructure, recompletions, compressor upgrades at major gas plants in the Cardium area and the construction of a new battery and water disposal well to support development in the northern area of the Charlie Lake play.

Drilling Statistics

	Three months ended						Year ended			
	December 31, 2025		September 30, 2025		December 31, 2024		**December 31, 2025**		December 31, 2024	
	Gross[(1)]	**Net[(2)]**	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	**Gross[(1)]**	**Net[(2)]**	Gross[(1)]	Net[(2)]
Cardium oil horizontal-operated	**-**	**-**	-	-	-	-	**2**	**2.0**	15	14.3
Cardium oil horizontal-non-operated	**2**	**0.5**	2	0.3	-	-	**9**	**1.5**	4	0.6
Charlie Lake oil horizontal-operated	**-**	**-**	3	2.7	-	-	**6**	**5.4**	4	3.6
Montney gas horizontal-operated	**1**	**1.0**	-	-	1	1.0	**1**	**1.0**	1	1.0
Total	**3**	**1.5**	5	3.0	1	1.0	**18**	**9.9**	24	19.5
Success rate		**100%**		100%		100%		**100%**		100%

(1) "Gross" wells are the number of wells in which Bonterra has a working interest.
(2) "Net" wells are the aggregate number of wells obtained by multiplying each gross well by Bonterra's percentage of working interest.

Decommissioning Liabilities

The Company spent $7.1 million on decommissioning activities during the year ended December 31, 2025 (December 31, 2024 - $7.2 million). For 2026, the Company plans to invest approximately $8.0 in decommissioning liabilities, exceeding its $5.5 million mandatory spend requirements under the Alberta Energy Regulator's Liability Management Program.

Bank Debt and Subordinated Notes

Bank debt represents the outstanding amounts drawn on the Company's Bank Facility. As at December 31, 2025, the Company has a total Bank Facility of $150.0 million, comprised of a $125.0 million syndicated revolving credit facility and a $25.0 million non-syndicated revolving facility. The amount drawn under the total Bank Facility at December 31, 2025 was $40.7 million (December 31, 2024 - $46.2 million).

The amounts borrowed under the total Bank Facility bear interest at a floating rate based on the applicable Canadian prime rate or CORRA rate, plus between 2.00 percent and 6.25 percent, depending on the type of borrowing and the Company's consolidated debt to EBITDA ratio. As at December 31, 2025, the terms of the total revolving Bank Facility provided that the loan facility was revolving to April 30, 2026, with a maturity date of April 30, 2027, with no set terms of repayment on the credit facility. In addition, all financial covenants have been removed.

The amount available for borrowing under the Bank Facility is reduced by outstanding letters of credit. Letters of credit totaling $2.1 million were issued as at December 31, 2025 (December 31, 2024 - $2.0 million). Security for the Bank Facility consists of various floating demand debentures totaling $750 million (December 31, 2024 - $750 million) over all of the Company's assets and a general security agreement with first ranking over all personal and real property.

The Company has 135,000 (December 31, 2024 - $Nil) Senior Secured Second Lien Notes ("Subordinated Notes" or the "Notes") outstanding. Each unit consists of one Note with a par value of $1,000, bearing interest at a fixed annual rate of 10.5%, payable semi-annually on January 28 and July 28, commencing July 28, 2025. The Notes mature on January 28, 2030.

The Notes are non-callable by the Corporation prior to January 28, 2028. On or after January 28, 2028, the Corporation may redeem all or part of the Notes at the redemption prices set forth below, plus any accrued and unpaid interest, for the twelve-month period beginning on:

I. January 28, 2028: 102.625%
II. January 28, 2029 and thereafter: 100.000%

Based on the calculated fair value of the Notes as at December 31, 2025, the effective interest rate was determined to be 11.4 percent, by discounting future payments of interest and principal with the residual value allocated to issue costs. The value of the debt will accrete up to the principal balance at maturity.

The Notes are secured by a second lien charge over all personal and real property of the Company, ranking behind the Company's first lien credit facilities.

For more information about Bank Debt and Subordinated Notes, please see Note 8 and 9, respectively, of the December 31, 2025 audited annual financial statements.

Shareholders' Equity

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

	December 31, 2025		December 31, 2024	
Issued and fully paid - common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**37,324,880**	**783,366**	37,253,252	783,185
Issued pursuant to the Company's share option plan	**-**	**-**	71,628	50
Transfer from contributed surplus to share capital	**-**	**-**	-	131
Purchase of common shares in trust	**(506,300)**	**(1,328)**	-	**-**
Repurchase of common shares	**(749,900)**	**(2,667)**	-	-
Balance, end of year	**36,068,680**	**779,371**	37,324,880	783,366

The Company is also authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable Preferred Shares or Class "B" Preferred Shares.

Bonterra's share-based compensation program provides for share awards comprised of Restricted Share Units (RSUs) that vest evenly over three years from the grant date, while Deferred Share Units (DSUs), granted to non-employee directors, vest quarterly and are settled after the director departs the Board.

Although the Company has discretion to settle awards in cash or shares, it intends to settle all RSUs and DSUs in common shares purchased on the open market, and the plans are accounted for as equity-settled under IFRS.

The Company's share-based compensation program also provides a stock option plan for its directors, officers and employees. Under the plan, the Company may grant options for up to 3,657,498 (December 31, 2024 – 3,732,488) common shares. The exercise price of each option granted will not be lower than the market price of the common shares on the date of grant and the option's maximum term is five years.

For additional information regarding share-based compensation outstanding, see Note 12 of the December 31, 2025, audited annual financial statements.

Quarterly Financial Information

	2025			
For the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1
Revenue - oil and gas sales	**57,833**	55,166	64,185	70,690
Cash flow from operations	**21,526**	8,344	29,996	29,614
Net loss	**(4,648)**	(3,554)	(1,313)	(7,610)
Per share - basic	**(0.13)**	(0.10)	(0.04)	(0.20)
Per share - diluted	**(0.13)**	(0.10)	(0.04)	(0.20)

	2024			
For the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Revenue - oil and gas sales	69,699	69,204	72,465	68,589
Cash flow from operations	28,587	31,531	33,180	21,654
Net earnings (loss)	(2,213)	4,258	7,310	848
Per share - basic	(0.06)	0.11	0.20	0.02
Per share - diluted	(0.06)	0.11	0.20	0.02

Quarter-to-quarter fluctuations in the Company's revenue and net earnings are primarily driven by changes in production volumes and realized commodity prices, as well as the resulting impacts on royalties, production expenses, general and administrative costs, and finance costs. The net loss in the first quarter of 2025 was primarily attributable to a one-time debt extinguishment charge of $11.6 million. Net losses in the final three quarters of 2025 were mainly due to lower realized commodity prices.

Contractual Obligations and Commitments

At December 31, 2025, the Company has the following contractual obligations and commitments:

($ 000s)	Less than 1 year	Over 1 year to 3 years	Over 3 years to 5 years	Over 5 years to 7 years	Total
Accounts payable and accrued liabilities	37,136	-	-	-	37,136
Bank debt	-	40,722	-	-	40,722
Subordinated notes	-	-	135,000	-	135,000
Future interest	14,175	28,350	15,356	-	57,881
Firm service commitments	1,246	1,932	912	153	4,243
Office lease commitments	1,140	1,684	1,638	-	4,462
Total	53,697	72,688	152,906	153	279,444

Off-Balance Sheet Financing

Bonterra does not have any guarantees or off-balance sheet arrangements that have been excluded from the annual statement of financial position or balance sheet other than commitments disclosed in Note 17 of the December 31, 2025 audited annual financial statements.

Critical Accounting Estimates

There have been no changes to the Company's critical accounting policies and estimates as of the period ended in the financial statements.

Assessment of Business Risk

Bonterra's exploration and production activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies. Bonterra is subject to a number of risks that are also common to other organizations involved in the oil and gas industry.

Such risks include finding and developing oil and gas reserves at economic costs; estimating amounts of recoverable reserves; production of oil and gas in commercial quantities; marketability of oil and gas produced; fluctuations in commodity prices; stock market volatility; debt servicing which may limit the market price of shares; financial and liquidity risks; environmental and safety risks; failure to realize benefits of acquisitions and dispositions; reliance on third party gathering, processing and pipeline systems; changes to applicable royalty regimes and environmental legislation and regulations; cyber security risks; and reliance on key personnel.

The Company mitigates its risk related to producing hydrocarbons through the utilization of hedging a portion of product sales, current technology and information systems. In addition, Bonterra strives to operate the majority of its properties, thereby maintaining operational control where possible.

Additional information regarding risk factors including, but not limited to, business risks is available in the Company's Annual Information Form for the year ended December 31, 2025, which can be accessed on its website www.bonterraenergy.com or on SEDAR+ at www.sedarplus.ca.

Environmental Risk

General Risks

Oil and gas exploration and production can involve environmental risks such as litigation, physical and regulatory risks. Physical risks include the pollution of the environment, climate change and destruction of natural habitats, as well as safety risks such as personal injury or damage to production facilities and equipment. The Company conducts its operations while ensuring it protects the environment, various stakeholders, and the general public.

Bonterra maintains current insurance coverage that includes comprehensive general liability, limited pollution liability, business interruption and cybersecurity protection. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, availability, as well as industry standards and government regulations. Without such insurance, and if the Company becomes subject to environmental liabilities, the payment of such liabilities could reduce or eliminate its available funds or could exceed the funds the Company has available and result in financial distress.

Climate Change Risks

Bonterra's exploration and production facilities and other operations and activities emit greenhouse gases ("GHG") which require the Company to comply with Federal and/or Provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate Bonterra's effects.

The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on the Company's business, financial condition, results of operations and prospects. Some of its significant facilities may ultimately be subject to future regional, Provincial and/or Federal climate change regulations to manage GHG emissions. In addition, climate change has been linked to long-term shifts in climate patterns and extreme weather conditions, both of which pose the risk of causing operational difficulties.

Additional information regarding risk factors including, but not limited to, environmental risks is available in the Company's Annual Information Form for the year ended December 31, 2025, which can be accessed on its website at www.bonterraenergy.com or on SEDAR+ at www.sedarplus.ca.

Forward-Looking Information

Certain statements contained in this MD&A include statements which contain words such as "anticipate", "could", "should", "expect", "seek", "may", "intend", "likely", "will", "believe" and similar expressions, relating to matters that are not historical facts, and such statements of our beliefs, intentions and expectations about development, results and events which will or may occur in the future, constitute "forward-looking information" within the meaning of applicable Canadian securities legislation and are based on certain assumptions and analysis made by us derived from our experience and perceptions.

Forward-looking information in this MD&A includes, but is not limited to: estimated production; cash flow sensitivity to commodity price variables; earnings sensitivity to interest rates; abandonment and reclamation activities and targets; expected cash provided by continuing operations; plans relating to repayment of indebtedness and share buybacks; future capital expenditures, including the amount and nature thereof; oil and natural gas prices and demand; expansion and other development trends of the oil and gas industry; business strategy and outlook; expansion and growth of our business and operations; maintenance of existing customer, supplier and partner relationships; supply channels; accounting policies; and other such matters.

