Q1 Report
2026

BAYTEX

BAYTEX DELIVERS STRONG FIRST QUARTER 2026 RESULTS; RAISES PRODUCTION GUIDANCE AND NEARLY DOUBLES 3-YEAR GROWTH OUTLOOK; CEO TRANSITION COMPLETE

CALGARY, ALBERTA (May 7, 2026) - Baytex Energy Corp. ("Baytex" or the "Company") (TSX:BTE) (NYSE:BTE) reports its operating and financial results for the three months ended March 31, 2026 (all amounts are in Canadian dollars unless otherwise noted).

"Baytex's strong first quarter results reflect the quality of our Canadian portfolio and the operational discipline of our team," said Chad Lundberg, President and Chief Executive Officer. “Outperformance across our heavy oil portfolio drove production above the high end of guidance, which combined with strengthening returns, underpinned our decision to raise both our 2026 production guidance and three-year growth outlook. As I step into the CEO role, I am confident in the strength of our portfolio and the team. We are committed to technical leadership and disciplined capital allocation as the foundation for long-term value creation."

CEO Transition

- Effective today, Chad Lundberg assumes the position of President and Chief Executive Officer and joins the Board of Directors. Having joined Baytex in 2018, Chad has played a central role in building and optimizing the Company's Canadian asset base. His deep operational expertise and track record of disciplined execution position Baytex well for its next phase of growth as a focused Canadian energy producer.

First Quarter Highlights

- Delivered production of 69,478 boe/d (88% oil and NGL), exceeding the high end of quarterly guidance.
- Generated adjusted funds flow[(1)] of $151 million ($0.20 per basic share) and cash flows from operating activities of $122 million ($0.16 per basic share).
- Repurchased 35.1 million common shares for $174 million, representing 4.6% of shares outstanding.
- Exited the first quarter with net cash[(1)] of $591 million.
- Strong Peavine performance with first 6 wells of 2026 program exceeding initial expectations.
- Drilled seven discrete horizons in the Mannville at Lloydminster.
- Acquired an additional 40 sections of highly prospective lands at Utikuma in the Peace River region.

2026 Guidance

- Increasing production guidance to 69,000 to 71,000 boe/d (up from 67,000 to 69,000 boe/d) with a targeted exit production rate of 71,000 to 72,000 boe/d (up from 69,000 to 70,000 boe/d, previously).
- Targeting 7% annual production growth (up from 3% to 5%, previously) driven by strong operating performance and planned 2H activity.
- Maintaining capital discipline with exploration and development expenditures targeted at high end of guidance range, approximately $625 million (previously $550 to $625 million).
- Incremental spending allocated to heavy oil and the Pembina Duvernay.

3-Year Outlook

- Baytex targets a 15% annual total shareholder return, comprising production growth, dividends, and share buybacks - based on a long-term WTI price of US$70/bbl.
- The updated 3-year outlook targets annual production growth of 6% to 8% (up from 3% to 5%) while maintaining a net cash position throughout the period.
- We intend to advance planning for our Gemini thermal SAGD project with a potential final investment decision in 2027. Gemini is an approved development scheme supporting an initial 5,000 bbl/d first phase, with 44 million barrels of probable reserves at year-end 2025.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.

	Three Months Ended		
	March 31, 2026	December 31, 2025	March 31, 2025
FINANCIAL (thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales - Canada	**$ 452,954**	$ 381,556	$ 454,151
Adjusted funds flow (1)	**151,125**	261,531	463,870
Per share – basic	**0.20**	0.34	0.60
Per share – diluted	**0.20**	0.34	0.60
Free cash flow (2)	**1,705**	76,486	52,529
Per share – basic	**—**	0.10	0.07
Per share – diluted	**—**	0.10	0.07
Cash flows from operating activities	**122,203**	227,657	431,317
Per share – basic	**0.16**	0.30	0.56
Per share – diluted	**0.16**	0.30	0.56
Net (loss) income	**(67,326)**	(856,887)	69,591
Per share – basic	**(0.09)**	(1.12)	0.09
Per share – diluted	**(0.09)**	(1.12)	0.09
Dividends declared	**16,606**	17,268	17,289
Per share	**0.0225**	0.0225	0.0225
Capital Expenditures			
Exploration and development expenditures	**$ 145,012**	$ 174,078	$ 405,097
Acquisitions and (divestitures)	**(4,986)**	(3,006,514)	(1,009)
Total oil and natural gas capital expenditures	**$ 140,026**	$ (2,832,436)	$ 404,088
Net (Cash) Debt			
Credit facilities	**$ —**	$ 1,400	$ 250,284
Long-term notes	**89,507**	95,947	1,977,044
Total debt (3)	**89,507**	97,347	2,227,328
Working capital (surplus) deficiency (2)	**(680,658)**	(863,132)	162,922
Net (cash) debt (1)	**$ (591,151)**	$ (765,785)	$ 2,390,250
Shares Outstanding - basic (thousands)			
Weighted average	**747,156**	768,287	771,443
End of period	**730,561**	765,568	770,039
BENCHMARK PRICES			
Crude oil			
WTI (US$/bbl)	**$ 71.93**	$ 59.14	$ 71.42
Edmonton par ($/bbl)	**93.50**	76.49	95.27
Edmonton par differential to WTI (US$/bbl)	**(3.76)**	(4.30)	(5.03)
WCS heavy oil ($/bbl)	**79.28**	66.88	84.33
WCS differential to WTI (US$/bbl)	**(14.13)**	(11.19)	(12.65)
Natural gas			
NYMEX (US$/MMbtu)	**$ 5.04**	$ 3.55	$ 3.65
AECO ($/Mcf)	**2.49**	2.34	2.02
CAD/USD average exchange rate	**1.3716**	1.3949	1.4350

Notes:

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by International Financial Reporting Standards ("IFRS") and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Calculated in accordance with our credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.

