Bonterra.

# Bonterra Energy Announces Year-End 2025 Results and Reserves Evaluation; Achieves Record Annual Production

Mar 12, 2026

CALGARY, Alberta, March 12, 2026 (GLOBE NEWSWIRE) -- Bonterra Energy Corp. (TSX: BNE; OTCID: BNEFF) ("**Bonterra**" or the "**Company**") is pleased to announce its financial and operating results for the fourth quarter and year ended December 31, 2025, achieving a record annual production, together with highlights of an independent oil and gas reserves evaluation (the "Sproule Report") prepared by Sproule International Limited ("Sproule"), effective December 31, 2025. The related financial statements and notes, as well as management's discussion and analysis along with the annual information form for the period ended December 31, 2025, are available on SEDAR+ www.sedarplus.ca and on our website www.bonterraenergy.com.

- **Record annual production of 15,513 BOE per day**, exceeding revised guidance and representing a 5% increase from the prior year
- **Expanded Charlie Lake core area** through the closing of the previously announced Bonanza asset acquisition, consisting of low-decline oil pools producing approximately 760 BOE per day(3) and 21 top-tier drilling locations
- **Achieved reserves growth** across Total Proved ("TP") and Total Proved Plus Probable ("TPP") reserve categories of 3%, underpinning TPP Reserve Life Index of 19.4 years; Reduced TP and TPP F&D costs(2) to $12.72/BOE and $14.93/BOE driving recycle ratios(2) of 2.1x and 1.8x, respectively
- **Capital spending of $69.9 million**, in line with guidance
- **Adjusted Free Funds Flow(1) of $17.2 million**, an increase of 65% versus prior year
- **Reaffirms 2026 guidance**, with annual production expected to range from 16,200 to 16,400 BOE per day(3) and capital expenditures expected to be $75–$80 million

Patrick Oliver, President and Chief Executive Officer, stated: "It's fair to say that 2025 was a breakthrough year for Bonterra, reflecting our focus on disciplined growth. We took several key steps to strengthen both our financial position and our asset base, notably:

- Successfully executing our Charlie Lake drilling program, which was the key driver in achieving an annual production record and supported improved capital efficiency;
- Completing a strategic acquisition to further expand our Charlie Lake core area, which increased tier-1 drilling inventory;
- Continuing delineation drilling in our Montney land base, including successfully drilling our first three-mile horizontal Montney well; and
- Increasing the liquidity of the business through our Canadian high-yield debt refinancing transaction."

Mr. Oliver added, "By optimizing our stable Cardium production base and leveraging our high-impact assets in the Charlie Lake and Montney, we were able to deliver record production using significantly less capital. We are currently in the delineation phase on both assets, and with low reserve bookings to date, we see significant resource capture and growth opportunities ahead, creating sustainable long-term value for our shareholders."

**2025 Financial and Operating Highlights**

**Production** averaged 15,513 BOE per day during 2025, representing a 5% increase from 14,846 BOE per day in the prior year, which was primarily attributable to the execution of the Company's 2025 drilling program and the Pembina Cardium well reactivation activities completed early in the year. Fourth quarter 2025 volumes averaged 15,254 BOE per day(3).

**Funds Flow[1] and Adjusted Free Funds Flow[1]** totaled $94.2 million ($2.57 per fully diluted share) and $17.2 million ($0.47 per fully diluted share) respectively. Funds Flow decreased year over year by 20% primarily driven by decreased crude oil pricing and Adjusted Free Funds Flow increased by 65% despite lower crude oil prices primarily driven by a more efficient capital program in 2025.

**Field Netback and Cash Netbacks[1]** in 2025 averaged $22.05 per BOE and $16.63 per BOE, respectively, with WTI crude oil prices averaging US$64.81 per barrel and AECO natural gas prices averaging $1.67 per mcf in 2025.

**Production costs** averaged $16.69 per BOE in 2025 compared to $16.54 per BOE in 2024. The marginal increase was 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.