All such forward-looking information is based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. The risks, uncertainties, and assumptions are difficult to predict and may affect operations, and may include, without limitation: foreign exchange fluctuations; equipment and labour shortages and inflationary costs; general economic conditions; industry conditions; the impact on the Canadian energy industry of U.S. tariffs, changes to international trade agreements or the potential imposition of tariffs or other protectionist economic policies by the Canadian federal or provincial governments; applicable environmental, taxation and other laws and regulations as well as how such laws and regulations may limit growth or operations within the oil and gas industry; the impact of climate-related financial disclosures on financial results; the ability of the Company to raise capital, maintain its syndicated bank facility and refinance indebtedness upon maturity; the effect of weather conditions on operations and facilities; the existence of operating risks; volatility of oil and natural gas prices; oil and gas product supply and demand; risks inherent in the ability to generate sufficient cash flow from operations to meet current and future obligations; increased competition; stock market volatility; credit risks; climate change risks; cyber security; opportunities available to or pursued by us; and other factors, many of which are beyond our control. The foregoing factors are not exhaustive.

Actual results, performance or achievements could differ materially from those expressed in, or implied by, this forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do, what benefits will be derived therefrom. Except as required by law, Bonterra disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise. The forward-looking information contained herein is expressly qualified by this cautionary statement.

Disclosure Controls and Procedures

Disclosure controls and procedures ("DC&P"), as defined in National Instrument 52-109 Certification of Disclosure in Issuers' Annual and Interim Filings, are designed to provide reasonable assurance that information required to be disclosed in the Company's annual filings, interim fillings or other reports filed, or submitted by the Company under securities legislation is recorded, processed, summarized and reported within the time periods specified under securities legislation and include controls and procedures designed to ensure that information required to be disclosed is accumulated and communicated to management, including the Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. The Chief Executive Officer and Chief Financial Officer of Bonterra evaluated the effectiveness of the design and operation of the Company's DC&P. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that Bonterra's DC&P were effective at December 31, 2025.

Internal Controls Over Financial Reporting

Internal control over financial reporting ("ICFR"), as defined in National Instrument 52-109, includes those policies and procedures that:

1. Pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect transactions and dispositions of Bonterra;
2. Are designed to provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles and that receipts and expenditures of Bonterra are being made in accordance with authorizations of management and Directors of Bonterra; and
3. Are designed to provide reasonable assurance regarding prevention or timely detection of authorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

The CEO and CFO have designed, or caused to be designed under their supervision, ICFR as defined in National Instrument 52-109 of the Canadian Securities Administrators, in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS. The control framework the Company used to design its ICFR was in accordance with the Committee of Sponsoring Organizations of the Treadway Commission (COSO 2013).

The Company's CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal controls over financial reporting at the financial period end of the Company and concluded that such internal controls over financial reporting are effective as of December 31, 2025.

It should be noted that while Bonterra's CEO and CFO believe that the Company's internal controls and procedures provide a reasonable level of assurance and are effective, they do not expect that these controls will prevent all errors and fraud.

Information Regarding Oil and Gas Disclosure

Bonterra's statement of reserves data and other oil and gas information for the year ended December 31, 2025, prepared in accordance with National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), is contained in its Annual Information Form, which is available on the Company's website at www.bonterraenergy.com or on SEDAR+ at www.sedarplus.ca. The recovery and reserve estimates contained herein are estimates only, and there is no assurance that the estimated reserves will be recovered.

Where reserves or future net revenue are disclosed in respect of individual properties or subsets of properties, such estimates may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. Statements regarding the conversion of probable undeveloped reserves into proved reserves constitute forward-looking information and are based on certain assumptions and subject to risks, as described under "Forward-Looking Information."

Bonterra's public filings, including this MD&A, may contain certain oil and natural gas industry metrics, including "reserve life index," "recycle ratio," "reserve replacement," "finding and development costs" ("F&D costs"), "finding and development recycle ratio," "finding, development and acquisition costs" ("FD&A costs"), and "field netbacks." These metrics do not have standardized meanings under IFRS Accounting Standards and may not be comparable to similar measures presented by other issuers. Accordingly, they should not be used to make such comparisons and should not be relied upon in isolation for investment or other purposes.

Management uses these industry metrics to evaluate operating performance, capital efficiency and reserves replacement, and believes they provide readers with additional insight into the Company's performance over time. However, such measures are not reliable indicators of future performance, which may differ materially from performance in prior periods.

F&D and FD&A Costs

F&D costs are calculated as development capital plus the change in estimated future development capital ("FDC") during the period, divided by reserves additions from development activities during the period. Development capital is a non-GAAP financial measure used as a component of F&D costs.

FD&A costs are calculated as development capital plus acquisition capital plus the change in estimated FDC during the period, divided by total reserves additions (excluding production) during the period. Development capital and acquisition capital are non-GAAP financial measures used as components of FD&A costs.

Both F&D and FD&A costs incorporate reserves revisions during the year on a per BOE basis. The aggregate of costs incurred in a particular year and changes during that year in estimated FDC may not reflect total costs associated with reserves additions for that year. F&D and FD&A costs may be presented including or excluding acquisitions and dispositions, as such transactions can significantly impact reserves replacement costs and the comparability of these measures between periods.

Other Industry Metrics

Reserve replacement is calculated as total reserves additions (including acquisitions, net of dispositions) divided by annual production.

Reserve life index represents the theoretical production life of reserves at a given date, calculated by dividing reserves in a specified category by annual production for the period.

Recycle ratio is calculated as field netback per BOE divided by F&D costs per BOE.

Readers are cautioned that the information provided by these industry metrics, or derived from them, should not be relied upon for investment or other purposes and should be considered in conjunction with the Company's audited financial statements and related disclosures.

References in this MD&A and in Bonterra's other public filings to peak rates, initial production rates, test rates and other short-term production rates are useful in confirming the presence of hydrocarbons; however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long-term performance or ultimate recovery. While encouraging, readers are cautioned not to place undue reliance on such rates in calculating the aggregate production of Bonterra. The Company cautions that such results should be considered preliminary.

Use of Non-IFRS Financial Measures

This MD&A contains financial measures and uses the terms “capital expenditures”, “funds flow”, “net debt”, “EBITDA”, “net debt to EBITDA”, “field netback” and “cash netback” which are not prescribed by IFRS as issued by the International Accounting Standards Board (“IFRS Accounting Standards”). These specified financial measures include non-IFRS financial measures and non-IFRS ratios and are not defined by IFRS Accounting Standards, and therefore are referred to as non-IFRS and other financial measures. These non-IFRS and other financial measures are included because management uses the information to analyze business performance, cash flow generated from the business, leverage and liquidity, resulting from the Corporation’s principal business activities and it may be useful to investors on the same basis. None of these measures are used to enhance the Corporation’s reported financial performance or position. The non-IFRS and other measures do not have a standardized meaning prescribed by IFRS Accounting Standards and therefore are unlikely to be comparable to similar measures presented by other issuers. They are common in the reports of other companies but may differ by definition and application in Bonterra’s financial information.

Please see below for a brief overview of non-IFRS measures and the relevant descriptions and reconciliations.

Funds Flow

Funds flow is a non-IFRS financial measure, calculated as cash flow from operating activities including proceeds from sale of investments and investment income received excluding effects of changes in non-cash working capital items and decommissioning expenditures settled. Management uses funds flow to determine the cash generated during a period.

The following is a reconciliation of funds flow to the most directly comparable IFRS measure, cash flow from operating activities:

	Three months ended			Year ended	
($ 000s except $ per share)	**December 31, 2025**	September 30, 2025	December 31, 2024	**December 31, 2025**	December 31, 2024
Cash flow from operations	**21,526**	8,344	28,587	**89,480**	114,952
Adjusted for					
Changes in non-cash working capital	**2,472**	6,066	(2,106)	**3,150**	(5,297)
Interest expense	**(4,231)**	(4,162)	(4,314)	**(16,836)**	(17,821)
Interest paid	**688**	7,705	5,642	**10,930**	17,821
Decommissioning expenditures	**1,608**	3,290	2,245	**7,125**	7,239
Investment income received	**48**	87	46	**319**	326
Proceeds on sale of investments	**-**	-	-	**-**	1,448
Funds Flow	**22,111**	21,330	30,100	**94,168**	118,668
$ per share - basic	**0.61**	0.59	0.81	**2.57**	3.18

Net Debt

Net debt is a non-IFRS financial measure, calculated as long-term subordinated term debt, subordinated debentures and bank debt plus working capital deficiency (current liabilities less current assets). This metric is used by management to analyze the level of debt in the Corporation including the impact of working capital, which varies with the timing of settlement of these balances.

The following is a reconciliation of net debt to the most directly comparable IFRS measures:

($ 000s)	December 31, 2025	December 31, 2024
Bank debt	**40,722**	46,211
Subordinated debentures	**-**	55,872
Subordinated term debt (long-term)	**-**	35,750
Subordinated notes	**135,713**	-
Current liabilities[1]	**43,527**	61,389
Current Assets	**(40,913)**	(32,012)
Net Debt	**179,049**	167,210

[1] Included in current liabilities is $Nil (December 31, 2024 - $19.0 million) of Subordinated Term Debt.

EBITDA

EBITDA is a non-IFRS financial measure. EBITDA is a measure showing net earnings excluding deferred consideration, finance costs, provision for current and deferred taxes, depletion and depreciation, share-based compensation, gain or loss on sale of assets, impairment or impairment reversal, extinguishment of debt and unrealized gain or loss on risk management contracts. Management uses these measures to measure the Corporation's profitability generated by operations.

The following is a reconciliation of trailing twelve-month EBITDA to the most directly comparable IFRS measure, net earnings (loss):

($ 000s)	December 31, 2025	December 31, 2024
Net earnings (loss)	**(17,125)**	10,203
Adjustments to net earnings (loss):		
Unrealized (gain) loss on risk management contracts	**(1,260)**	1,525
Gain on sale of property	**(4,634)**	-
Deferred consideration	**(955)**	(958)
Finance costs	**22,272**	26,532
Share-based compensation	**2,513**	2,293
Depletion and depreciation	**101,594**	97,137
Extinguishment of debt	**11,597**	-
Current income tax expense (recovery)	**(1,691)**	5,167
Deferred income tax recovery	**(2,998)**	(1,513)
EBITDA	**109,313**	140,386
Net debt to EBITDA ratio	**1.6**	1.2

Net Debt to EBITDA

Net debt to EBITDA is a non-IFRS ratio. Net debt to EBITDA is calculated as net debt divided by EBITDA for the trailing twelve months. This measure provides management with an indication of the Corporation's leverage and ability to repay debt.

Capital Expenditures

Capital expenditures are a non-IFRS financial measure. They are calculated as the sum of exploration and evaluation costs and property, plant, and equipment costs per the statement of cash flow. Management uses this metric to assess the total cash capital expenditures incurred during the period.

Field Netback and Cash Netback

Field netback is defined as revenue and realized risk management contract gain (loss) minus royalties and operating expenses divided by total BOEs for the period. Cash netback is defined as field netback less interest expense, general and administrative expense and current income tax expense divided by total BOEs for the period.