	Three Months Ended		
	March 31, 2026	December 31, 2025	March 31, 2025
OPERATING			
Daily Production			
Light oil and condensate (bbl/d)	**11,835**	12,031	11,775
Heavy oil (bbl/d)	**44,908**	42,628	40,192
NGL (bbl/d)	**4,368**	4,488	3,123
Total liquids (bbl/d)	**61,111**	59,147	55,090
Natural gas (Mcf/d)	**50,205**	48,895	43,743
Total Canada (boe/d) (1)	**69,478**	67,295	62,380
Discontinued operations (boe/d) (1)	**—**	69,792	81,814
Oil equivalent (boe/d) (1)	**69,478**	137,087	144,194
Adjusted Funds Flow (thousands of Canadian dollars)			
Total sales, net of blending and other expense (2)	**$ 377,033**	$ 331,517	$ 381,331
Royalties	**(51,589)**	(43,132)	(59,256)
Operating expense	**(81,244)**	(85,708)	(75,580)
Transportation expense	**(23,134)**	(21,314)	(18,779)
Operating netback - Canada (2)	**$ 221,066**	$ 181,363	$ 227,716
General and administrative expense	**(22,299)**	(16,918)	(18,566)
Net cash interest income (expense)	**2,754**	(36,455)	(43,591)
Realized financial derivatives (loss) gain	**(29,289)**	1,013	(194)
Other (3)	**(20,021)**	(12,789)	(3,353)
Adjusted funds flow - Canada (4)	**$ 152,211**	$ 116,214	$ 162,012
Adjusted funds flow - Discontinued operations (4)	**(1,086)**	145,317	301,858
Adjusted funds flow (4)	**$ 151,125**	$ 261,531	$ 463,870
Adjusted Funds Flow (per boe)			
Total sales, net of blending and other expense (2)	**$ 60.30**	$ 53.55	$ 67.92
Royalties (5)	**(8.25)**	(6.97)	(10.55)
Operating expense (5)	**(12.99)**	(13.84)	(13.46)
Transportation expense (5)	**(3.70)**	(3.44)	(3.34)
Operating netback - Canada (2)	**$ 35.36**	$ 29.30	$ 40.57
General and administrative expense (5)	**(3.57)**	(2.73)	(3.31)
Net cash interest income (expense) (5)	**0.44**	(5.89)	(7.76)
Realized financial derivatives (loss) gain (5)	**(4.68)**	0.16	(0.03)
Other (3)(5)	**(3.20)**	(2.07)	(0.60)
Adjusted funds flow - Canada (4)	**$ 24.35**	$ 18.77	$ 28.87
Adjusted funds flow - Discontinued operations (4)	**—**	22.63	41.00
Adjusted funds flow (4)	**$ 24.17**	$ 20.74	$ 35.74

Notes:

(1) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil 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) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.

(3) Other is comprised of realized foreign exchange gain or loss, cash other income or expense, current income tax expense or recovery and cash share-based compensation. Refer to the Q1/2026 MD&A for further information on these amounts.

(4) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.

(5) Calculated as royalties, operating expense, transportation expense, general and administrative expense, net cash interest income or expense, realized financial derivatives gain or loss, or other, divided by barrels of oil equivalent production volume for the applicable period for continuing operations.

Our Strategic Priorities

Baytex is a focused Canadian producer with a high-quality asset base centered on heavy oil operations and an attractive position in the Duvernay. We are committed to technical leadership and disciplined capital allocation to create value, while maintaining a strong, flexible balance sheet. Our strategy is anchored by three key priorities:

1. *Target 15% Annual Total Shareholder return*

   We intend to target an approximate 15% annual total shareholder return at a mid-cycle WTI price of US$70/bbl. Total shareholder returns comprises a combination of production growth, dividends, and share buybacks.

2. *Building a Culture of Disciplined Growth and Long-Term Value*

   With significant inventory depth and optionality across our portfolio, we are committed to delivering disciplined growth while investing in long-term infrastructure and exploration that supports future value creation. We are targeting annual production growth of 6% to 8% at a mid-cycle WTI price of US$70/bbl. At the same time, we are focused on improving our cash cost structure and capital efficiencies, with a long-term sustaining break-even target of under US$50/bbl WTI - reinforcing our resilience across the commodity cycle.

3. *Achieve Full-Scale Development in the Duvernay and Advance Heavy Oil Opportunity Set*

   Disciplined investment across our core assets underpins long-term value creation. In the Duvernay, we have assembled 91,500 net acres and identified approximately 210 drilling locations. Production is expected to increase 35% to average approximately 11,000 boe/d in 2026, with a target year-end exit rate of 14,000 to 15,000 boe/d.

   Our heavy oil assets comprise 750,000 net acres and approximately 1,100 drilling locations, supporting approximately 12 years of drilling at our current pace of development. Our 2026 program will see increased exploration activity, including stratigraphic tests, step-out wells and 3-D seismic, to expand our development inventory and test new play concepts across our extensive heavy oil fairway.

   We are also advancing two waterflood pilot projects at Peavine, combining the capital efficiency of multi-lateral primary development with the potential for enhanced recovery and moderated decline rates. First injection for the water flood pilots is scheduled for June 2026.

2026 Outlook: Accelerating 2H Activity; Production Guidance Increased

Our 2026 budget, released in December 2025 targeted annual production of 67,000 to 69,000 boe/d, representing 3% to 5% organic growth, with E&D expenditures of $550 to $625 million. This plan was developed with significant optionality to support accelerated growth in a more constructive pricing environment.

Based on strong operating performance to-date and planned 2H activity, we now expect 7% annual production growth in 2026. Our 2026 production guidance increases to 69,000 to 71,000 boe/d with a targeted 2026 exit production rate of 71,000 to 72,000 boe/d (up from 69,000 to 70,000 boe/d).