**Capital expenditures** totaled $69.9 million in 2025, in line with the Company's previously provided annual capital expenditure guidance of $65 to $70 million:

- $41.0 million was allocated to the drilling of 9 gross (8.4 net) operated wells, of which 7 gross (6.5 net) wells were completed, equipped, and tied-in, and to the drilling of 9 gross (1.5 net) non-operated wells. The two (1.9 net) remaining drilled and uncompleted ("DUC") wells have been completed and tied-in during the first quarter of 2026; and
- $28.9 million was directed toward land and lease acquisitions, infrastructure, recompletions and compressor upgrades.

**Bonanza Asset Acquisition** closed on December 18, 2025, for cash consideration of $15.3 million, after closing adjustments:

- Low decline base production: Approximately 760 BOE per day[3] of existing production in low decline oil pools
- Increased area footprint: 41 net sections of land in the Greater Bonanza Area adjacent to existing Charlie Lake operations
- Charlie Lake drilling inventory: 21 identified top tier drilling locations complementary to its existing Charlie Lake inventory in addition to 3 low-risk infill locations in the Doig formation
- Synergistic infrastructure: Strategic owned and operated infrastructure footprint of underutilized compression, batteries and gathering pipelines creates immediate half cycle drilling opportunities on the acquired lands and proximal existing lands and offers new gas processing optionality in the Greater Bonanza Area

**Net Debt[1]** totaled $179.0 million at year end, representing a net debt to EBITDA level of 1.6:1 as compared to 1.2:1 as at December 31, 2024. The increase in 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.

**Normal Course Issuer Bid** initiated in April, saw the Company repurchase 749,900 common shares for cancellation at an average price of $3.56 per share, representing approximately 2% of the outstanding shares at December 31, 2024.

**2025 Financial and Operating Results**

| 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 |

*Notes for the table above:*

(1) *Funds flow is a non-IFRS measure. See advisories later in this press release.*

(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 have 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 a non-IFRS measure. See advisories later in this press release.*

*(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.*

**Operations Update**

**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[3] representing 23% of December 2025 corporate production.

**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[3] representing 5% of December 2025 corporate production.

**2026 Outlook**

The Company reaffirms its production and capital guidance for 2026 outlined below:

- Annual average production range of 16,200 to 16,400 BOE per day[3], weighted approximately 50 to 52% to oil and liquids; and
- Capital expenditure range of $75 million to $80 million.

The 2026 capital program is geared to grow corporate production through capital allocation across all three of the Company's assets. Capital directed to the Cardium will further enhance the optimization of the base cash flow stream, and the Charlie Lake and Montney activity is planned to increase production exposure in these plays and to further prove out the value of the resource in these high-impact assets, including testing the new lands from our recent acquisition.

Bonterra remains committed to a disciplined approach to managing leverage levels and will focus use of Free Funds Flow to debt repayment and share buybacks in 2026.

The Company retains capital flexibility for the remainder of the year in response to prevailing commodity price conditions.

To mitigate risk and add stability during periods of market volatility, hedges have been put in place on approximately 48% of Bonterra's expected crude oil and 25% of its natural gas production through the first six months of 2026. Through the first six months of 2026, Bonterra has secured WTI prices between $55.00 USD to $80.95 USD per bbl on 3,044 bbls per day; and natural gas prices between $1.29 to $3.30 per GJ on approximately 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.

**2025 Reserves Highlights**

The Company is pleased to announce the summary results of its independent reserve report prepared by Sproule International Limited with an effective date of December 31, 2025. The Sproule Report reflects the success of the 2025 capital program driven by the Company's Charlie Lake and Montney resource plays.

The following provides a summary of specific details from the Sproule Report, which was prepared following the guidelines, criteria, and methodologies outlined in the Canadian Oil and Gas Evaluation Handbook ("COGE Handbook") and National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Further reserves-related information, as mandated by NI 51-101, will be incorporated into Bonterra's Annual Information Form, to be filed on the Company's profile at www.sedarplus.ca and available on the Company's website.