Management's Responsibility for Financial Statements

The information provided in this report, including the financial statements, is the responsibility of management. The timely preparation of the financial statements requires that management make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as at the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Management believes such estimates have been based on careful judgments and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Company's assets are safeguarded and to facilitate the preparation of relevant and timely information.

Deloitte LLP has been appointed by the Shareholders to serve as the Company's external auditors. They have examined the financial statements and provided their auditor's report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

"Signed Patrick G. Oliver"

Patrick G. Oliver
Chief Executive Officer
March 12, 2026

"Signed Scott A. Johnston"

Scott A. Johnston
Chief Financial Officer
March 12, 2026.

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of Bonterra Energy Corp.

Opinion

We have audited the financial statements of Bonterra Energy Corp. (the "Company"), which comprise the statements of financial position as at December 31, 2025 and 2024, and the statements comprehensive income, cash flow and changes in equity for the years then ended, and notes to the financial statements, including a summary of significant accounting policies (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2025 and 2024, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

Basis for Opinion

We conducted our audit in accordance with Canadian generally accepted auditing standards ("Canadian GAAS"). Our responsibilities under those standards are further described in the *Auditor's Responsibilities for the Audit of the Financial Statements* section of our report. We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada, and we have fulfilled our other ethical responsibilities in accordance with these requirements. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

Key Audit Matters

Key audit matters are those matters that, in our professional judgment, were of most significance in our audit of the financial statements for the year ended December 31, 2025. These matters were addressed in the context of our audit of the financial statements as a whole, and in forming our opinion thereon, and we do not provide a separate opinion on these matters.

Property, Plant and Equipment - Oil and gas properties - Refer to Notes 4 and 6 to the financial statements

Key Audit Matter Description

The Company's property, plant and equipment includes oil and gas properties. Oil and gas properties are measured by depleting the assets on a unit-of-production basis ("depletion") and are evaluated for impairment and impairment reversal using the future net cash flows of the underlying proved plus probable crude oil and natural gas reserves. The Company engages an independent reserve evaluator to estimate crude oil and natural gas reserves using estimates, assumptions and engineering data. The development of the Company's reserves and the related future net cash flows used to evaluate any impairment or impairment reversal requires management to make significant estimates and assumptions related to crude oil and natural gas prices, discount rates, reserves, and future costs.

Given the significant judgments made by management related to future crude oil and natural gas prices, discount rates, reserves, and future operating and development costs, these estimates and assumptions are subject to a high degree of estimation uncertainty. Auditing these estimates and assumptions required auditor judgement in applying audit procedures and in evaluating the results of those procedures. This resulted in an increased extent of audit effort.

How the Key Audit Matter Was Addressed in the Audit

Our audit procedures related to future crude oil and natural gas prices, discount rates, reserves, and future operating and development costs used to measure oil and gas properties included the following, among others:

- Evaluated future crude oil and natural gas prices by independently developing a reasonable range of forecasts based on reputable third-party forecasts and market data and comparing those to the future crude oil and natural gas prices selected by management.
- Evaluated the reasonableness of the discount rates by testing the source information underlying the determination of the discount rates and developing a range of independent estimates and comparing those to the discount rates selected by management.
- Evaluated the Company’s independent reserve evaluator by examining reports and assessed their scope of work and findings; and assessing the competence, capability and objectivity by evaluating their relevant professional qualifications and experience.
- Evaluated the reasonableness of reserves by testing the source financial information underlying the reserves and comparing the reserve volumes to historical production volumes.
- Evaluated the reasonableness of future operating and development costs by testing the source financial information underlying the estimate, comparing future operating and development costs to historical results, and evaluating whether they are consistent with evidence obtained in other areas of the audit.
- Performed a retrospective review to evaluate management’s ability to accurately forecast and to assess for indications of estimation bias over time.

Other Information

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

- Management’s Discussion and Analysis
- The information, other than the financial statements and our auditor’s report thereon, in the Annual Report.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon. In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit, or otherwise appears to be materially misstated.

We obtained Management’s Discussion and Analysis prior to the date of this auditor’s report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in this auditor’s report. We have nothing to report in this regard.

The Annual Report is expected to be made available to us after the date of the auditor’s report. If, based on the work we will perform on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact to those charged with governance.

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

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company’s ability to continue as a going concern, disclosing, as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company’s financial reporting process.

Auditor’s Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor’s report that includes our opinion. Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian GAAS will always detect a material misstatement when it exists. Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of these financial statements.

As part of an audit in accordance with Canadian GAAS, we exercise professional judgment and maintain professional skepticism throughout the audit. We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.
- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management’s use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company’s ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditor’s report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditor’s report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.

We communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.

We also provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and to communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

From the matters communicated with those charged with governance, we determine those matters that were of most significance in the audit of the financial statements of the current period and are therefore the key audit matters. We describe these matters in our auditor's report unless law or regulation precludes public disclosure about the matter or when, in extremely rare circumstances, we determine that a matter should not be communicated in our report because the adverse consequences of doing so would reasonably be expected to outweigh the public interest benefits of such communication.

The engagement partner on the audit resulting in this independent auditor’s report is Christopher Gill.

“Signed Deloitte LLP”
Chartered Professional Accountants
Calgary, Alberta
March 12, 2025

STATEMENT OF FINANCIAL POSITION

As at ($ 000s)	Note	**December 31, 2025**	December 31, 2024
Assets			
Current			
Accounts receivable		**31,386**	25,778
Crude oil inventory		**840**	885
Prepaid expenses		**6,595**	4,517
Risk management contracts	16	**2,092**	832
		40,913	32,012
Exploration and evaluation assets	5	**9,231**	6,787
Property, plant and equipment	6	**909,290**	936,244
		959,434	975,043
Liabilities			
Current			
Accounts payable and accrued liabilities	7	**37,136**	36,371
Subordinated term debt		**-**	19,000
Decommissioning liabilities	10	**5,548**	5,161
Deferred consideration		**843**	857
		43,527	61,389
Bank debt	8	**40,722**	46,211
Subordinated debentures	9	**-**	55,872
Subordinated term debt	9	**-**	35,750
Subordinated notes	9	**135,713**	-
Deferred consideration		**6,324**	7,265
Decommissioning liabilities	10	**85,271**	98,677
Deferred tax liability	11	**125,845**	129,240
		437,402	434,404
Shareholders' equity			
Share capital	12	**779,371**	783,366
Contributed surplus		**44,751**	36,185
Warrants	12	**-**	6,053
Deficit		**(302,090)**	(284,965)
		522,032	540,639
		959,434	975,043
Commitments and contingencies	17		
Subsequent events	16		

See accompanying notes to these financial statements.

On behalf of the Board:

"Signed Patrick G. Oliver"

Patrick G. Oliver
Director

"Signed Stacey E. McDonald"

Stacey E. McDonald
Director

STATEMENT OF COMPREHENSIVE INCOME (LOSS)

For the years ended December 31 ($ 000s, except $ per share)	Note	2025	2024
Revenue			
Oil and gas sales, net of royalties	13	**216,371**	240,315
Gain on risk management contracts	16	**4,202**	2,044
Deferred consideration		**955**	958
Other income	14	**5,190**	756
		226,718	244,073
Expenses			
Production		**94,500**	89,881
Office and administration		**5,601**	5,262
Employee compensation		**10,455**	9,111
Finance costs	15	**22,272**	26,532
Share-based compensation		**2,513**	2,293
Depletion and depreciation	6	**101,594**	97,137
Extinguishment of debt	9	**11,597**	-
		248,532	230,216
Earnings (loss) before income taxes		**(21,814)**	13,857
Taxes			
Current income tax expense (recovery)	11	**(1,691)**	5,167
Deferred income tax recovery	11	**(2,998)**	(1,513)
		(4,689)	3,654
Net earnings (loss) for the year		**(17,125)**	10,203
Other comprehensive loss			
Unrealized loss on investments		**-**	(186)
Deferred taxes on unrealized loss on investments		**-**	21
Realized gains on available for sale investments transferred to net earnings		**-**	(306)
Deferred taxes on realized gains on available for sale investments transferred to net earnings		**-**	35
Other comprehensive loss for the year		**-**	(436)
Total comprehensive income (loss) for the year		**(17,125)**	9,767
Net earnings (loss) per share - basic	12	**(0.47)**	0.27
Net earnings (loss) per share - diluted	12	**(0.46)**	0.27
Comprehensive income (loss) per share - basic	12	**(0.47)**	0.26
Comprehensive income (loss) per share - diluted	12	**(0.46)**	0.26

See accompanying notes to these financial statements.

STATEMENT OF CASH FLOW

For the years ended December 31 ($ 000s)	Note	**2025**	2024
Operating activities			
Net earnings (loss)		**(17,125)**	10,203
Items not affecting cash			
Deferred income tax recovery	11	**(2,998)**	(1,513)
Share-based compensation		**2,513**	2,293
Investment income		**(319)**	(326)
Finance costs	15	**22,272**	26,532
Extinguishment of debt		**11,597**	-
Unrealized (gain) loss on risk management contracts	16	**(1,260)**	1,525
Deferred consideration		**(955)**	(958)
Depletion and depreciation		**101,594**	97,137
Gain on sale of property		**(4,634)**	(178)
Decommissioning expenditures		**(7,125)**	(7,239)
Interest paid	15	**(10,930)**	(17,821)
Changes in non-cash working capital accounts	15	**(3,150)**	5,297
Cash provided by operating activities		**89,480**	114,952
Financing activities			
Increase (decrease) of bank debt	8	**(5,489)**	31,389
Subordinated debentures	9	**(62,426)**	-
Subordinated term debt	9	**(60,452)**	(19,000)
Subordinated notes, net of issue costs	9	**128,999**	-
Purchase of common shares in trust	12	**(1,725)**	-
Repurchase of common shares	12	**(2,667)**	-
Stock option proceeds		**-**	50
Cash provided by (used in) financing activities		(3,760)	12,439
Investing activities			
Investment income received		**319**	326
Exploration and evaluation expenditures	5	**(2,304)**	(1,190)
Property, plant and equipment expenditures	6	**(67,628)**	(99,886)
Oil and gas property acquisition	6	**(15,288)**	(23,586)
Proceeds on sale of property	6	**2,035**	105
Proceeds on sale of investments		**-**	1,448
Changes in non-cash working capital accounts	15	**(2,854)**	(4,608)
Cash used in investing activities		(85,720)	(127,391)
Net change in cash in the year		**-**	-
Cash, beginning of year		**-**	-
Cash, end of year		**-**	-
The following are included in cash flow from operating activities:			
Income taxes paid		**5,692**	7,007

See accompanying notes to these financial statements.