In today's stronger pricing environment - with a two-year forward strip of approximately US$75/bbl - we are maintaining capital discipline. We are now targeting exploration and development expenditures at the high end of our guidance range, at approximately $625 million. Incremental spending will be directed to our heavy oil portfolio and the Duvernay.

In heavy oil, we plan to bring approximately 100 net wells onstream in 2026 (up from 91 net wells, previously). In the Duvernay, we expect to drill 17 wells (up from 12 wells) and bring 13 wells onstream. The remaining four wells are expected to be completed and brought onstream in the first quarter of 2027.

Updated Three-Year Outlook Demonstrates Strength of Portfolio

We have updated our three-year outlook (2026 to 2028) based on a mid-cycle WTI price of US$70/bbl. We now expect to deliver 6% to 8% annual production growth (up from 3% to 5%) while maintaining a net cash position throughout the period.

In the Duvernay, we are transitioning to a one-rig drilling program, targeting 30% annual production growth and an 80% increase in field-level operating income by 2028. The three-year infrastructure build-out is expected to support production of 20,000-25,000 bbl/d by 2029-2030, with ongoing improvements in capital efficiency.

The heavy oil portfolio is expected to grow modestly and deliver meaningful free cash flow. Baytex will continue to prioritize Mannville stack development, exploration and enhanced oil recovery.

Beyond our three-year outlook, the Gemini thermal SAGD project in northeast Alberta represents a significant source of long-term value. Gemini is an approved development scheme supporting an initial 5,000 bbl/d first phase development, with 44 million barrels of probable reserves at year-end 2025. Over the next twelve months, we intend to advance planning toward a potential final investment decision in 2027 - adding meaningful optionality to our inventory.

Throughout the plan period, Baytex remains committed to meaningful shareholder returns, with excess free cash flow available for incremental investment and/or enhanced returns, including buybacks and dividends.

First Quarter 2026 Results

Q1 Production Exceeds Guidance

Baytex delivered strong first quarter results highlighted by outperformance across our heavy oil portfolio. Production averaged 69,478 boe/d (88% oil and NGL), exceeding the high end of our quarterly guidance range of 68,000 to 69,000 boe/d. Exploration and development expenditures totaled $145 million, consistent with our full-year plan, and we brought 54 (52.7 net) wells onstream.

Adjusted funds flow(1) was $151 million ($0.20 per basic share). We generated a net loss of $67 million ($0.09 per basic share), due largely to unrealized financial derivatives losses.

Accelerated Shareholder Returns: Repurchased 5.9% of Shares to-Date

During the first quarter, we repurchased 35.1 million common shares for $174 million, representing 4.6% of our shares outstanding, at an average price of $4.96 per share. Through May 6, 2026, we repurchased 45.1 million common shares for $229 million, representing 5.9% of our shares outstanding, at an average price of $5.07 per share, pursuant to our current normal course issuer bid.

We exited the first quarter with net cash(1) of $591 million.

Strong Peavine Results; Mannville Heavy Oil Success; New Exploration Lands Added at Peace River

First quarter operating results reflect continued performance at Peavine, Peace River, and across the broader Mannville group in Lloydminster. We brought onstream 25.7 net wells during the quarter: 6 Clearwater wells at Peavine, 3 wells at Peace River and 16.7 net wells at Lloydminster.

At Peavine, the first six wells of our 2026 program generated an average 30-day initial production rate of 680 bbl/d per well, significantly outperforming expectations.

At Lloydminster, we stepped up activity with 3-rigs running during the quarter. We successfully targeted seven discrete horizons in the Mannville through a combination of multi-lateral and circulation string horizontal wells.

We continue to build on our heavy oil expertise and enhance our prospect inventory. In the first quarter, we acquired an additional 40 sections of highly prospective lands at Utikuma in the Peace River region, bringing our land holdings in the area to 109 sections. We recently completed a 21-square-mile seismic survey covering 20% of our land base, and following interpretation, we could drill our first exploration test well in early 2027.

Duvernay Drilling Program Underway; First Wells of 2026 Program Expected Onstream in June

In the Duvernay, we drilled our first four wells during the first quarter, with completion operations now underway. In total, we expect to bring 13 wells onstream in 2026 with the remaining nine wells onstream during Q3 and Q4.

Executive Appointments

Baytex has made the following executive appointments, effective May 7, 2026, reflecting the company's commitment to long-term succession planning and operational leadership.

Kendall Arthur has been appointed Chief Operating Officer, having previously served as Senior Vice President and General Manager, Heavy Oil. Adrian Blazevic has been appointed Vice President, Heavy Oil, having previously served as Manager of Geoscience. Kendall and Adrian have been instrumental in the growth of our Canadian operations and are central to our long-term leadership plan.

Brian Ector, Senior Vice President Capital Markets and Investor Relations, will be retiring on July 31, 2026. Over his 17 years with Baytex, Brian has been a trusted partner to the investment community and valued member of the leadership team. We thank him for his significant contributions to the Company.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.