- **Reserves increases in TP and TPP categories:**
  - Unchanged year over year - Proved Developed Producing ("PDP") reserves of 34.3 million BOE
  - 3% increase year over year - TP reserves of 87.8 million BOE
  - 3% increase year over year - TPP reserves of 109.7 million BOE
- **Net present value of future net revenue** discounted at 10% (before tax) for TPP totaled $1.2 billion, while TP totaled $859.2 million and PDP totaled $468.5 million
- **Reserve Life Index ("RLI")**[2] for TPP, TP, and PDP of approximately 19.4 years, 15.5 years and 6.1 years, respectively (based on 2025 average production of 15,513 BOE per day)
- **Reserve Replacement**[2] **of** 99% of 2025 production on a PDP basis, 150% on a TP basis and 164% on a TPP basis
- **F&D Costs**[2] including FDC of $12.72/BOE on TP and $14.93/BOE on TPP
- **Recycle ratio**[2] including FDC of 2.1 times on TP reserves, 1.8 times on TPP reserves
- **Future Development Capital** ("FDC") for TP is forecast to be $804 million, an increase of 2% or $18 million compared to 2024 TP FDC of $786 million

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

| | Light and Medium Crude Oil | Conventional Natural Gas | Natural Gas Liquids | Oil Equivalent | Future Development Capital |
|---|---|---|---|---|---|
| | (MBbl) | (MMcf) | (MBbl) | (MBoe) | ($000s) |
| Proved | | | | | |
| Developed Producing | 15,418.6 | 93,403 | 3,340.3 | 34,325.9 | - |
| Developed Non-Producing | 1,619.3 | 7,081 | 247.1 | 3,046.6 | 5,681 |
| Undeveloped | 23,033.0 | 137,204 | 4,547.8 | 50,448.2 | 798,583 |
| **Total Proved** | **40,070.9** | **237,688** | **8,135.1** | **87,820.7** | **804,264** |
| Total Probable | 10,001.3 | 59,240 | 2,013.1 | 21,887.6 | 18,298 |
| **Total Proved plus Probable** | **50,072.2** | **296,927** | **10,148.2** | **109,708.3** | **822,562** |

**Reconciliation of Company Gross Reserves by Principal Product Type as of December 31, 2025**

| | **Light & Medium Crude Oil** | | **Conventional Natural Gas** | | **Natural Gas Liquids** | | **Oil Equivalent** | |
|---|---|---|---|---|---|---|---|---|
| | Total Proved | Proved + Probable | Total Proved | Proved + Probable | Total Proved | Proved + Probable | Total Proved | Proved + Probable |
| | (MBbl) | (MBbl) | (MMcf) | (MMcf) | (MBbl) | (MBbl) | (Mboe) | (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 | 1,002 | 7,495 | 9,666 |
| Acquisitions (2) | 762 | 952 | 9,605 | 12,022 | 196 | 246 | 2,559 | 3,202 |
| Dispositions (3) | (169) | (218) | (32) | (42) | (0) | (0) | (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** | **296,927** | **8,135** | **10,148** | **87,821** | **109,708** |

*Notes for table above:*

(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 average commodity price forecasts of Sproule, GLJ Petroleum Consultants and McDaniels & Associates Consultants Ltd. for December 31, 2024 compared to December 31, 2025 commodity 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**

| ($M) | **Net Present Value Before Income Taxes Discounted at (% per year)** | | | |
|---|---|---|---|---|
| Reserves Category: | **0%** | **5%** | **10%** | **15%** |
| **Proved** | | | | |
| Producing | 749,746 | 577,152 | 468,500 | 396,003 |
| 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 plus Probable** | **2,425,339** | **1,617,228** | **1,168,068** | **893,882** |

**Future Development Capital, F&D Costs[2] and Recycle Ratios[2]**

FDC reflects Sproule's best estimate of the costs to bring Bonterra's proved and probable developed and undeveloped reserves on production. Changes in forecasted FDC occur annually because of development activities, acquisition and disposition activities, changes in capital cost estimates based on improvements in well design and performance, changes in service costs and changes to cost estimates for capital activities that do not directly drive additions in reserves or production.

