

Bonterra Energy Announces Third Quarter 2025 Financial Results and Operations Update

The Company Achieves a 7% Increase in YTD Production, Reduces Net Debt, and Maintains Production and Capital Expenditure Guidance Ranges

CALGARY, Alberta, Nov. 13, 2025 (GLOBE NEWSWIRE) — Bonterra Energy Corp. (TSX: BNE) (“Bonterra” or the “Company”) is pleased to announce its financial and operating results for the three and nine months ended September 30, 2025. The related unaudited condensed financial statements and notes for the third quarter, as well as management’s discussion and analysis (“MD&A”), are available on SEDAR+ at www.sedarplus.ca and on Bonterra’s website at www.bonterraenergy.com.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

As at and for the periods ended (\$ 000s except for \$ per share and \$ per BOE)	Three months ended		Nine months ended		
	September 30, 2025	September 30, 2024	September 30, 2025	September 30, 2024	
FINANCIAL					
Revenue – realized oil and gas sales	55,166	69,204	190,041	210,258	
Funds flow ⁽¹⁾	21,330	30,066	72,057	88,568	
Per share – basic	0.59	0.81	1.96	2.37	
Per share – diluted	0.58	0.81	1.93	2.37	
Cash flow from operations	8,344	31,531	67,954	86,365	
Per share – basic	0.23	0.84	1.85	2.32	
Per share – diluted	0.23	0.84	1.82	2.31	
Net earnings (loss) ⁽²⁾	(3,554)	4,258	(12,477)	12,416	
Per share – basic	(0.10)	0.11	(0.34)	0.33	
Per share – diluted	(0.10)	0.11	(0.33)	0.33	
Capital expenditures	14,783	24,095	53,584	78,638	
Oil and gas property acquisition ⁽³⁾	-	-	-	24,234	
Total assets			935,536	984,065	
Net debt ⁽⁴⁾			167,803	168,278	
Bank debt			26,011	41,871	
Shareholders’ equity			526,565	542,344	
OPERATIONS					
Light oil	-bbl per day	6,051	6,775	6,462	6,656
	-average price (\$ per bbl)	81.92	94.30	84.30	95.09
NGLs	-bbl per day	1,353	1,538	1,512	1,475
	-average price (\$ per bbl)	40.42	47.44	42.95	46.24
Conventional natural gas	- MCF per day	42,336	42,039	45,755	38,730
	- average price (\$ per MCF)	1.16	0.96	1.89	1.71

Total BOE per day ⁽⁵⁾	14,460	15,320	15,600	14,586
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⁽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. See "Non-IFRS and Other Financial Measures".

⁽²⁾ Net loss for the nine months ended September 30, 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⁾ 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. See "Non-IFRS and Other Financial Measures".

⁽⁵⁾ 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.

FINANCIAL & OPERATING HIGHLIGHTS

- **Production** averaged 15,600 BOE per day during the first nine months of 2025, a 7 percent increase from 14,586 BOE per day in the same period of 2024. The increase reflects the success of the 2025 drilling program and well reactivations completed in the first quarter, which supported four consecutive quarters of record production through the first half of the year. Third quarter production averaged 14,460 BOE per day, inclusive of approximately 300 BOE per day of unplanned downtime, reflecting planned declines in the later half of the year following strong additions earlier in 2025. New production additions were muted in the quarter with 5 gross (0.7 net) non-operated wells in the Cardium being brought on production in Q3 2025 and no new operated wells.
- **Funds flow**¹ totaled \$21.3 million (\$0.58 per diluted share) in the third quarter of 2025. Funds flow for the first nine months of 2025 decreased by \$16.5 million compared to the same period in 2024, primarily due an 11% decrease in realised crude oil prices.
- **Field netback and cash netback**¹ averaged \$20.16 per BOE and \$16.03 per BOE during Q3 2025, respectively, with WTI crude oil prices averaging US\$64.93 per barrel and AECO natural gas prices averaging \$0.63 per mcf during Q3 2025.
- **Production costs** averaged \$16.92 per BOE in the first nine months of 2025 as compared to \$16.71 per BOE in the same period of 2024. The 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**¹ totaled \$53.6 million during the nine months ended September 30, 2025. Of this amount, \$22.7 million was directed toward infrastructure, land and lease acquisitions, and recompletions; the remaining \$30.9 million was allocated to the drilling of fifteen gross (8.4 net) wells, of which twelve gross (5.7 net) wells were completed, equipped, and tied-in. During Q3 2025 \$14.8 million of capital expenditures were primarily attributed to the drilling of a three-well pad in the Charlie Lake and infrastructure expenditures in the Cardium. Two (1.8 net) of the three gross (2.7 net) wells from the recent three-well Charlie Lake pad are expected to be tied-in during the fourth quarter of 2025, with the third anticipated in the first quarter of 2026.
- **Net debt**¹ totaled \$167.8 million as at September 30, 2025, a decrease of \$2.1 million from Q2 2025. At September 30, 2025, the Company had a net debt to EBITDA ratio of 1.4:1.
- **Normal Course Issuer Bid** initiated in April, and during the nine months ended September 30, 2025 the Company purchased 737,700 common shares for cancellation at an average price of \$3.54 per common share.