Quarterly Dividend

The Board of Directors has declared a quarterly cash dividend of $0.0225 per share, payable July 2, 2026 to shareholders of record on June 15, 2026.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three months ended March 31, 2026, and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR+ at www.sedarplus.ca and EDGAR at www.sec.gov/edgar.shtml.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "believe", "continue", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to but not limited to: guidance for 2026 production, production growth rate, exit production rate, exportation and development expenditures and that incremental spending will be allocated to heavy oil and the Duvernay; with respect to our 3-year outlook: a targeted annual total shareholder return of 15% at US$70 WTI, annual production growth of 6% to 8% while maintaining a net cash position and the potential for a final investment decision on our Gemini project in 2027; we are committed to technical leadership, disciplined capital allocation, a strong flexible balance sheet, disciplined growth while investing in long-term infrastructure and exploration that supports future value creation; focused on improving cash cost structure and capital efficiencies and a long-term sustaining break-even target of under US$50/bbl WTI; our drilling and development plans for the Duvernay (including expected production growth and year-end exit production rate) and heavy oil (including supported duration of drilling inventory and 2026 program activities); the number of wells to be drilled and brought on stream in heavy oil and the Duvernay in 2026; the three year outlook, including that Duvernay targets a 30% annual production growth rate, an 80% increase in field-level operating income and an infrastructure build out that supports production of 20,000-25,000 bbl/d and that excess cash flow available will be for incremental investment and /or enhanced returns; that we could drill a Utikima exploration well in early 2027; the number and timing for Duvernay wells to be brought onstream in 2026; and Mr. Ector's expected retirement date. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy crude oil prices; well production rates and reserve volumes; success obtained drilling new wells; the duration and impact of tariffs that are currently in effect on goods exported from or imported into Canada, and that other than the tariffs that are currently in effect, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, reenacts tariffs that are currently suspended, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; operating costs; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; our ability to successfully market oil and natural gas; that we will have sufficient financial resources in the future to pursue our development plans and provide shareholder returns; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the risk of an extended period of low oil and natural gas prices (including as a result of tariffs); risks associated with our ability to develop our properties and add reserves; that we may not achieve the expected benefits of acquisitions and we may sell assets below their carrying value; the availability and cost of capital or borrowing; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; the impact of an energy transition on demand for petroleum productions; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; risks associated with large projects; risks associated with higher a higher concentration of activity and tighter drilling spacing; costs to develop and operate our properties; current or future controls, legislation or regulations; restrictions on or access *to water or other fluids; public perception and its influence on the regulatory regime; new regulations on hydraulic fracturing; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy crude oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; adverse results of litigation; that our Credit Facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with expansion into new activities; the impact of Indigenous claims; risks of counterparty default; impact of geopolitical risk and conflicts; loss of foreign private issuer status; conflicts of interest between the Company and its directors and officers; variability of share buybacks and dividends; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.*

Any decision to pay dividends on the Common Shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith or acquire Common Shares pursuant to a share buyback (including through the current Normal Course Issuer Bid will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, the Company's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions (including covenants contained in the agreements governing any indebtedness that the Company has incurred or may incur in the future, including the terms of the Credit Facilities and satisfaction of the solvency tests imposed on the Company under applicable corporate law. There can be no assurance of the number of Common Shares that the Company will acquire pursuant to a share buyback, if any, in the future. Further, the payment of dividends to shareholders is not assured or guaranteed and dividends may be reduced or suspended entirely.

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2025, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings. The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

This press release contains information that may be considered a financial outlook under applicable securities laws about the Company's potential financial position, including, but not limited to: our 2026 guidance for development expenditures; that we can maintain a net cash position and the expected field-level operating income growth in Duvernay during our 3-year outlook period; and our intentions regarding excess free cash flow; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Company and the resulting financial results will vary from the amounts set forth in this press release and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Company undertakes no obligation to update such financial outlook, whether as a result of new information, future events or otherwise. The financial outlook contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about the Company's potential future business operations. Readers are cautioned that the financial outlook contained in this press release is not conclusive and is subject to change.

All amounts in this press release are stated in Canadian dollars unless otherwise specified.

Specified Financial Measures

In this press release, we refer to certain financial measures (such as total sales, net of blending and other expense, operating netback, free cash flow, and working capital (surplus deficiency which do not have any standardized meaning prescribed by IFRS. While these measures are commonly used in the oil and gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. This press release also contains the terms "adjusted funds flow" and "net (cash debt" which are considered capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

Non-GAAP Financial Measures

Total sales, net of blending and other expense - Canada

Total sales, net of blending and other expense represents the revenues realized from produced volumes during a period. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense for Canada. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

Operating netback - Canada

Operating netback is used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense for Canada.

The following table reconciles operating netback to petroleum and natural gas sales for Canada.

	Three Months Ended		
($ thousands)	**March 31, 2026**	December 31, 2025	March 31, 2025
Petroleum and natural gas sales	**$ 452,954**	$ 381,556	$ 454,151
Blending and other expense	**(75,921)**	(50,039)	(72,820)
Total sales, net of blending and other expense	**$ 377,033**	$ 331,517	$ 381,331
Royalties	**(51,589)**	(43,132)	(59,256)
Operating expense	**(81,244)**	(85,708)	(75,580)
Transportation expense	**(23,134)**	(21,314)	(18,779)
Operating netback - Canada	**$ 221,066**	$ 181,363	$ 227,716

Free cash flow

We use free cash flow to evaluate our financial performance and to assess the cash available for debt repayment, common share repurchases, dividends and acquisition opportunities. Free cash flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, additions to exploration and evaluation assets, additions to oil and gas properties, payments on lease obligations, and transaction costs.

Free cash flow is reconciled to cash flows from operating activities in the following table.

	Three Months Ended		
($ thousands)	**March 31, 2026**	December 31, 2025	March 31, 2025
Cash flows from operating activities	**$ 122,203**	$ 227,657	$ 431,317
Change in non-cash working capital	**26,303**	(226)	29,034
Additions to exploration and evaluation assets	**(1,737)**	—	—
Additions to oil and gas properties	**(143,275)**	(174,078)	(405,097)
Payments on lease obligations	**(1,789)**	(3,250)	(2,725)
Transaction costs	**—**	26,383	—
Free cash flow	**$ 1,705**	$ 76,486	$ 52,529

Working capital (surplus) deficiency

Working capital (surplus) deficiency is calculated as cash, trade receivables, and prepaids and other assets net of trade payables, share-based compensation liability, dividends payable, and other long-term liabilities. Working capital (surplus) deficiency is used by management to measure the Company's liquidity. On March 31, 2026, the Company had $745.6 million of available credit facility capacity to cover any working capital deficiencies.