Over the past three years, Bonterra has incurred the following finding, development and acquisition ("FD&A") and finding and development ("F&D") costs both excluding and including FDC:

| | **TP Reserves Net Additions** | | | | **TPP Reserves Net Additions** | | | |
|---|---|---|---|---|---|---|---|---|
| | **2025** | **2024** | **2023** | **3 Yr Avg[4]** | **2025** | **2024** | **2023** | **3 Yr Avg[4]** |
| **FD&A Costs per BOE[1,2,3,6]** | | | | | | | | |
| 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[1,2,3,6]** | | | | | | | | |
| 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 |
| **Recycle Ratio[2,5,6]** | | | | | | | | |
| F&D (including FDC) | 2.1 | 1.6 | 0.9 | 1.6 | 1.8 | 1.5 | 1.1 | 1.5 |
| F&D (Excluding FDC) | 2.7 | 2.7 | 1.4 | 2.3 | 2.4 | 2.4 | 1.6 | 2.2 |

*Notes for table above:*

(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 capital 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) *Recycle ratio is defined as field netback per BOE divided by F&D costs on a per BOE basis. Field netback is a Non-IFRS Measure, see "Cautionary Statements." On a BOE basis, Bonterra's (unaudited) field netback used in the above calculations are as follows: 2025 - $22.05; 2024 - $28.34; 2023 - $37.01; Three-year weighted average - $28.91.*

(6) *"FD&A Cost", "F&D Cost", and "Recycle Ratio" do not have standardized meanings and therefore may not be comparable with the calculation of similar measures for other entities. See "Information Regarding Oil and Gas Disclosure" in this news release.*

**Notes Excluding Tables**

(1) Non-IFRS measure. See advisories contained in this press release.

(2) See "Information Regarding Oil and Gas Disclosure" contained in this press release.

(3) See "Information Regarding Product Types" contained in this press release.

**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. The 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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**Cautionary Statements**

This summarized press release should not be considered a suitable source of information for readers who are unfamiliar with Bonterra Energy Corp. and should not be considered in any way as a substitute for reading the full report for the year ended December 31, 2025. For the full report, please go to www.bonterraenergy.com.

**Information Regarding Oil and Gas Disclosure**

Bonterra's oil and gas reserves statement for the year ended December 31, 2025, which includes complete disclosure of its oil and gas reserves and other oil and gas information in accordance with NI 51-101, is contained within its Annual Information Form which is available on Bonterra's SEDAR profile at www.sedarplus.ca or on the Company's website. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. In relation to the disclosure of estimates for individual properties or subsets thereof, 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. The Company's belief that it will establish additional reserves over time with the conversion of probable undeveloped reserves into proved reserves is a forward-looking statement and is based on certain assumptions and is subject to certain risks, as discussed below under the heading "Forward-Looking Information".

This press release contains metrics commonly used in the oil and natural gas industry, such as "reserve life index", "recycle ratio", "reserve replacement", "finding and development costs", "finding and development recycle ratio", "finding, development and acquisition costs", and "field netbacks". Each of these metrics are determined by Bonterra as specifically set forth in this news release. These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included to provide readers with additional information to evaluate the Company's performance, however, such metrics should not be unduly relied upon for investment or other purposes. Management uses these metrics for its own performance measurements and to provide readers with measures to compare Bonterra's performance over time.

F&D costs are calculated as the sum of development capital plus the change in FDC for the period when appropriate, divided by the change in reserves that are characterized as development for the period. Development capital is a non-GAAP financial measure used as a component of F&D costs. Management uses F&D costs as a measure of capital efficiency for organic reserves development. "FD&A costs" are calculated as the sum of development capital plus acquisition capital plus the change in FDC for the period when appropriate, divided by the change in total reserves, other than from production, for the period. Development capital and acquisition capital are non-GAAP financial measures used as components of FD&A costs. Management uses FD&A costs as a measure of capital efficiency for organic and acquired reserves development.

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

Both F&D and FD&A costs take into account reserves revisions during the year on a per BOE basis. The aggregate of the costs incurred in the financial year and changes during that year in estimated FDC may not reflect total F&D costs related to reserves additions for that year. Finding and development costs both including and excluding acquisitions and dispositions have been presented in this press release because acquisitions and dispositions can have a significant impact on Bonterra's ongoing reserves replacement costs and excluding these amounts could result in an inaccurate portrayal of its cost structure.

Reserve life index is an index reflecting the theoretical production life of a property if the remaining reserves were to be produced out at current production rates. The index is calculated by dividing the reserves in the selected reserve category at a certain date by the annual production for the period.

Recycle ratio is defined as field netback per BOE divided by F&D costs on a per BOE basis.

Management uses these oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare Bonterra's performance over time, however, such measures are not reliable indicators of the Company's future performance and future performance may not compare to the performance in previous periods. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this press release, should not be relied upon for investment or other purposes.