¹ Non-IFRS measure. See advisories later in this press release.

OPERATIONS UPDATE

Charlie Lake

The Company drilled an additional three gross (2.7 net) wells in the third quarter of 2025. The recent three-well pad was executed with three-mile laterals and increased fracture stimulation intensity as compared to the previously drilled wells in the Charlie Lake. Currently, two of the three wells are in the early stages of cleaning up post completion operations and progressing as planned, with the third well planned to be completed in the first quarter of 2026. Net production from the Charlie Lake asset in Q3 2025 was approximately 1,900 BOE per day.

Montney

The Company's latest Montney well (the "4-28 well") continues to deliver strong results after 12 months, currently producing at rates of approximately 530 BOE per day, including approximately 185 barrels per day of light crude oil, 1.7 mmcf per day of conventional natural gas and 65 barrels per day of natural gas liquids. The 4-28 well has cumulatively produced 87,600 barrels of light crude oil, 680 mmcf of conventional natural gas and 24,400 barrels of natural gas liquids over a twelve-month period. Net production from the Montney

asset in Q3 2025 was approximately 950 BOE per day.

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 is planning to continue delineation of its Montney lands with commencement of drilling operations for a new Montney well in Q4 2025, to be completed and tied-in to existing egress capacity in the region in 2026.

RETURN-OF-CAPITAL

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 the nine months ended September 30, 2025 the Company purchased 737,700 common shares for cancellation at an average price of \$3.54 per common share.

STRENGTHENED FINANCIAL POSITION

On April 30, 2025, the Company renewed and increased its revolving credit facility to \$125 million. The renewed facility features improved terms, including a wider borrowing base, lower interest rate spreads, and the removal of financial covenants, providing enhanced flexibility to support the Company's capital program and return initiatives. The amount drawn under the total Bank Facility at September 30, 2025 was \$26.0 million (December 31, 2024 - \$46.2 million).

RISK MANAGEMENT AND COMMODITY PRICING

To protect future cash flows, Bonterra has secured physical delivery sales and risk management contracts for approximately 43% (net of royalties payable) of its expected crude oil production and 30% (net of royalties payable) of its natural gas production over the next nine months, ending June 30, 2026.

During this period, the Company has secured WTI prices between \$55.00 USD and \$75.50 USD per barrel for 2,169 barrels per day, primarily through costless collar contracts. For natural gas, Bonterra has locked in prices between \$1.75 and \$3.30 per GJ for 11,284 GJ per day, also primarily using costless collars.

In addition, Bonterra has secured WTI pricing of \$60.04 USD per barrel for 500 barrels per day for the final six months of 2026, and natural gas prices between \$3.10 and \$3.30 per GJ for 6,679 GJ per day covering the final six months of 2026 and the first quarter of 2027, through fixed-price contracts.

OUTLOOK

Bonterra is maintaining its previously revised annual production guidance of 15,000 to 15,200 BOE per day and annual capital expenditure guidance of \$65 to \$70 million.

For the remainder of the year, Bonterra plans to continue to focus on free funds flow generation and balance sheet management with the fourth quarter capital program scheduled to drill 1 gross (1.0 net) Montney well and complete, tie-in and bring on production 2 gross (1.8 net) wells in the Charlie Lake. Bonterra plans to enter 2026 with one Montney well and one Charlie Lake well drilled and uncompleted (DUC).

“I am encouraged with the progress made and the successful pivot and integration of our high impact plays in the Charlie Lake and Montney complementing our legacy Cardium asset,” said Patrick Oliver, Bonterra’s President and Chief Executive Officer. “Step change improvement in capital efficiencies have positioned the Company for future growth and free funds flow generation at a wider range of commodity prices.”