STATEMENT OF CHANGES IN EQUITY

For the years ended
($ 000's, except number of shares outstanding)

	Numbers of common shares outstanding (Note 12)	Share capital (Note 12)	Contributed surplus [1]	Warrants	Accumulated other comprehensive income (loss)[2]	Deficit	Total shareholders' equity
January 1, 2024	37,253,252	783,185	34,023	6,053	436	(295,439)	528,258
Share-based compensation			2,293				2,293
Exercise of options	71,628	50					50
Transfer to share capital on exercise of options		131	(131)				-
Comprehensive income (loss)					(165)	10,203	10,038
Transfer on realized gain on investments, net of tax					(271)	271	-
December 31, 2024	37,324,880	783,366	36,185	6,053	-	(284,965)	540,639
Share-based compensation			2,513				2,513
Transfer to contributed surplus on expiry of warrants			6,053	(6,053)			-
Purchase of shares in trust, net of tax	(506,300)	(1,328)					(1,328)
Repurchase of common shares	(749,900)	(2,667)					(2,667)
Comprehensive loss					-	(17,125)	(17,125)
December 31, 2025	36,068,680	779,371	44,751	-	-	(302,090)	522,032

[1] All amounts reported in Contributed Surplus relate to share-based compensation.

[2] Accumulated other comprehensive income is comprised of unrealized gains and losses on investments fair value through other comprehensive income.

See accompanying notes to these financial statements.

NOTES TO THE FINANCIAL STATEMENTS

As at and for the years ended December 31, 2025 and December 31, 2024.

1. NATURE OF BUSINESS AND SEGMENT INFORMATION

Bonterra Energy Corp. ("Bonterra" or the "Company") is a public company listed on the Toronto Stock Exchange (the "TSX") and incorporated under the Business Corporations Act (Alberta). The address of the Company's registered office is Suite 800, 215-9th Avenue SW, Calgary, Alberta, Canada, T2P 1K3. The common shares of the Company (the "Common Shares") are listed for trading on the TSX under the symbol "BNE".

Bonterra operates in one industry and has only one reportable segment which is the development and production of oil and natural gas in the Western Canadian Sedimentary Basin.

2. BASIS OF PREPARATION AND FUTURE OPERATIONS

a) Statement of Compliance

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

The financial statements were authorized for issue by the Company's Board of Directors on March 12, 2025.

b) Basis of Measurement

These financial statements have been prepared on a historical cost basis, except for certain financial instruments and share-based payment transactions which are measured at fair value.

c) Functional and Presentation Currency

The Company's functional and presentation currency is the Canadian dollar.

Foreign currency denominated monetary assets and liabilities are translated into Canadian dollars at the rates prevailing on the reporting date. Non-monetary assets and liabilities are translated into Canadian dollars at the rates prevailing on the transaction dates. Exchange gains and losses are recorded as income or expense in the period in which they occur.

d) Material Accounting Estimates and Judgments

The timely preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the statement of financial position as well as the reported amounts of revenues, expenses and cash flows during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the financial statements. Actual results could differ materially from estimated amounts. See Note 4 for more information.

e) Future Accounting Pronouncements

Amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures

In May 2024, the IASB issued amendments to IFRS 9 Financial Instruments and IFRS 7 Financial Instruments: Disclosures relating to settling financial liabilities using an electronic payment system and assessing contractual cash flow characteristics of financial assets. The amendments are effective on January 1, 2026, but will not have a material impact on Bonterra's financial statements.

IFRS 18 – Presentation and Disclosure in Financial Statements

On April 9, 2024 the IASB issued IFRS 18, "Presentation and Disclosure in Financial Statements" ("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 Comprehensive Income (Loss) and improve comparability across entities and reporting periods. IFRS 18 is effective for annual periods beginning on or after January 1, 2027, with early adoption permitted. The standard is to be applied retrospectively, with certain transition provisions. The Company is currently evaluating the impact of adopting IFRS 18 on its financial statements.

3. MATERIAL ACCOUNTING POLICIES

a) Revenue Recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is measured based on the consideration specified in contracts with customers. Revenue from contracts with customers is recognized when or as Bonterra satisfies a performance obligation by transferring a promised good or service to a customer. A good or service is transferred when the customer obtains control of that good or service. The transfer of control of oil, natural gas, and natural gas liquids usually coincides with title passing to the customer and the customer taking physical possession. The Company principally satisfies its performance obligations at a point in time and the amounts of revenue recognized relating to performance obligations satisfied over time are not significant. Collection of revenue associated with the sale of crude oil, natural gas and natural gas liquids occurs on or about the 25th of the month following production. Items such as royalties for Crown, freehold, gross overriding (GORR) and Saskatchewan surcharge are netted against revenue. These items are netted to reflect the deduction for other parties' proportionate share of the revenue. Administration fee income is recorded when services are provided.

b) Joint Arrangements

Certain exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Company's interests in such activities. A jointly controlled operation involves the use of assets and other resources of the Company and those of other joint venture participants through contractual arrangements rather than through the establishment of a corporation, partnership or other entity. The Company has no interests in jointly controlled entities. The Company recognizes in its financial statements its interest in assets that it owns, the liabilities and expenses that it incurs, and its share of income earned by the joint arrangement.

c) Inventories

Inventories consist of crude oil. Crude oil stored in the Company's tanks is valued on a first-in, first-out basis at the lower of cost or net realizable value. The inventory cost for crude oil is determined based on the combined average per barrel operating costs, and depletion and depreciation for the period, while net realizable value is determined based on estimated sales price less transportation costs.

d) Exploration and Evaluation Assets

General exploration and evaluation ("E&E") expenditures incurred prior to acquiring the legal right to explore are charged to expense as incurred.

E&E expenditures represent undeveloped land costs, licenses and exploration well costs.

Undeveloped land costs, licenses and exploration well costs are initially capitalized and, if subsequently determined to have not found sufficient reserves to justify commercial production, are charged to expense. E&E assets continue to be capitalized as long as sufficient progress is being made to assess the reserves and economic viability of the asset. Once technical feasibility and commercial viability has been established, E&E assets are transferred to property, plant and equipment ("PP&E"). E&E assets are assessed for impairment annually, upon transfer to PP&E assets or whenever indications of impairment exist to ensure they are not at amounts above their recoverable amounts.

e) Property, Plant and Equipment

PP&E assets include transferred-in E&E costs, development drilling and other subsurface expenditures. PP&E assets are carried at cost less depletion and depreciation of all development expenditures and include all other expenditures associated with PP&E assets.

Oil and Gas Properties

The initial cost of an asset is comprised of its purchase price or construction cost, including expenditures such as drilling costs; the present value of the initial and changes in the estimate of any decommissioning obligation associated with the asset; and finance charges on qualifying assets that are directly attributable to bringing the asset into operation and to its present location.

Production Facilities

Production facilities are comprised of costs related to petroleum and natural gas plant and production equipment.

Leases

Leases or contractual obligations are capitalized as right of use assets ("ROUs") with a corresponding right of use lease obligation using the present value of future lease payments on the statement of financial position. The discount rate used to determine the ROU is the stated rate in the lease contract. If no discount rate is provided, the Company's incremental borrowing rate is used. Certain lease payments will continue to be expensed in the statement of comprehensive income. These leases are contractual obligations that contain any of the following: are equal to or less than twelve months; are for oil and gas extraction; are variable payments; the Company does not control the asset; or no asset is identified in the lease.

Depletion and Depreciation

Depletion and depreciation is recognized in the statement of comprehensive income (loss).

PP&E properties, excluding surface costs are depleted using the unit-of-production method over their proved plus probable developed reserve life, when commercial production in an area has commenced. Proved plus probable developed reserves are determined annually by qualified independent reserve engineers. Changes in factors such as estimates of proved plus probable developed reserves that affect unit-of-production calculations are accounted for on a prospective basis. Surface costs such as production facilities and furniture, fixtures and other equipment are depreciated over their estimated useful lives.

Production facilities, furniture, fixtures and other equipment are depreciated over the individual assets estimated economic lives, less estimated salvage value of the assets at the end of their useful lives.

These assets are depreciated as follows:

Production facilities	Declining balance method at 10 percent per year

Furniture, fixtures and other equipment	Declining balance method at 10 to 20 percent per year
Right of use assets	Straight line method over the term of the associated lease

Effective January 1, 2026, the estimated useful life of PP&E properties (including surface costs) was revised to the unit-of-production method based on proved plus probable reserves. The calculation incorporates estimated future development costs required to bring reserves into production and estimated salvage values. Reserve estimates are determined annually by qualified independent reserve engineers.

This change represents a change in accounting estimates under IAS 8 and has been applied prospectively in accordance with IFRS.

f) Impairment of Assets

Impairment of Financial Assets

A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flow of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flow discounted at the original effective interest rate. Significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics.

All impairment losses are recognized in net earnings. An impairment loss is reversed if there is an indicator that the impairment reversal can be related objectively to an event occurring after the impairment loss was recognized. Any subsequent recovery of an impairment loss in respect of an investment in an equity instrument classified as fair value through other comprehensive income (“FVTOCI”) is reversed through other comprehensive income instead of net earnings. For financial assets measured at amortized cost, the reversal is recognized in net earnings.

Impairment of Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at the end of each reporting period to determine whether there is any indication of impairment. If such indication exists, then the assets’ carrying amounts are assessed for impairment.

For the purpose of impairment testing, assets (which include E&E, PP&E and goodwill) are grouped together into the smallest group of assets that generate cash flows from continuing use which are largely independent of the cash flow of other assets or groups of assets (the cash-generating unit or “CGU”). Goodwill is allocated to the CGU expected to benefit from the synergies of the combination. The recoverable amount of an asset or a CGU is the greater of its value-in-use (“VIU”) and its fair value less costs to sell (“FVLCS”). The Company has a core CGU composed of its Alberta properties and secondary CGUs for its British Columbia (BC) and Saskatchewan properties.

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its recoverable amount. Impairment losses are recognized in the statement of comprehensive income (loss). Impairment losses recognized in respect of a CGU are allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amount of the other assets of the CGU on a pro-rata basis.

In respect of assets other than goodwill, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the impairment loss has reversed. If the amount of the impairment loss reverses in a subsequent period and the reversal can be objectively related to an event occurring after the impairment was recognized, the impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized and recorded in the statement of comprehensive income (loss). An impairment loss in respect of goodwill cannot be reversed.

g) Deferred Consideration

Deferred consideration is generated when a sale of a royalty interest linked to production at a specific property occurs. Consideration is given to the specific terms of each arrangement to determine whether a disposal of an interest in the reserves of the respective property has occurred and whether the counterparty is entitled to the associated risks and rewards attributable to the property over its estimated life. These include the contractual terms and implicit obligations related to production, such as the holder of the royalty having the option of either being paid in cash or in kind and the associated commitments, if any, to develop future expansions or projects at the property.

Proceeds for sale of a royalty interest on petroleum properties are then attributed to two components: a payment for partial disposal of an interest in PP&E; and an upfront payment received for future extraction services that will generate future royalties. Discounted future cash flows of future development and operating costs multiplied by the royalty rate are used to derive the upfront payment received for future extraction services, which is accounted for as deferred consideration and recognized as revenue over the reserve life of the encumbered properties (as this represents the efforts incurred towards the extraction performance obligation). Upon commencement of the royalty interest the deferred consideration is depleted (recognized into revenue) using the same unit-of-production method as the depletion of the encumbered PP&E asset's carrying value.

h) Decommissioning Liabilities

The fair value of the statutory, contractual, constructive or legal liabilities associated with the retirement and reclamation of oil and gas properties is recorded when incurred, with a corresponding increase to the carrying amount of the related PP&E. The amount recognized is the estimated cost of decommissioning, discounted to its present value using the Company's risk-free rate. Changes in the estimated timing of decommissioning or decommissioning cost estimates and changes to the risk-free rates are dealt with prospectively by recording an adjustment to the decommissioning liabilities, and a corresponding adjustment to PP&E. The unwinding of the discount on the decommissioning provision is charged to net earnings as a finance cost.