References in this press release 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 of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production of Bonterra. The Company cautions that such results should be considered preliminary.

**Non-IFRS and Other Financial Measures**

In this press release, the Company refers to certain financial measures to analyze operating performance, which are not standardized measures recognized under IFRS® and do not have a standardized meaning prescribed by IFRS. These measures are commonly utilized in the oil and gas industry and are considered informative by management, shareholders and analysts. These measures may differ from those made by other companies and accordingly may not be comparable to such measures as reported by other companies. This release contains the terms “funds flow”, “capital expenditures”, “free funds flow”, “adjusted free funds flow”, "net debt", "net debt to EBITDA ratio", “field netback” and “cash netback” to analyze operating performance. Non-IFRS and other financial measures within this release may refer to forward-looking non-IFRS and other financial measures and are calculated consistently with the three months and year ended December 31, 2025 reconciliations as outlined below.

**Funds Flow**

Funds flow is a non-IFRS financial measure. Funds flow is 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 considers funds flow from operations to be a key measure to assess the Company's management of capital. Funds flow is an indicator as to whether adjustments are necessary to the level of capital expenditures. For example, in periods where funds flow from operations is negatively impacted by reduced commodity pricing, capital expenditures may need to be reduced or curtailed to preserve the Company's capital. Management believes that by excluding the impact of changes in non-cash working capital, decommissioning expenditures, adjusting for interest expense in the period, and including investment income received and proceeds on sale of investments funds flow from operations provides a useful measure of Bonterra's ability to generate the funds necessary to manage the capital needs of the Company.

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 | |
|---|---|---|---|---|
| **($ millions)** | **December 31, 2025** | December 31, 2024 | **December 31, 2025** | December 31, 2024 |
| Cash flow from operating activities | **21.5** | 28.6 | **89.5** | 115.0 |
| Adjusted for: | | | | |
| Changes in non-cash working capital | **2.5** | (2.1) | **3.2** | (5.3) |
| Interest expense | **(4.2)** | (4.3) | **(16.8)** | (17.8) |

| | | | | |
|---|---|---|---|---|
| Interest paid | **0.7** | 5.6 | **10.9** | 17.8 |
| Decommissioning expenditures | **1.6** | 2.2 | **7.1** | 7.2 |
| Investment income received | **-** | 0.1 | **0.3** | 0.4 |
| Proceeds on sale of investments | **-** | - | **-** | 1.4 |
| **Funds flow** | **22.1** | 30.1 | **94.2** | 118.7 |

**Capital Expenditures**

Capital expenditures are a non-IFRS financial measure. Management utilizes capital expenditures to measure total cash capital expenditures incurred in the period. Capital expenditures represent exploration and evaluation and property, plant and equipment expenditures in the statement of cash flows in the Company's annual audited financial statements as follows:

| | Three months ended | | Year ended | |
|---|---|---|---|---|
| **($ millions)** | **December 31, 2025** | December 31, 2024 | **December 31, 2025** | December 31, 2024 |
| Comprised of: | | | | |
| Exploration and evaluation expenditures | **1.5** | 0.2 | **2.3** | 1.2 |
| Property, plant and equipment expenditures | **14.8** | 22.2 | **67.6** | 99.9 |
| **Capital Expenditures** | **16.3** | 22.4 | **69.9** | 101.1 |

**Free Funds Flow**

Management utilizes free funds flow to assess the amount of funds available for future capital allocation decisions. It is calculated as funds flow plus proceeds on sale of property less capital expenditures, acquisition and decommissioning expenditures settled from the statement of cash flows.

| | Three months ended | | Year ended | |
|---|---|---|---|---|
| **($ millions)** | **December 31, 2025** | December 31, 2024 | **December 31, 2025** | December 31, 2024 |
| Funds flow | **22.1** | 30.1 | **94.2** | 118.7 |
| Adjusted for: | | | | |
| Capital expenditures | **(16.3)** | (22.4) | **(69.9)** | (101.1) |
| Acquisition | **(15.3)** | - | **(15.3)** | (23.6) |
| Proceeds on sale of property | **-** | - | **2.0** | 0.1 |
| Decommissioning expenditures | **(1.6)** | (2.2) | **(7.1)** | (7.2) |
| **Free funds flow (deficiency)** | **(11.1)** | 5.5 | **3.9** | (13.1) |