The following table summarizes the calculation of working capital (surplus) deficiency.

	As at		
($ thousands)	**March 31, 2026**	December 31, 2025	March 31, 2025
Cash	**$ (757,869)**	$ (953,113)	$ (5,966)
Trade receivables	**(194,985)**	(135,230)	(391,905)
Prepaids and other assets	**(59,091)**	(63,232)	(72,045)
Inventory	**(14,174)**	—	—
Trade payables	**303,107**	236,373	582,053
Share-based compensation liability	**25,748**	34,802	12,602
Dividends payable	**16,606**	17,268	17,334
Other long-term liabilities	**—**	—	20,849
Working capital (surplus) deficiency	**$ (680,658)**	$ (863,132)	$ 162,922

Non-GAAP Financial Ratios

Total sales, net of blending and other expense per boe

Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense (a non-GAAP financial measure divided by barrels of oil equivalent production volume for the applicable period for Canada.

Operating netback per boe

Operating netback per boe is equal to operating netback (a non-GAAP financial measure divided by barrels of oil equivalent sales volume for the applicable period for Canada and is used to assess our operating performance on a unit of production basis.

Capital Management Measures

Net (cash) debt

We use net (cash debt to monitor our current financial position and to evaluate existing sources of liquidity. We also use net (cash debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net (cash debt is comprised of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade payables, share-based compensation liability, dividends payable, other long-term liabilities, cash, trade receivables, and prepaids and other assets.

The following table summarizes our calculation of net (cash debt.

	As at		
($ thousands)	**March 31, 2026**	December 31, 2025	March 31, 2025
Credit facilities	**$ —**	$ 1,138	$ 234,683
Unamortized debt issuance costs - Credit facilities (1)	**—**	262	15,601
Long-term notes	**87,598**	93,834	1,930,809
Unamortized debt issuance costs - Long-term notes (1)	**1,909**	2,113	46,235
Trade payables	**303,107**	236,373	582,053
Share-based compensation liability	**25,748**	34,802	12,602
Dividends payable	**16,606**	17,268	17,334
Other long-term liabilities	**—**	—	20,849
Cash	**(757,869)**	(953,113)	(5,966)
Trade receivables	**(194,985)**	(135,230)	(391,905)
Prepaids and other assets	**(59,091)**	(63,232)	(72,045)
Inventory	**(14,174)**	—	—
Net (cash) debt	**$ (591,151)**	$ (765,785)	$ 2,390,250

(1) Unamortized debt issuance costs were obtained from the Long-term Notes and Credit Facilities notes within the consolidated financial statements for the respective period end.

Adjusted funds flow

Adjusted funds flow is used to monitor operating performance and our ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, asset retirement obligations settled, and transaction costs during the applicable period.

Adjusted funds flow is reconciled to amounts disclosed in the primary financial statements in the following table.

	Three Months Ended		
($ thousands)	**March 31, 2026**	December 31, 2025	March 31, 2025
Cash flow from operating activities	**$ 122,203**	$ 227,657	$ 431,317
Change in non-cash working capital	**26,303**	(226)	29,034
Asset retirement obligations settled	**2,619**	7,717	3,519
Transaction costs	**—**	26,383	—
Adjusted funds flow	**$ 151,125**	$ 261,531	$ 463,870

Advisory Regarding Oil and Gas Information

Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

References herein to average 30-day initial production 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 aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

This press release discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. In the Duvernay, Baytex's net drilling locations include 58 proved and 11 probable locations as at December 31, 2025 and 141 unbooked locations. In the Viking, Baytex's net drilling locations include 457 proved and 196 probable locations as at December 31, 2025 and 263 unbooked locations. In the heavy oil business unit, Baytex's net drilling locations include 160 proved and 167 probable locations as at December 31, 2025 and 773 unbooked locations.

Throughout this press release, "oil and NGL" refers to heavy crude oil, bitumen, light and medium crude oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three months ended March 31, 2026 and 2025. The NI 51-101 product types are included as follows: "Heavy Crude Oil" - heavy crude oil and bitumen, "Light and Medium Crude Oil" - light and medium crude oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas.

	Three Months Ended March 31, 2026					Three Months Ended March 31, 2025				
	Heavy Crude Oil (bbl/d)	Light and Medium Crude Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Crude Oil (bbl/d)	Light and Medium Crude Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	8,988	5	20	8,597	10,445	10,212	11	18	9,622	11,845
Lloydminster	15,477	9	—	1,140	15,676	11,349	13	—	1,190	11,560
Peavine	19,757	—	—	—	19,757	17,714	—	—	—	17,714
Remaining Properties	651	4	—	681	768	801	1	—	642	909
Canada - Light										
Viking	27	8,059	262	9,917	10,001	111	8,959	153	10,318	10,943
Duvernay	—	3,409	3,245	12,609	8,756	—	2,404	2,221	6,704	5,742
Remaining Properties	8	349	841	17,261	4,075	5	387	731	15,267	3,667
Total Canada	44,908	11,835	4,368	50,205	69,478	40,192	11,775	3,123	43,743	62,380
United States										
Eagle Ford	—	—	—	—	—	—	50,560	15,923	91,988	81,814
Total	44,908	11,835	4,368	50,205	69,478	40,192	62,335	19,046	135,731	144,194

Baytex Energy Corp.

Baytex Energy Corp. is a Calgary-based energy company committed to driving shareholder value through disciplined execution. The Company operates in the Western Canadian Sedimentary Basin, featuring the Pembina Duvernay and heavy oil plays in Alberta and Saskatchewan. Baytex's common shares trade on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE.