The Company recognizes a decommissioning liability in the period in which it is incurred when a reasonable estimate of the liability can be made. On a periodic basis, management will review these estimates and changes and if there are any, they will be applied prospectively. The fair value of the estimated provision is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the proved plus probable developed reserves. The liability amount is increased each reporting period due to the passage of time and this amount is charged to earnings in the period. Actual costs incurred upon settlement of the obligations are charged against the provision to the extent of the liability recorded and any remaining balance of actual costs is recorded in the statement of comprehensive income (loss).

i) Income Taxes

Tax expense comprises current and deferred taxes. Tax is recognized in the statement of comprehensive income (loss) or directly in equity.

Current tax expense is based on the results for the period as adjusted for items that are not taxable or not deductible. Current tax is calculated using tax rates and laws that are substantively enacted at the end of the reporting period. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. Provisions are established where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred tax is recognized using the liability method, providing for unused tax losses, unused tax credits and temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for the following temporary differences: the initial recognition of assets and liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit, and differences relating to investments in subsidiaries to the extent that they are unlikely to be reversed in the foreseeable future. Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which unused tax losses, unused tax credits and temporary differences can be utilized. Deferred tax assets are reviewed at each period end and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

The amount and timing of reversals of temporary differences will also depend on the Company's future operating results, and acquisitions and dispositions of assets and liabilities. A significant change in any of the preceding assumptions could materially affect the Company's estimate of the deferred income tax asset or liability.

j) Share-Based Compensation

The Company accounts for equity-settled share-based compensation using the fair value method. Stock options granted to directors, officers, employees, and other service providers are measured at grant-date fair value using the Black-Scholes option pricing model. Compensation expense is recognized in the statement of comprehensive income (loss) over the vesting period, with a corresponding increase to contributed surplus. Awards with graded vesting are accounted for as separate tranches and expensed over their respective vesting periods.

At each reporting date, the Company estimates the number of awards expected to vest and recognizes the impact of changes in estimates prospectively.

Upon exercise of stock options, cash proceeds received, net of transaction costs, together with amounts previously recorded in contributed surplus, are credited to share capital.

Employees may elect to have the Company settle any or all options vested and exercisable using a cashless equity settlement. In connection with any such exercise, an employee shall be entitled to receive, without any cash payment (other than the taxes required to be paid in connection with the exercise), whole common shares of the Company. The number of common shares issued is determined by multiplying the number of options exercised by the excess of the fair value of the common shares at the time of exercise over the option exercise price, divided by the fair value of the common shares at the time of exercise.

The Company grants restricted share units ("RSUs") to employees and deferred share units ("DSUs") to non-employee directors. RSUs and DSUs are equity-settled and settled in common shares. Shares required for settlement are purchased in the open market by an independent trustee.

The grant-date fair value of RSUs and DSUs is recognized as compensation expense over the vesting period, with a corresponding increase to contributed surplus. Upon vesting of RSUs, amounts are reclassified from contributed surplus to share capital. DSUs vest over the director's service period and are settled upon retirement from the Company.

k) Financial Instruments

The Company classifies its financial instruments into one of the following categories: financial assets at amortized cost, financial liabilities at amortized costs; and fair value through profit or loss. All financial instruments are measured at fair value on initial recognition. Measurement in subsequent periods is dependent on the classification of the respective financial instrument.

Fair value through profit or loss financial instruments are subsequently measured at fair value with changes in fair value recognized in net earnings. All other categories of financial instruments are measured at amortized cost using the effective interest rate method.

Cash, account receivables and certain other long-term assets are classified as financial assets at amortized cost since it is the Company's intention to hold these assets to maturity and the related cash flows are mainly payments of principle and interest.

Accounts payable, accrued liabilities, and certain other long-term liabilities and long-term debt are classified as financial liabilities at amortized cost.

During the year, the Company extinguished its existing subordinated term debt and subordinated debentures and replaced them with subordinated notes. In accordance with IFRS 9, the extinguishment was accounted for as a derecognition of the original financial liabilities, as the terms of the new debt were substantially different from those of the extinguished instruments. The original liabilities were derecognized, and the subordinate notes were recognized at fair value on the date of issuance. The resulting gain or loss on extinguishment, representing the difference between the carrying amount of the extinguished liabilities and the fair value of the new debt issued, was recognized in profit or loss. Transaction costs directly attributable to the issuance of the subordinated notes were deducted from the carrying amount of the new liability and amortized over its term using the effective interest method.

Risk management assets and liabilities are classified as fair value through profit or loss.

l) Fair Value Measurement

Financial instruments consisting of accounts receivable, accounts payable and accrued liabilities, due to related party, subordinated promissory note, subordinated term debt and bank debt on the statement of financial position are carried at amortized cost. Investments are carried at fair value. All of the investments are transacted in active markets. Bonterra determines the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Bonterra's investments have been assessed on the fair value hierarchy described above and are all considered Level 1.

m) Risk Management Contracts

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign currency exchange rates and interest rates in the normal course of its business. The Company may use a variety of instruments to manage these exposures. For transactions where hedge accounting is not applied, the Company accounts for such instruments using the fair value method by initially recording an asset or liability and recognizing changes in the fair value of the instruments in earnings as unrealized gains or losses on risk management contracts. Fair values of financial instruments are based on third party quotes or valuations provided by independent third parties. Any realized gains or losses on risk management contracts are recognized in net earnings in the period they occur. Bonterra's risk management contracts have been assessed on the fair value hierarchy described above and are all considered Level 2.

n) Net Earnings and Comprehensive Income Per Share

Per share amounts are calculated by dividing the net earnings or comprehensive income (loss) attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the reporting period.

Diluted per share amounts are calculated similar to basic per share amounts except that the weighted average common shares outstanding are increased to include additional common shares from the assumed exercise of dilutive share-options. The number of additional outstanding common shares is calculated by assuming that the outstanding in-the-money share-options were exercised and that the proceeds from such exercises were used to acquire common shares at the average market price during the reporting period.

4. SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected. The following are the estimates and judgments applied by management that most significantly affect the Company's financial statements.

Exploration and Evaluation Expenditures

E&E costs are initially capitalized with the intent to establish commercially viable reserves. E&E assets include undeveloped land and costs related to exploratory wells. The Company is required to make estimates and judgments about future events and circumstances regarding the future economic viability of extracting the underlying resources. Changes to project economics, resource quantities, expected production techniques, unsuccessful drilling, expired mineral leases, production costs and required capital expenditures are important factors when making this determination. To the extent a judgment is made that the underlying reserves are not viable, the E&E costs will be impaired and charged to net earnings.

Impairment of Non-Financial Assets

PP&E and goodwill are aggregated into CGUs based on their ability to generate largely independent cash flows and are assessed for impairment or in the case of PP&E impairment reversals. CGUs have been determined based on similar geological structure, shared infrastructure, geographical proximity, commodity type, and similar market risks. Oil and gas prices and other assumptions will change in the future, which may impact the Company's recoverable amounts and may therefore require a material adjustment to the carrying value of PP&E. The determination of the Company's CGUs is subject to management's judgment. The Company has a core CGU composed of its Alberta properties and secondary CGUs for its BC and Saskatchewan properties.

The recoverable amount of E&E and PP&E, is determined based on the fair value less costs of disposal using a discounted cash flow model and is assessed at the CGU level. The period the Company used to project cash flows is approximately 50 years or the CGUs reserve life. Growth in cash flow from a single well would be determined based on the extent of total reserves assigned, which is produced at declining rates over the estimated reserve life. The fair value measurement of the Company's E&E and PP&E, is designated Level 3 on the fair value hierarchy.

The Company performs an impairment test on all of its CGUs for any potential impairment or related recovery at least annually or when impairment or recovery indicators arise. In making these evaluations, the Company uses the following information:

1) The net present value of the pre-tax cash flows from oil and gas reserves of each CGU based on total proved plus probable reserves estimated by the Company's independent reserve evaluator; and

2) Key input estimates used in the determination of cash flows from oil and gas reserves include the following:

    a) Reserves - Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, production costs or recovery rates may change the economic status of reserves and may ultimately result in reserves being revised.

    b) Crude oil and natural gas prices - Forward price estimates of the crude oil and natural gas prices are used in the discounted cash flow model. These prices are adjusted for quality differentials, heat content and distance to market. Commodity prices have fluctuated widely in recent years due to global and regional factors including supply and demand fundamentals, inventory levels, exchange rates, weather, economic and geopolitical factors.

    c) Discount rate - The Company uses a pre-tax discount rate of fifteen percent that reflects risks specific to the assets for which the future cash flow estimates have not been adjusted. The discount rate was determined based on the Company's assessment of risk based on past experience. Changes in the general economic environment could result in material changes to this estimate.

No indicators of impairment or impairment reversal were identified as at December 31, 2025.

Reserves Estimation

The capitalized costs of oil and gas properties and deferred consideration are depleted on a unit-of-production basis at a rate calculated by reference to proved plus probable developed reserves determined in accordance with National Instrument 51-101 and the Canadian Oil and Gas Evaluation handbook. Commercial reserves are determined using best estimates of oil and gas in place, recovery factors and future oil and gas prices. Amounts used for impairment calculations are also based on estimates of crude oil and natural gas reserves and future costs required to develop those reserves.

Risk Management Contract

The Company accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in net earnings as unrealized gains or losses on risk management contracts. Fair values of financial instruments are based on third party futures quotes for commodities. Any realized or unrealized gains or losses on risk management contracts are recognized in net earnings in the period they occur.

Share-option Compensation

The Company measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date they are granted. Estimating the fair value requires the determination of the most appropriate valuation model for a grant, which is dependent on the terms and conditions of the grant. This also requires the determination of the most appropriate inputs to the valuation model including the expected life of the option, risk-free interest rates, volatility and dividend yield.

Share-based Compensation

The Company measures the cost of equity-settled share-based compensation by reference to the fair value of the equity instruments at the date they are granted. Estimating the fair value of share options requires judgment in the selection of an appropriate valuation model and the determination of key assumptions, including expected life, risk-free interest rates, volatility and dividend yield. The fair value of restricted share units ("RSUs") and deferred share units ("DSUs") is based on the market price of the Company's common shares at the grant date and requires judgment in estimating forfeiture rates and the number of awards expected to vest.

Deferred Consideration

Deferred consideration is incurred when the sale of a royalty interest occurs that has contractual terms or implicit obligations that requires future performance such future development costs and operating costs. Management uses judgments in determining those cash flows such as cost, inflation and the discount rate to determine the portion of proceeds that is deferred.