**Adjusted Free Funds Flow**

Management utilizes adjusted free funds flow to assess the amount of funds available excluding acquisition expenditures and dispositions. It is calculated as free funds flow plus acquisition expenditure less sale of property from the statement of cash flows.

| | Three months ended | | Year ended | |
|---|---|---|---|---|
| **($ millions)** | **December 31, 2025** | December 31, 2024 | **December 31, 2025** | December 31, 2024 |
| Free funds flow (deficiency) | **(11.1)** | 5.5 | **3.9** | (13.1) |
| Adjusted for: | | | | |
| Acquisition | **15.3** | - | **15.3** | 23.6 |
| Proceeds on sale of property | **-** | - | **(2.0)** | (0.1) |
| **Adjusted free funds flow** | **4.2** | 5.5 | **17.2** | 10.4 |

**Net Debt and Net Debt to EBITDA Ratio**

Net debt is a non-IFRS financial measure. Net debt is defined as current liabilities less current assets plus long-term bank debt, subordinated debentures, subordinated term debt and subordinated notes. 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. Net debt to EBITDA is a non-IFRS ratio. Net debt to EBITDA ratio is defined as net debt at the end of the period divided by EBITDA for the trailing twelve months. For more information about net debt or net debt to EBITDA ratio please refer to Note 16 of Bonterra's December 31, 2025 annual audited financial statements.

The following is a summary of net debt and net debt to EBITDA and a reconciliation of trailing twelve-month EBITDA to the most directly comparable IFRS measure, "Net earnings":

| ($ millions) | **December 31, 2025** | December 31, 2024 |
|---|---|---|
| Bank debt | **40.7** | 46.2 |
| Subordinated term debt | **-** | 35.8 |
| Subordinated debentures | **-** | 55.9 |
| Subordinated notes | **135.7** | - |
| Current liabilities | **35.6** | 61.4 |
| Current assets | **(33.0)** | (32.0) |
| **Net debt** | **179.0** | 167.3 |
| | | |
| Net earnings (loss) | **(17.1)** | 10.2 |
| Adjustments to net earnings (loss): | | |
| Unrealized loss (gain) on risk management contracts | **(1.3)** | 1.5 |
| Gain on sale of property | **(4.6)** | - |
| Deferred consideration | **(1.0)** | (1.0) |
| Finance costs | **22.3** | 26.5 |
| Share-based compensation | **2.5** | 2.3 |
| Depletion and depreciation | **101.6** | 97.1 |
| Extinguishment of debt | **11.6** | - |
| Current income tax expense (recovery) | **(1.7)** | 5.2 |
| Deferred income tax recovery | **(3.0)** | (1.5) |
| **EBITDA (trailing twelve months)** | **109.3** | 140.3 |
| **Net debt to EBITDA ratio** | **1.6** | 1.2 |

**Field and Cash Netback**

Field netback is a non-IFRS financial measure, calculated as revenue and realized risk management contract gain (loss) minus royalties and operating expenses divided by total BOEs for the period. Field netback per BOE is a non-IFRS ratio, calculated as field netback divided by total barrels of oil equivalent produced during a specific period of time. There is no comparable measure in accordance with IFRS. This metric is used by management to evaluate the Company's ability to generate cash margin on a unit of production basis.

Cash netback is a non-IFRS financial measure, calculated as field netback less interest expense, general and administrative expense and current income tax expense divided by total BOEs for the period. Cash netback per BOE is a non-IFRS ratio, calculated as cash netback divided by total barrels of oil equivalent produced during a specific period of time. There is no comparable measure in accordance with IFRS. This metric is used by management to evaluate the Company's ability to generate cash flow from continuing corporate activities on a unit of production basis.