For further information about Baytex, please visit our website at www.baytexenergy.com or contact:

Brian Ector, Senior Vice President, Capital Markets & Investor Relations

Toll Free Number: 1-800-524-5521
Email: investor@baytexenergy.com

Baytex Energy Corp.
Management's Discussion and Analysis
For the three months ended March 31, 2026 and 2025
Dated May 7, 2026

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three months ended March 31, 2026. This information is provided as of May 7, 2026. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three months ended March 31, 2026 ("Q1/2026") have been compared with the results for the three months ended March 31, 2025 ("Q1/2025"). This MD&A should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements ("consolidated financial statements") for the three months ended March 31, 2026, its audited comparative consolidated financial statements for the years ended December 31, 2025 and 2024, together with the accompanying notes, and its Annual Information Form ("AIF") for the year ended December 31, 2025. These documents and additional information about Baytex are accessible on the SEDAR+ website at www.sedarplus.ca and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements along with certain measures which do not have any standardized meaning in accordance with International Financial Reporting Standards ("IFRS") as prescribed by the International Accounting Standards Board. The terms "operating netback", "free cash flow", "average royalty rate", "heavy oil, net of blending and other expense" and "total sales, net of blending and other expense" are specified financial measures that do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. This MD&A also contains the terms "adjusted funds flow" and "net cash" which are capital management measures. Refer to our advisory on forward-looking information and statements and a summary of our specified financial measures at the end of the MD&A.

BAYTEX ENERGY CORP.

Baytex Energy Corp. is a Canadian oil and natural gas company based in Calgary, Alberta. Baytex has oil and natural gas assets in Western Canada primarily comprised of Viking and Duvernay light oil assets along with heavy oil assets in Peace River and Lloydminster.

PRESENTATION OF CONTINUING AND DISCONTINUED OPERATIONS

In Q4/2025, we completed the disposition of the operated and non-operated Eagle Ford assets which comprised the U.S. operating segment. This operating segment represented a geographical area of our operations and its results have been classified as discontinued operations. The financial results for the three months ended March 31, 2026 and March 31, 2025 are disaggregated between continuing and discontinued operations in the table below.

In this MD&A, references to "Canada", "Canadian operations" and similar terms refer to the continuing operations of Baytex Energy Corp. and references to "U.S. operations", "Eagle Ford" and similar terms refer to the discontinued operations.

	Three Months Ended March 31					
	2026			2025		
	Continuing	**Discontinued**	**Total**	Continuing	Discontinued	Total
Revenue, net of royalties						
Petroleum and natural gas sales	**$ 452,954**	**$ —**	**$ 452,954**	$ 454,151	$ 544,979	$ 999,130
Royalties	**(51,589)**	**—**	**(51,589)**	(59,256)	(148,681)	(207,937)
	401,365	**—**	**401,365**	394,895	396,298	791,193
Expenses						
Operating	**81,244**	**—**	**81,244**	75,580	72,123	147,703
Transportation	**23,134**	**—**	**23,134**	18,779	11,733	30,512
Blending and other	**75,921**	**—**	**75,921**	72,820	—	72,820
General and administrative	**22,299**	**—**	**22,299**	18,566	7,040	25,606
Exploration and evaluation	**665**	**—**	**665**	107	—	107
Depletion and depreciation	**123,690**	**—**	**123,690**	116,743	203,180	319,923
Share-based compensation	**22,870**	**—**	**22,870**	413	350	763
Net financing and interest expense	**3,097**	**—**	**3,097**	50,567	4,679	55,246
Financial derivatives loss	**150,756**	**—**	**150,756**	49,619	—	49,619
Foreign exchange loss (gain)	**1,934**	**—**	**1,934**	(3,878)	—	(3,878)
(Gain) loss on dispositions	**(2,017)**	**(13,439)**	**(15,456)**	1,229	—	1,229
Other expense (income)	**1,704**	**—**	**1,704**	2,396	(1,207)	1,189
	505,297	**(13,439)**	**491,858**	402,941	297,898	700,839
Net (loss) income before income taxes	**(103,932)**	**13,439**	**(90,493)**	(8,046)	98,400	90,354
Income taxes						
Current income tax expense	**—**	**1,086**	**1,086**	947	1,205	2,152
Deferred income tax (recovery) expense	**(24,253)**	**—**	**(24,253)**	8,362	10,249	18,611
	(24,253)	**1,086**	**(23,167)**	9,309	11,454	20,763
Net (loss) income	**$ (79,679)**	**$ 12,353**	**$ (67,326)**	$ (17,355)	$ 86,946	$ 69,591

FIRST QUARTER HIGHLIGHTS

Baytex delivered strong operating and financial results in Q1/2026. Production of 69,478 boe/d exceeded the high end of our guidance range of 67,000 - 69,000 boe/d driven by outperformance from our heavy oil assets. Exploration and development expenditures of $145.0 million for Q1/2026 were consistent with our full-year plan and were focused on our heavy oil and Duvernay development programs. We remain committed to shareholder returns and completed $174.3 million of share repurchases during Q1/2026.

We invested $145.0 million and generated production of 69,478 boe/d in Q1/2026 compared to exploration and development expenditures of $184.3 million and production of 62,380 boe/d in Q1/2025. Production for Q1/2026 was 11% higher compared to Q1/2025 which reflects strong well performance and the efficiency of our Duvernay and heavy oil development programs. Exploration and development expenditures of $145.0 million reflect our active heavy oil development program with 25.7 net wells brought on production during the quarter. Exploration and development expenditures for Q1/2026 also includes drilling of the first four wells of our 2026 Duvernay development program with completion operations now underway.

In March 2026, oil prices increased sharply and have remained volatile due to the conflict in Iran and related supply disruptions. The WTI benchmark price averaged US$91.00/bbl in March which resulted in an average of US$71.93/bbl for Q1/2026 compared to US$71.42/bbl for Q1/2025. Our financial results for Q1/2026 reflect our strong operating performance and volatile benchmark oil prices which resulted in adjusted funds flow(1) of $152.2 million and cash flows from operating activities of $122.2 million from continuing operations compared to Q1/2025 when we generated adjusted funds flow of $162.0 million and cash flows from operating activities of $155.1 million from continuing operations.