Decommissioning and Restoration Costs

Decommissioning and restoration costs will be incurred by the Company at the end of the operating lives of the Company's oil and gas properties. Provisions for decommissioning liabilities are based on cost estimates which can vary in response to many factors including timing of abandonment, inflation, changes in legal requirements, new restoration techniques and interest rates.

Income Taxes

The Company recognizes the net deferred tax benefit or expense related to deferred income tax assets or liabilities to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of investment tax credit receivable requires the Company to make significant estimates related to expectations of future taxable income. The provision for income taxes is based on judgments in applying income tax law and estimates of the timing, likelihood and reversal of temporary differences between the accounting and tax basis of assets and liabilities. The ability to realize on the deferred tax assets and investment tax credit receivable recorded on the balance sheet may be compromised to the extent that any interpretation of tax law is challenged, or taxable income differs significantly from estimates.

Further details regarding accounting estimates and judgments are disclosed in Note 3.

5. EXPLORATION AND EVALUATION ASSETS

($ 000s)	
Cost and carrying amount	
Balance at January 1, 2024	5,785
Additions	1,190
Balance at December 31, 2024	6,787
Additions	2,444
Balance at December 31, 2025	**9,231**

6. PROPERTY, PLANT AND EQUIPMENT

Cost ($ 000s)	Oil and gas properties	Production facilities	Furniture fixtures & other equipment	Total property plant & equipment
Balance at January 1, 2024	1,655,513	446,131	2,811	2,104,455
Additions	62,417	37,368	101	99,886
Acquisition	19,354	4,880	-	24,234
Adjustment to decommissioning liabilities	(15,586)	-	-	(15,586)
Disposal	-	(282)	-	(282)
Balance at December 31, 2024	1,721,698	488,097	2,912	2,212,707
Additions	40,329	26,655	644	67,628
Acquisition	12,889	3,140	-	16,029
Adjustment to decommissioning liabilities	(7,650)	-	-	(7,650)
Disposal	(13,160)	(4,246)	-	(17,406)
Balance at December 31, 2025	**1,754,106**	**513,646**	**3,556**	**2,271,308**

Accumulated depletion and depreciation ($ 000s)	Oil and gas properties	Production facilities	Furniture fixtures & other equipment	Total property plant & equipment
Balance at January 1, 2024	(962,387)	(215,046)	(2,097)	(1,179,530)
Depletion and depreciation	(77,485)	(19,534)	(118)	(97,137)
Disposal and other	2	202	-	204
Balance at December 31, 2024	(1,039,870)	(234,378)	(2,215)	(1,276,463)
Depletion and depreciation	(81,005)	(20,373)	(216)	(101,594)
Disposal and other	12,275	3,764	-	16,039
Balance at December 31, 2025	**(1,108,600)**	**(250,987)**	**(2,431)**	**(1,362,018)**
Carrying amounts as at: ($ 000s)				
December 31, 2024	681,828	253,719	697	936,244
December 31, 2025	**645,506**	**262,659**	**1,125**	**909,290**

Asset Acquisition of Oil and Natural Gas properties

On December 18, 2025, the Company acquired additional assets in the Charlie Lake area for cash considerations of $15.3 million in mineral rights, including closing adjustments ("Bonanza Asset Acquisition"). This acquisition has been accounted for as an asset acquisition, which resulted in a $16.0 million increase in PP&E and the assumption of $ 0.7 million in decommissioning liabilities.

Asset Disposition of Oil and Natural Gas properties

The Company disposed of certain non-core oil and gas assets primarily located in Saskatchewan for total consideration of $2.2 million, including closing adjustments. The consideration consisted of $2.1 million in cash and $0.1 million in non-core mineral rights.

The transaction resulted in a gain on sale of property of $4.6 million, which has been recognized in the statement of comprehensive loss for the period. As part of the disposition, decommissioning liabilities of approximately $3.8 million associated with the assets were also derecognized.

Impairment

There were no indicators of impairment losses or reversals identified as at December 31, 2025 and 2024.

7. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

($ 000s)	**December 31, 2025**	December 31, 2024
Accounts payable	**23,685**	24,294
Accrued liabilities	**13,451**	12,077
	37,136	36,371

8. BANK DEBT

As at December 31, 2025 the Company had a total Bank Facility of $150,000,000 (December 31, 2024 - $110,000,000), comprised of a $125,000,000 syndicated revolving credit facility, and a $25,000,000 non-syndicated revolving credit facility. The amount drawn under the total Bank Facility as at December 31, 2025 was $40,722,000 (December 31, 2024 - $46,211,000). The amounts borrowed under the total Bank Facility bear interest at a floating rate based on the applicable Canadian prime rate or CORRA rate, plus between 2.00 percent and 6.25 percent, depending on the type of borrowing. As at December 31, 2025, the terms of the total revolving Bank Facility provided that the loan facility was revolving to April 30, 2026, with a maturity date of April 30, 2027, with no set terms of repayment on the credit facility.

The amount available for borrowing under the Bank Facility is reduced by outstanding letters of credit. Letters of credit totaling $2,150,000 were issued as at December 31, 2025 (December 31, 2024 - $1,990,000). Security for the Bank Facility consists of various floating demand debentures totaling $750,000,000 (December 31, 2024 - $750,000,000) over all of the Company's assets and a general security agreement with first ranking over all personal and real property.

9. SUBORDINATED NOTES

As at December 31, 2025, the Company has 135,000 Senior Secured Second Lien Notes (the "Notes") outstanding. Each unit consists of one Note with a par value of $1,000, bearing interest at a fixed annual rate of 10.5%, payable semi-annually on January 28 and July 28, commencing July 28, 2025. The Notes mature on January 28, 2030.

The Notes are non-callable by the Corporation prior to January 28, 2028. On or after January 28, 2028, the Corporation may redeem all or part of the Notes at the redemption prices set forth below, plus any accrued and unpaid interest, for the twelve-month period beginning on:

I. January 28, 2028: 102.625%
II. January 28, 2029 and thereafter: 100.000%

The Notes were issued at a discount, with an issue price of $981.16 per $1,000 of principal, resulting in gross proceeds of $131.5 million and initial issue costs of $3.5 million. The effective interest rate, determined using the effective interest rate method and reflecting both the discount and transaction costs, was 11.4%. The carrying amount of the Notes will accrete to the principal amount over the life of the Notes. For 2025, interest expense recognized was $12.9 million (December 31, 2024 – $Nil).

The Notes are secured by a second lien charge over all personal and real property of the Company, ranking behind the Company's first lien credit facilities.

Extinguishment of Subordinated Debt
As part of a capital restructuring completed during Q1 2025, the Company fully repaid two classes of subordinated debt:

(a) Subordinated Term Debt

On January 28, 2025, the Company extinguished its subordinated term debt with the following payments:
- Principal repayment of $57.0 million
- Accrued and unpaid interest of $0.5 million
- Early redemption fee of $3.4 million (recognized in loss on extinguishment of debt)
- Acceleration of unamortized issue costs of $2.1 million (recognized in loss on extinguishment of debt)

(b) Subordinated Debentures

On February 26, 2025, the Company repaid in full its outstanding subordinated debentures:
- Principal repayment of $59.0 million
- Accrued and unpaid interest of $0.8 million
- Early redemption fee of $3.5 million (recognized in loss on extinguishment of debt)
- Acceleration of unamortized issue costs of $2.6 million (recognized in loss on extinguishment of debt)

The following table presents the total extinguishment of debt costs:

($000s)	2025
Cash extinguishment of debt	6,877
Accretion extinguishment of debt	4,720
Total extinguishment of debt	11,597

10. DECOMMISSIONING LIABILITIES

At December 31, 2025, the estimated total uninflated and undiscounted amount required to settle the decommissioning liabilities was $193,264,000 (December 31, 2024- $179,396,000). The provision has been calculated assuming a 2.0 percent inflation rate (December 31, 2024 – 2.0 percent inflation rate). These obligations will be settled at the end of the useful lives of the underlying assets, which extend up to 50 years into the future. This amount has been discounted using a risk-free interest rate of 4.28 percent (December 31, 2024 – 3.45 percent).

The estimated decommissioning liabilities are sensitive to changes in key assumptions. Changing the discount rate by 0.1%, with all other assumptions held constant, would result in a corresponding decrease or increase of the decommissioning liability by approximately $2.6 million. Similarly, reducing the estimated settlement timing of the obligations by one year would result in an increase in the decommissioning liability of $4.0 million.

($ 000s)	**December 31, 2025**	December 31, 2024
Decommissioning liabilities, January 1	**103,838**	123,108
Changes in estimate[1]	**(7,650)**	(15,279)
Liabilities settled during the year[2]	**(9,339)**	(7,683)
Accretion on decommissioning liabilities	**3,970**	3,692
Total decommissioning liabilities, end of year	**90,819**	103,838
Current portion of decommissioning liabilities	**(5,548)**	(5,161)
Decommissioning liabilities	**85,271**	98,677

[1] The change is estimate was primarily due to an increase in estimated costs less a decrease in the discount rate.
[2] Included in liabilities settled is a recovery of $868,000 in abandonment deposits (December 31, 2024 - $444,000 expenditure).

11. INCOME TAXES

($ 000s)	**December 31, 2025**	December 31, 2024
Deferred tax asset (liability) related to:		
Exploration and evaluation assets and property, plant and equipment	**(143,033)**	(149,093)
Decommissioning liabilities	**21,358**	24,565
Share issue costs	**1,501**	715
Financial derivative	**(481)**	(192)
Subordinated debenture	**-**	(720)
Subordinated term debt	**-**	(518)
Subordinated notes	**(1,195)**	-
Corporate capital tax losses carried forward	**7,377**	7,377
Unrecorded benefits of capital tax losses carried forward	**(7,377)**	(7,377)
Unrecorded benefits of successored resource related pools	**(3,995)**	(3,997)
Deferred tax liability	**(125,845)**	(129,240)

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial tax rates as follows:

($ 000s)	**December 31, 2025**	December 31, 2024
Earnings before taxes	**(21,814)**	13,857
Combined federal and provincial income tax rates	**23.00%**	23.01%
Income tax provision calculated using statutory tax rates	**(5,018)**	3,189
Increase (decrease) in taxes resulting from:		
Share-based compensation	**578**	528
Shares purchased in trust	**(397)**	-
Change in unrecorded benefits of tax pools	**(2)**	(9)
Change in estimates and other	**150**	(54)
	(4,689)	3,654

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

($ 000s)	Rate of Utilization (%)	Amount
Undepreciated capital costs	7-100	87,491
Share issue and financing costs	20	4,801
Canadian oil and gas property expenditures	10	77,222
Canadian development expenditures	30	114,582
Canadian exploration expenditures	100	8,587
		292,683

The Company has $64,111,000 (December 31, 2024 - $64,111,000) of capital losses carried forward which can only be claimed against taxable capital gains.

At December 31, 2025, the Company expects to receive an income tax refund of approximately $8.0 million, primarily related to installment payments made during 2025, which is included in accounts receivable.