Bonterra remains focused on driving production efficiency and maximizing returns, generating free funds flow to support debt repayment, maintaining a debt-neutral position while funding its NCIB, and evaluating strategic acquisition opportunities in its core areas.

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 (formerly Twitter) for ongoing updates and developments.

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Cautionary Statements

This summarized news 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 third quarter report. For the full report, please go to www.bonterraenergy.com.

Non-IFRS and Other Financial Measures

In this 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”, “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 and nine months ended September 30, 2025 reconciliations as outlined below.

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:

Funds Flow

	Three months ended		Nine months ended	
	September	September	September	September
(\$ millions)	30,	30,	30,	30,
	2025	2024	2025	2024
Cash flow from operating activities	8.3	31.5	68.0	86.3
Adjusted for:				
Changes in non-cash working capital	6.1	(2.6)	0.7	(3.1)
Interest expense	(4.1)	(4.4)	(12.6)	(13.5)
Interest paid	7.7	3.1	10.2	12.2
Decommissioning expenditures	3.2	2.4	5.5	5.0
Investment income received	0.1	0.1	0.3	0.3
Proceeds on sale of investments	-	-	-	1.4
Funds flow	21.3	30.1	72.1	88.6

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 and is displayed in the nine-month period ended September 30, 2025, condensed financial statements as follows:

(\$ millions)	Three months ended		Nine months ended	
	September 30, 2025	September 30, 2024	September 30, 2025	September 30, 2024
Comprised of:				
Exploration and evaluation expenditures	0.4	0.2	0.8	0.9
Property, plant and equipment expenditures	14.4	23.9	52.8	77.7
Capital Expenditures	14.8	24.1	53.6	78.6

Net Debt and Net Debt to EBITDA Ratio

Net debt is a non-IFRS financial measure, calculated as long-term subordinated term debt, subordinated debentures, subordinated notes and bank debt plus working capital deficiency (current liabilities less current assets). 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. 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. For more information about net debt or net debt to EBITDA ratio, please refer to Note 10 of the September 30, 2025 condensed financial statements.

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

(\$ millions)	September 30, 2025	December 31, 2024
Bank debt	26.0	46.2
Subordinated term debt	-	35.8
Subordinated debentures	-	55.9
Subordinated notes	131.9	-
Current liabilities	39.9	61.4
Current assets	(30.0)	(32.0)
Net debt	167.8	167.3
Net earnings (loss)	(14.7)	10.2
Adjustments to net earnings (loss) :		
Unrealized loss on risk management contracts	2.1	1.5
Gain on sale of property	(4.5)	-

Deferred consideration	(1.0)	(1.0)
Finance costs	23.2	26.5
Share-based compensation	2.8	2.3
Depletion and depreciation	103.0	97.1
Extinguishment of debt	11.6	-
Current income tax expense (recovery)	(0.5)	5.2
Deferred income tax recovery	(3.3)	(1.5)
EBITDA (trailing twelve months)	118.7	140.3
Net debt to EBITDA ratio	1.4	1.2

Field and Cash Netback

Field netback is a non-IFRS financial measure. 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. 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. 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. 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. 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. 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:

Field and Cash Netback

(\$ millions)	Three months ended		Nine months ended	
	September 30, 2025	September 30, 2024	September 30, 2025	September 30, 2024
Oil and gas sales	55.2	69.2	190.0	210.3
Realized gain on risk management contracts	0.5	1.2	1.4	1.9
Royalties	(7.1)	(10.7)	(25.4)	(30.1)
Production costs	(21.8)	(22.6)	(72.1)	(66.8)
Field Netback	26.8	37.1	93.9	115.3
Office and administration	(1.2)	(0.6)	(4.1)	(3.9)
Employee compensation	(1.7)	(1.9)	(5.3)	(5.3)
Proceeds on sale of investments	-	-	-	1.4
Interest expense less other income	(4.0)	(4.3)	(12.1)	(13.0)
Current income tax	1.4	(0.2)	(0.3)	(5.9)

Cash Netback	21.3	30.1	72.1	88.6
	1,330,29		4,258,77	
Barrel of oil equivalent (BOE)	4	1,409,407	7	3,996,653
Field Netback (\$ per BOE)	20.16	26.25	22.07	28.85
Cash Netback (\$ per BOE)	16.03	21.33	16.92	22.16

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 2025 financial and operating guidance relating to production and capital expenditures; the Company’s 2025 priorities and outlook; exploration and development activities; repayment of indebtedness; plans to continue funding the NCIB; 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.

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.

Numerical Amounts

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.