Net cash(1) was $591.2 million at March 31, 2026 compared to $765.8 million at December 31, 2025 which reflects $190.9 million of shareholder returns including share buybacks and the quarterly dividend.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

GUIDANCE

Based on strong operating performance to-date and planned activity for the remainder of the year we have revised our 2026 production guidance to 69,000 - 71,000 boe/d. Additional heavy oil and Duvernay development in the second half of 2026 will result in exploration and development expenditures of approximately $625 million which is at the high end of our annual guidance range.

The following table compares our 2026 revised annual guidance to our previously announced guidance and Q1/2026 results.

	2026 Annual Guidance (1)	Revised Annual Guidance	Q1/2026 Results
Exploration and development expenditures	$550 - $625 million	~ $625 million	$145.0 million
Production (boe/d)	67,000 - 69,000	69,000 - 71,000	69,478
Expenses:			
Average royalty rate (2)	15%	No change	13.7 %
Operating (3)	$13.75 - $14.25/boe	No change	$12.99/boe
Transportation (3)	$3.40 - $3.60/boe	No change	$3.70/boe
Leasing expenditures	$7 million	No change	$1.8 million
Asset retirement obligations settled	$20 million	No change	$2.6 million

(1) As announced on December 22, 2025.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Refer to the Operating Expense and Transportation Expense sections of this MD&A for description of the composition of these measures.

RESULTS OF OPERATIONS

Production

	Three Months Ended March 31		
	2026	2025	Change
Daily Production			
Liquids (bbl/d)			
Light oil and condensate	**11,835**	11,775	1%
Heavy oil	**44,908**	40,192	12%
Natural Gas Liquids (NGL)	**4,368**	3,123	40%
Total liquids (bbl/d)	**61,111**	55,090	11%
Natural gas (mcf/d)	**50,205**	43,743	15%
Daily production (boe/d) - continuing operations	**69,478**	62,380	11%
Daily production (boe/d) - discontinued operations	**—**	81,814	(100)%
Total production (boe/d)	**69,478**	144,194	(52)%
Production Mix - continuing operations			
Light oil and condensate	**17 %**	19 %	(2)%
Heavy oil	**65 %**	64 %	1 %
NGL	**6 %**	5 %	1 %
Natural gas	**12 %**	12 %	— %

Production from continuing operations of 69,478 boe/d for Q1/2026 increased 11% compared to 62,380 boe/d for Q1/2025 with strong performance from both our heavy oil and Duvernay development programs over the last year. Production of 69,478 boe/d for Q1/2026 is consistent with our revised annual guidance range of 69,000 - 71,000 boe/d for 2026.

COMMODITY PRICES

The prices received for our crude oil and natural gas production directly impact our earnings, free cash flow and our financial position.

Benchmark Prices

	Three Months Ended March 31		
	2026	2025	Change
WTI oil (US$/bbl) (1)	**71.93**	71.42	0.51
Edmonton par oil ($/bbl) (2)	**93.50**	95.27	(1.77)
Edmonton par oil differential to WTI (US$/bbl)	**(3.76)**	(5.03)	1.27
WCS heavy oil ($/bbl) (3)	**79.28**	84.33	(5.05)
WCS heavy oil differential to WTI (US$/bbl)	**(14.13)**	(12.65)	(1.48)
AECO 7A natural gas price ($/mcf) (4)	**2.49**	2.02	0.47
AECO 5A natural gas price ($/mcf) (5)	**2.01**	2.19	(0.18)
CAD/USD average exchange rate	**1.3716**	1.4350	(0.0634)

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) Edmonton par refers to the average posting price for the benchmark MSW crude oil.
(3) WCS refers to the average posting price for the benchmark WCS heavy oil.
(4) AECO 7A refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(5) AECO 5A refers to the AECO arithmetic average daily index price published by the CGPR.

Crude Oil

In March 2026, oil prices increased sharply and have remained volatile due to the conflict in Iran and related supply disruptions. The WTI benchmark price averaged US$91.00/bbl in March which resulted in an average of US$71.93/bbl for Q1/2026 compared to US$71.42/bbl for Q1/2025.

Prices for Canadian oil trade at a discount to WTI due to limited egress to diversified markets and the cost of transportation from Western Canada. Differentials for Canadian oil prices relative to WTI fluctuate from period to period based on production and inventory levels in Western Canada.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $93.50/bbl during Q1/2026 compared to $95.27/bbl during Q1/2025. Increased demand for light oil from Canada resulted in Edmonton par trading at a discount to WTI of US$3.76/bbl for Q1/2026 which was narrower compared to US$5.03/bbl for Q1/2025.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS benchmark for Q1/2026 averaged $79.28/bbl compared to $84.33/bbl for Q1/2025. The WCS heavy oil differential to WTI was US$14.13/bbl in Q1/2026 which was wider compared to US$12.65/bbl for Q1/2025 due to higher heavy oil production in Western Canada.

Natural Gas

We compare our natural gas pricing to the AECO 7A benchmark which averaged $2.49/mcf during Q1/2026 compared to $2.02/mcf for Q1/2025. Natural gas prices in Canada remain low due to increasing production combined with egress constraints and slow ramp-up of LNG related demand.