12. SHAREHOLDERS' EQUITY

Authorized

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

	December 31, 2025		December 31, 2024	
Issued and fully paid - common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**37,324,880**	**783,366**	37,253,252	783,185
Issued pursuant to the Company's share option plan	**-**	**-**	71,628	50
Transfer from contributed surplus to share capital		**-**		131
Purchase of common shares in trust, net of tax	**(506,300)**	**(1,328)**	-	-
Repurchase of common shares	**(749,900)**	**(2,667)**	-	-
Balance, end of year	**36,068,680**	**779,371**	37,324,880	783,366

The Company is authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable Preferred Shares or Class "B" Preferred Shares.

On April 11,2025, the Company announced that the Toronto Stock Exchange had accepted the notice of the Company to implement a Normal Course Issuer Bid (NCIB). Pursuant to the NCIB the Company is permitted to repurchase up to 3,199,449 common shares, representing approximately 10 percent of its public float between April 15, 2025, and April 14, 2026. During 2025 (December 31, 2024 – nil) the Company purchased 749,900 common shares for cancellation at an average price of $3.56 per common share.

The weighted average common shares used to calculate basic and diluted net earnings per share for the year ended, are as follows:

	2025	2024
Basic shares outstanding	**36,615,217**	37,302,410
Dilutive effect of share options, share awards and warrants[1]	**242,670**	22,854
Diluted shares outstanding	**36,857,887**	37,325,264

(1) The Company did not include 2,402,000 share-options, RSUs and DSUs (or share awards) and warrants (December 31, 2024 – 5,720,000) in the dilutive effect of share-options, share awards and warrants calculations as these were anti-dilutive.

Warrants

The Company had 2,753,000 Warrants outstanding as of December 31, 2024. Each Warrant entitled the holder to purchase one common share of the Company at an exercise price of $7.75. All such Warrants expired unexercised on October 20, 2025, and no Warrants were outstanding as of December 31, 2025.

Restricted and Deferred Share Units

The Company provides an equity settled stock incentive plan which authorized the Board to grant restricted share units (RSU) and Deferred share units (DSU) to directors, officers and employees of Bonterra. Each RSU entitles the holder to common shares of the Company to be paid on each of the first, second and third anniversaries from the date of Grant.

The Company has a DSU plan pursuant to which it may make an annual grant of DSUs to non-employee directors. Pursuant to the DSU plan, DSUs are awarded as part of annual grant vest quarterly from the date of grant. However, the DSU will not be released until the non-employee director has ceased to be a member of the board of directors of the Company. The award value is calculated at the payment date by multiplying the number of DSUs by the fair market value of the common shares of the Company.

RSUs and DSUs are settled at the Company's option in cash and/or common shares acquired by the Company on the stock exchange. The Company's intention is to settle the RSU/DSU plans in common shares and it has therefore accounted for the RSU/DSU awards as equity-settled.

During 2025 (December 31, 2024 – nil), the Company purchased 506,300 common shares at an average price of $3.40 per share to be held in trust for future RSU and DSU settlements.

	Number of restricted share units	**Number of deferred share units**
Balance at December 31, 2024	-	-
Granted	955,000	102,500
Balance at December 31, 2025	955,000	102,500

Options

The Company provides an equity settled option plan for its directors, officers, and employees. Under the plan, the Company may grant options for up to 3,657,498 (December 31, 2024 – 3,732,488 common shares). The exercise price of each option granted cannot be lower than the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock options as of December 31, 2025 and changes during the year are presented below:

	Number of options	**Weighted average exercise price**
At January 1, 2024	3,260,000	$6.87
Options granted	147,000	4.81
Options exercised[1]	(118,500)	2.67
Options forfeited	(145,500)	7.21
Options expired	(37,500)	8.13
At December 31, 2024	3,105,500	$6.90
Options granted	425,000	3.86
Options forfeited	(1,715,500)	7.87
Options expired	(82,500)	5.92
At December 31, 2025	1,732,500	$5.24

(1) Nil options (December 31, 2024 – 108,500) were exercised under the cashless option method, which resulted in nil (December 31, 2024 -61,628) shares being issued in which the Company received no proceeds. Under the cashless option method, the remaining options between the number of options exercised and shares issued are cancelled.

During 2025, 1,715,500 options were forfeited or expired prior to their original expiry dates, primarily due to employee departures and revisions to the Company's long-term incentive structure.

The following table summarizes information about options outstanding and exercisable as at December 31, 2025:

	Options outstanding			Options exercisable	
Range of exercise prices	Number outstanding	Weighted-average remaining contractual life	Weighted-average exercise price	Number exercisable	Weighted-average exercise price
$ 1.00 - $ 5.00	525,000	3.9 years	$ 3.96	33,333	$ 4.38
5.01 - 10.00	1,192,500	2.7 years	5.72	805,144	5.82
10.01 - 15.00	15,000	0.4 years	12.32	15,000	12.32
$ 1.00 - $ 15.00	1,732,500	3.1 years	$ 5.24	853,477	$ 5.88

The Company records compensation expense equally over the annual three-year vesting period, based on the fair value of options granted to directors, officers and employees. In 2025, the Company granted 425,000 options with an estimated fair value of $387,000 or $0.91 per option using the Black-Scholes option pricing model with the following key assumptions:

	December 31, 2025
Weighted-average risk free interest rate (%)[1]	**2.80**
Weighted-average expected life (years)	**1.9**
Weighted-average volatility (%)[2]	**40.60**
Forfeiture rate (%)	**6.43**

(1) Risk-free interest rate is based on the weighted average Government of Canada benchmark bond yields for one, two, and three year terms to match corresponding vesting periods.

(2) The expected volatility is measured as the standard deviation of expected share price returns based on statistical analysis of historical weekly share prices for a representative period.

13. OIL AND GAS SALES, NET OF ROYALTIES

($ 000s)	**December 31, 2025**	December 31, 2024
Oil and gas sales		
Crude oil	**190,215**	229,249
Natural gas liquids	**22,946**	26,011
Natural gas	**34,713**	24,697
	247,874	279,957
Less royalties:		
Crown	**(22,453)**	(27,633)
Freehold, gross overriding royalties and other	**(9,050)**	(12,009)
	(31,503)	(39,642)
Oil and gas sales, net of royalties	**216,371**	240,315

14. OTHER INCOME

($ 000s)	**December 31, 2025**	December 31, 2024
Investment income	**319**	326
Administrative income	**237**	252
Gain on sale of property and equipment	**4,634**	178
Other income	**5,190**	756

15. SUPPLEMENTAL CASH FLOW INFORMATION

($ 000s)	December 31, 2025	December 31, 2024
Change in non-cash working capital:		
Accounts receivable	**(5,608)**	(414)
Crude oil inventory	**49**	7
Prepaid expenses	**(2,078)**	2,395
Abandonment deposit	**868**	(444)
Accounts payable and accrued liabilities	**765**	(855)
	(6,004)	689
Changes related to:		
Operating activities	**(3,150)**	5,297
Investing activities	**(2,854)**	(4,608)
	(6,004)	689

Finance expense

($ 000s)	December 31, 2025	December 31, 2024
Interest expense:		
Bank debt	**2,505**	3,970
Subordinated notes	**12,994**	-
Subordinated debenture	**826**	5,310
Subordinated term debt	**512**	8,541
	16,837	17,821
Accretion:		
Decommissioning liabilities	**3,970**	3,692
Subordinated notes	**807**	-
Subordinated debentures	**537**	3,287
Subordinated term debt	**121**	1,732
	5,435	8,711
Total finance costs	**22,272**	26,532
Interest paid:		
Expense	**16,837**	17,821
Change in interest accrued	**(5,907)**	-
Interest paid	**10,930**	17,821

16. FINANCIAL RISK MANAGEMENT

Financial Risk Factors

The Company undertakes transactions in a range of financial instruments including:

- Accounts receivable
- Accounts payable and accrued liabilities
- Bank debt
- Subordinated notes

The Company’s activities result in exposure to a number of financial risks including market risk (commodity price risk, interest rate risk, and foreign exchange risk), credit risk and liquidity risk.

The Company’s overall risk management program seeks to mitigate these risks and reduce the volatility on Bonterra’s financial performance. Financial risk is managed by senior management under the direction of the Board of Directors.

Bonterra is exposed to credit risk, liquidity risk and market risk as part of its normal course of business. The Company's overall risk management program seeks to mitigate these risks and reduce the volatility of Bonterra's financial performance. The Company does not speculatively trade in risk management contracts. Bonterra's risk management contracts are entered into to manage the risks relating to commodity prices from its business activities.

Liquidity Risk Management

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with its financial liabilities. The Company's financial performance and position are largely dependent on the commodity prices received for its oil and natural gas production. Commodity prices have fluctuated widely in recent years due to crude oil inventory levels, domestic infrastructure constraints, and global economic and geopolitical factors. Bonterra continues to retain available committed borrowing capacity that provides it with financial flexibility and the ability to meet ongoing obligations as they become due.

After examining the economic factors that are causing the liquidity risk facing the Company, the judgment applied to these factors, and the various initiatives that Bonterra has and will undertake to strengthen its financial position, the Company believes it will have sufficient liquidity to support its ongoing operations and meet its financial obligations as they come due for at least the next twelve months. There can be no assurance that the next borrowing base redetermination will not result in a borrowing base shortfall, and that the necessary funds or additional security will be available to eliminate the shortfall. Upon receipt of notice from the lenders, the shortfall would have to be remedied within 30 days or by such other means as acceptable to the lenders.

Credit Risk

Credit risk is the risk that a contracting party will not complete its obligations under a financial instrument and cause the Company to incur financial loss. Bonterra is exposed to credit risk on all financial assets included on the statement of financial position. To help mitigate this risk:

- The Company only enters into material agreements with creditworthy counterparties. These include major oil and gas companies or major Canadian chartered banks; and

- Agreements for product sales are primarily on 30-day renewal terms. Of the 31,386,000 accounts receivable balance at December 31, 2025 (December 31, 2024 - $25,778,000) over 62 percent (December 31, 2024 – 84 percent) relate to product sales or risk management contracts with national and international banks and oil and gas companies.

On a quarterly basis, Bonterra assesses if there has been any impairment of the financial assets of the Company. During the year ended December 31, 2025, there was no material impairment provision required on any of the financial assets of the Company. Bonterra does have credit risk exposure, as the majority of the Company's accounts receivable are with counterparties having similar characteristics. However, payments from Bonterra's largest accounts receivable counterparties have consistently been received within 30 days and the sales agreements with these parties are cancellable with 30 days' notice if payments are not received.

As at December 31, 2025, approximately $507,000 or 1.6 percent of the Company's total accounts receivable are aged over 90 days and considered past due (December 31, 2024 - $196,000 or 0.8 percent). The majority of these accounts are due from various joint venture partners. Bonterra actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production or netting payables when the accounts are with joint venture partners. Should the Company determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings.

If Bonterra subsequently determines an account is uncollectable, the account is written off with a corresponding charge to the allowance account. The Company's allowance for doubtful accounts balance at December 31, 2025 is $1,714,000 (December 31, 2024 - $1,733,000) with the expense being included in general and administrative expenses. There were no material accounts written off during the period.