Field and cash netback are calculated on per unit basis as follows:

| | Three months ended | | Year ended | |
|---|---|---|---|---|
| **($ millions)** | **December 31, 2025** | December 31, 2024 | **December 31, 2025** | December 31, 2024 |
| Oil and gas sales | **57.8** | 69.7 | **247.9** | 280.0 |
| Realized gain (loss) on risk management contracts | **1.6** | 1.6 | **2.9** | 3.6 |
| Royalties | **(6.1)** | (9.5) | **(31.5)** | (39.6) |
| Production costs | **(22.4)** | (23.1) | **(94.5)** | (90.0) |
| **Field Netback** | **30.9** | 38.7 | **124.8** | 154.0 |
| Office and administration | **(1.6)** | (1.3) | **(5.6)** | (5.2) |
| Employee compensation | **(5.1)** | (3.9) | **(10.5)** | (9.1) |
| Administrative and investment income | **0.1** | 0.1 | **0.6** | 0.6 |
| Proceeds on sale of investments | **-** | - | **-** | 1.4 |
| Interest expense | **(4.2)** | (4.3) | **(16.8)** | (17.8) |
| Current income (tax) recovery | **2.0** | 0.8 | **1.7** | (5.2) |
| **Cash Netback** | **22.1** | 30.1 | **94.2** | 118.7 |

| | | | | |
|---|---|---|---|---|
| **Barrel of oil equivalent (BOE)** | **1,403,369** | 1,330,294 | **5,662,146** | 5,433,622 |
| **Field Netback ($ per BOE)** | **21.97** | 26.94 | **22.05** | 28.34 |
| **Cash Netback ($ per BOE)** | **15.76** | 20.95 | **16.63** | 21.84 |

**Information Regarding Product Types**

References to gas or natural gas and NGLs in this press release refer to conventional natural gas and natural gas liquids product types, respectively, as defined in National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities, except where specifically noted otherwise. The Company's aggregate average production for the past eight quarters and the references to "crude oil", "NGLs", and "natural gas" reported herein consist of the following product types, as defined in NI 51-101 and using a conversion ratio of 1 Bbl : 6 Mcf where applicable:

| | 2025 | | | | 2024 | | | |
|---|---|---|---|---|---|---|---|---|
| | Q4 | Q3 | Q2 | Q1 | Q4 | Q3 | Q2 | Q1 |
| **Average daily production** | | | | | | | | |
| Light oil (bbls/d) | **6,274** | 6,051 | 6,794 | 6,546 | 7,306 | 7,177 | 7,282 | 7,068 |
| NGLs (bbls/d) | **1,507** | 1,353 | 1,508 | 1,679 | 1,619 | 1,410 | 1,248 | 1,155 |
| Conventional natural gas (MCF/d) | **44,839** | 42,336 | 48,584 | 46,390 | 37,214 | 34,241 | 32,286 | 31,448 |
| Total (BOE/d) | **15,254** | 14,460 | 16,399 | 15,957 | 15,128 | 14,294 | 13,911 | 13,464 |

- 2026 annual average production, at the midpoint of the guidance range, is anticipated to be comprised of approximately 40% light crude oil, 11% NGLs and 49% conventional natural gas.
- On December 18, 2025, the Company closed the acquisition of the Bonanza assets, adding low-decline production with a weighted mix of approximately 32% light crude oil, 5% NGLs and 63% conventional natural gas.
- Charlie Lake production for the month of December 2025 comprised approximately 36% light crude oil, 5% NGLs and 59% conventional natural gas.
- Montney production for the month of December 2025 comprised approximately 28% light crude oil, 15% NGLs and 57% conventional natural gas.

**Forward Looking Information**

Certain statements contained in this release 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 release includes, but is not limited to: the Company's 2026 financial and operating guidance relating to production and capital expenditures; the Company's 2026 priorities and outlook; exploration and development activities; plans relating to repayment of indebtedness and share buybacks; reserve estimates; future net revenue; F&D costs and future development capital; 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; 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.

In addition, to the extent that any forward-looking information presented herein constitutes future-oriented financial information or financial outlook, as defined by applicable securities legislation, such information has been approved by management of the Company and has been presented to provide management's expectations used for budgeting and planning purposes and for providing clarity with respect to the Company's strategic direction based on the assumptions presented herein and readers are cautioned that this information may not be appropriate for any other purpose.

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.

**Frequently Recurring Terms**

Bonterra uses the following frequently recurring terms in this press release: “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; 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**

All amounts in this press release are stated in Canadian dollars unless otherwise specified. The reporting and the functional currency of the Company is the Canadian dollar.

*The TSX does not accept responsibility for the accuracy of this release.*