The maximum exposure to credit risk is represented by the carrying amounts of accounts receivable. There are no material financial assets that Bonterra considers past due.

Capital Risk Management

The Company's objectives when managing capital, which it defines to include shareholders' equity, debt and working capital balances, are to safeguard Bonterra's ability to continue as a going concern, so that it can continue to provide returns to its shareholders and benefits for other stakeholders and to maintain a capital structure that provides a low cost of capital. To maintain or adjust the capital structure, the Company may adjust the current debt structure and/or issue common shares.

The Company monitors its capital structure based on the ratio of net debt (total debt adjusted for working capital) to EBITDA. This ratio is calculated using each quarter end net debt divided by the preceding twelve months' EBITDA. At December 31, 2025, the Company had a net debt to EBITDA level of 1.6:1 as compared to 1.2:1 as at December 31, 2024. The increase in Bonterra's net debt to EBITDA ratio is primarily due to an increase in debt from the Bonanza Asset Acquisition, the one-time costs associated with the debt refinancing transaction and a decrease in EBITDA from lower commodity prices. To provide cashflow protection, the Company has hedged approximately 40 percent of its forecasted oil and 25 percent of its forecasted natural gas production over the next nine months.

Section (a) of this note provides Bonterra's net debt to EBITDA ratio.

Section (b) addresses in more detail the key financial risk factors that arise from the Company's activities, including its policies for managing these risks.

a) Net debt to EBITDA ratio

The net debt and EBITDA amounts are as follows:

($ 000s)	**December 31, 2025**	December 31, 2024
Bank debt	**40,722**	46,211
Subordinated term debt[1]	**-**	35,750
Subordinated debentures	**-**	55,872
Subordinated notes	**135,713**	-
Current liabilities	**43,527**	61,389
Current assets	**(40,913)**	(32,012)
Net debt	**179,049**	167,210
Net earnings (loss)	**(17,125)**	10,203
Adjustments to net earnings (loss):		
Unrealized (gain) loss on risk management contracts	**(1,260)**	1,525
Gain on sale of property	**(4,634)**	-
Deferred consideration	**(955)**	(958)
Finance costs	**22,272**	26,532
Share-based compensation	**2,513**	2,293
Depletion and depreciation	**101,594**	97,137
Extinguishment of debt	**11,597**	-
Current income tax expense (recovery)	**(1,691)**	5,167
Deferred income tax recovery	**(2,998)**	(1,513)
EBITDA (trailing twelve months)	**109,313**	140,386
Net debt to EBITDA ratio	**1.6**	1.2

(3) Included in current liabilities is the current portion of the Subordinated Term Debt of $Nil (December 31, 2024 - $19,000,000).

b) Risks and mitigation

Market risk is the risk that the fair value or future cash flow of the Company’s financial instruments will fluctuate because of changes in market prices. Components of market risk to which Bonterra is exposed are discussed below.

Commodity Price Risk

The Company’s principal operation is the production and sale of crude oil, natural gas, and natural gas liquids. Fluctuations in prices of these commodities directly impact Bonterra’s performance and ability to continue with its dividends.

The Company has used various risk management contracts to set price parameters for a portion of its production. Bonterra has assumed the risk in respect of commodity prices, except for a small portion of physical delivery sales and risk management contracts to manage commodity risk derived from the Company’s higher operating cost areas.

Bonterra is exposed to credit risk, liquidity risk and market risk as part of its normal course of business. The Company’s overall risk management program seeks to mitigate these risks and reduce the volatility of Bonterra’s financial performance. Financial risk is managed by senior management under a risk management program approved by the Company’s Board of Directors.

Physical Delivery Sales Contracts

Bonterra enters into physical delivery sales contracts to manage commodity price risk. These contracts are considered normal executory sales contracts and are not recorded at fair value in the financial statements. As of December 31, 2025, the Company has the following physical delivery sales contracts in place.

Product	Type of contract	Volume	Term			Contract price ($)			
Gas	Physical collar - AECO Monthly[5]	2,500 GJ/day	Jan 1, 2026	to	Mar 31, 2026	1.75	to	2.70	CAD/GJ
Gas	Physical collar - AECO Monthly[5]	4,000 GJ/day	Jan 1, 2026	to	Mar 31, 2026	2.00	to	3.20	CAD/GJ
Gas	Fixed Price - AECO Daily[4]	2,500 GJ/day	Jan 1, 2026	to	Dec 31, 2026			3.30	CAD/GJ
Gas	Fixed Price - AECO Daily[4]	5,000 GJ/day	Apr 1, 2026	to	Mar 31, 2027			3.10	CAD/GJ

(1) "WTI" refers to West Texas Intermediate, a grade of light sweet crude oil used as benchmark pricing in the United States.
(2) "MSW Stream index" or "Edmonton Par" refers to the mixed sweet blend that is the benchmark price for conventionally produced light sweet crude oil in Western Canada.
(3) "MSW differential" is the primary difference between WTI and MSW steam index benchmark pricing.
(4) "AECO Daily" refers to a grade or heating content of natural gas used as daily index benchmark pricing in Alberta, Canada.
(5) "AECO Monthly" refers to a grade or heating content of natural gas used as monthly index benchmark pricing in Alberta, Canada.

Subsequent to December 31, 2025, the Company entered into the following physical delivery sales contract.

Product	Type of contract	Volume	Term			Contract price ($)	
Gas	Fixed Price - AECO Daily	4,000 GJ/day	Apr 1, 2026	to	Oct 31, 2026	1.29	CAD/GJ

Risk Management Contracts

($ 000s)	**December 31, 2025**	December 31, 2024
Risk management contracts		
Realized gain	**2,942**	3,569
Unrealized gain (loss)	**1,260**	(1,525)
	4,202	2,044

The Company also enters into financial derivative instruments or risk management contracts to manage commodity price risk. These contracts are not considered normal executory sales contracts and are recorded at fair value in the financial statements.

As of December 31, 2025, the Company has the following risk management contracts in place.

Product	Type of contract	Volume	Term			Contract price ($)			
Oil	Financial collar - WTI	250 BBL/day	Jan 1, 2026	to	Mar 31, 2026	60.00	to	72.50	USD/BBL
Oil	Financial collar - WTI	250 BBL/day	Jan 1, 2026	to	Mar 31, 2026	55.00	to	70.25	USD/BBL
Oil	Financial collar - WTI	500 BBL/day	Jan 1, 2026	to	Mar 31, 2026	60.00	to	71.90	USD/BBL
Oil	Financial collar - WTI	250 BBL/day	Jan 1, 2026	to	Jun 30, 2026	60.00	to	66.75	USD/BBL
Oil	Fixed price - WTI	500 BBL/day	Jan 1, 2026	to	Jun 30, 2026			63.00	USD/BBL
Oil	Fixed price - WTI	500 BBL/day	Jan 1, 2026	to	Dec 31, 2026			60.04	USD/BBL
Gas	Financial collar - AECO Monthly	5,000 GJ/day	Jan 1, 2026	to	Mar 31, 2026	1.75	to	2.74	CAD/GJ

Subsequent to December 31, 2025 the Company entered into the following risk management contract.

Product	Type of contract	Volume	Term			Contract price ($)			
Oil	Fixed price - WTI	500 BBL/day	Feb 1, 2026	to	Dec 31, 2026			60.00	USD/BBL
Oil	Fixed price - WTI	500 BBL/day	Apr 1, 2026	to	Dec 31, 2026			60.25	USD/BBL
Oil	Fixed price - WTI	500 BBL/day	Mar 1, 2026	to	Jun 30, 2026			61.03	USD/BBL
Oil	Fixed price - WTI	250 BBL/day	Mar 1, 2026	to	Dec 31, 2026			64.20	USD/BBL
Oil	Financial collar - WTI	500 BBL/day	Jul 1, 2026	to	Dec 31, 2026	60.00	to	66.75	USD/BBL
Oil	Fixed price - WTI	250 BBL/day	Apr 1, 2026	to	Jun 30, 2026			80.95	USD/BBL

Interest Rate Risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in market interest rates. Interest rate risk arises from interest bearing financial assets and liabilities that the Company uses. Bonterra's principal exposure is borrowings that have a variable interest rate which gives rise to a cash flow interest rate risk.

As of December 31, 2025, the Company's debt facilities consist of a $125,000,000 syndicated revolving credit facility, and a $25,000,000 non-syndicated revolving credit facility, and $135,000,000 senior second lien subordinated notes. The borrowings under the total bank facilities are at bank prime plus or minus various percentages as well as by means of the Canadian Overnight Repo Rate Average ("CORRA") within Bonterra's credit facility.

The subordinated notes are at a fixed interest rate of 10.5 percent. Bonterra manages its exposure to interest rate risk on its floating interest rate debt through entering into various term lengths on its term CORRAs but in no circumstances do the terms exceed six months.

Sensitivity Analysis

Based on historic movements and volatilities in the interest rate markets and management's current assessment of the financial markets, the Company believes that a one percent variation in the Canadian prime interest rate is reasonably possible over a 12-month period. A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by $314,000.

Foreign Exchange Risk

The Company has no foreign operations and currently sells all of its product sales in Canadian currency. However, Bonterra is exposed to currency risk in that crude oil is priced in US currency, then converted to Canadian currency. The Company currently has no outstanding risk management agreements. It will assume full risk in respect of foreign exchange fluctuations.

17. COMMITMENTS AND FINANCIAL LIABILITIES

Bonterra has the following maturity schedule for its financial liabilities and commitments:

($ 000s)	Recognized on Financial Statements	Less than 1 year	Over 1 year to 3 years	Over 3 years to 5 years	Over 5 years to 7 years	Total
Accounts payable and accrued liabilities	Yes - Liability	37,136	-	-	-	37,136
Bank debt	Yes - Liability	-	40,722	-	-	40,722
Subordinated notes [1]	Yes - Liability	-	-	135,000	-	135,000
Future interest	No	14,175	28,350	15,356	-	57,881
Firm service commitments	No	1,246	1,932	912	153	4,243
Office lease commitments	No	1,140	1,684	1,638	-	4,462
Total		53,697	72,688	152,906	153	279,444

[6] Principal amount.

The Company has entered into firm service gas transportation agreements in which it guarantees certain minimum volumes of natural gas will be shipped on various gas transportation systems. The terms of the various agreements expire in one to seven years. The future minimum payment amounts for the firm service gas transportation agreements are calculated using current tariff rates.

Bonterra also has non-cancellable office lease commitments for building and office equipment. The building and office equipment leases have an average remaining life of 5.0 years.

CORPORATE INFORMATION

Board of Directors

Andy J. Mah - Chair
John J. Campbell
David M. Humphreys
Stacey E. McDonald
Patrick G. Oliver
Jacqueline R. Ricci

Officers

Patrick G. Oliver, President & CEO
Scott A. Johnston, CFO & Corporate Secretary
Brad A. Curtis, Senior VP, Business Development

Registrar and Transfer Agent

Odyssey Trust Company

Auditors

Deloitte LLP

Solicitors

Borden Ladner Gervais LLP

Bankers

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