Average Realized Sales Prices

	Three Months Ended March 31		
	2026	2025	Change
Light oil and condensate ($/bbl) [(1)]	**$ 83.55**	$ 93.86	$ (10.31)
Heavy oil, net of blending and other expense ($/bbl) [(2)]	**67.01**	73.51	(6.50)
NGL ($/bbl) [(1)]	**21.77**	28.07	(6.30)
Natural gas ($/mcf) [(1)]	**1.92**	2.05	(0.13)
Total sales, net of blending and other expense ($/boe) [(2)] - continuing operations	**$ 60.30**	$ 67.92	$ (7.62)
Total sales ($/boe) - discontinued operations	**—**	74.01	(74.01)
Total sales, net of blending and other expense ($/boe) [(2)]	**$ 60.30**	$ 71.38	$ (11.08)

(1) Calculated as light oil and condensate or NGL sales divided by barrels of oil equivalent production volume for the applicable period, or natural gas sales divided by the production volume in Mcf for the applicable period for continuing operations.

(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Our total sales, net of blending and other expense per boe for continuing operations was $60.30/boe for Q1/2026 compared to $67.92/boe for Q1/2025. The decrease primarily reflects lower realized prices for our oil and NGL relative to Q1/2025. Although benchmark prices strengthened in March 2026, the quarter as a whole was affected by lower realized pricing earlier in the period and the timing of sales relative to the March price increase.

Our realized light oil and condensate price for continuing operations represents a discount to the Edmonton par price of $9.95/bbl for Q1/2026 compared to a discount of $1.41/bbl in Q1/2025. The wider discount in Q1/2026 reflects the timing of production during the period along with a sharp increase in benchmark oil prices during March 2026.

Our realized heavy oil price, net of blending and other expense for continuing operations was lower in Q1/2026 compared to the same period of 2025 which reflects the decrease in WCS benchmark pricing. Our realized pricing for Q1/2026 represents a discount to the WCS benchmark of $12.27/bbl compared to $10.82/bbl for the same period of 2025.

Our realized NGL price as a percentage of WTI varies based on the product mix of our NGL volumes and changes in the market prices for the underlying products. Expressed in Canadian dollars, our realized NGL price for continuing operations was 22% of WTI in Q1/2026 compared to 27% of WTI in Q1/2025, reflecting higher sales volumes of propane during Q1/2026 relative to Q1/2025.

We compare our Canadian realized natural gas price to the AECO benchmark price. A portion of our natural gas sales is based on the daily index prices which fluctuate independently from the associated monthly index prices. Our realized natural gas price for continuing operations of $1.92/mcf for Q1/2026 was lower than $2.05/mcf for Q1/2025.

PETROLEUM AND NATURAL GAS SALES

	Three Months Ended March 31		
($ thousands)	**2026**	2025	Change
Oil sales			
Light oil and condensate	**$ 88,993**	$ 99,469	$ (10,476)
Heavy oil	**346,737**	338,711	8,026
NGL	**8,560**	7,888	672
Total oil sales	**444,290**	446,068	(1,778)
Natural gas sales	**8,664**	8,083	581
Total petroleum and natural gas sales	**452,954**	454,151	(1,197)
Blending and other expense	**(75,921)**	(72,820)	(3,101)
Total sales, net of blending and other expense [(1)] - continuing operations	**$ 377,033**	$ 381,331	$ (4,298)
Total sales - discontinued operations	**—**	544,979	(544,979)
Total sales, net of blending and other expense [(1)]	**$ 377,033**	$ 926,310	$ (549,277)

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

Total sales, net of blending and other expense for continuing operations was $377.0 million for Q1/2026 compared to $381.3 million for Q1/2025. The decrease in total sales, net of blending and other expense reflects lower realized pricing partially offset by higher production in Q1/2026. The decrease in our realized pricing for Q1/2026 relative to Q1/2025 resulted in a $47.7 million decrease in total sales, net of blending and other expense, partially offset by higher production which contributed to a $43.4 million increase in total sales, net of blending and other expense.

ROYALTIES

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction.

The following table summarizes our royalties and royalty rates for the three months ended March 31, 2026 and 2025.

	Three Months Ended March 31		
($ thousands except for % and per boe)	**2026**	2025	Change
Royalties - continuing operations	**$ 51,589**	$ 59,256	$ (7,667)
Royalties - discontinued operations	**—**	148,681	(148,681)
Total royalties	**$ 51,589**	$ 207,937	$ (156,348)
Average royalty rate [(1)] - continuing operations	**13.7 %**	15.5 %	(1.8)%
Average royalty rate [(1)] - discontinued operations	**— %**	27.3 %	(27.3)%
Total average royalty rate [(1)]	**13.7 %**	22.4 %	(8.7)%
Royalties per boe [(3)] - continuing operations	**$ 8.25**	$ 10.55	$ (2.30)
Royalties per boe [(3)] - discontinued operations	**$ —**	$ 20.19	$ (20.19)
Total royalties per boe [(3)]	**$ 8.25**	$ 16.02	$ (7.77)

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

(2) Royalties per boe is calculated as royalties divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.

Royalties for continuing operations were $51.6 million or 13.7% of total sales, net of blending and other expense for Q1/2026 compared to $59.3 million or 15.5% for Q1/2025. Total royalty expense was lower for Q1/2026 due to lower total sales, net of blending and other expense, relative to Q1/2025. Our average royalty rate of 13.7% for Q1/2026 is slightly below our annual guidance of approximately 15% for 2026.

OPERATING EXPENSE

	Three Months Ended March 31		
($ thousands except for per boe)	**2026**	2025	Change
Operating expense - continuing operations	**$ 81,244**	$ 75,580	$ 5,664
Operating expense - discontinued operations	**—**	72,123	(72,123)
Total operating expense	**$ 81,244**	$ 147,703	$ (66,459)
Operating expense per boe (1) - continuing operations	**$ 12.99**	$ 13.46	$ (0.47)
Operating expense per boe (1) - discontinued operations	**$ —**	$ 9.79	$ (9.79)
Total operating expense per boe (1)	**$ 12.99**	$ 11.38	$ 1.61

(1) Operating expense per boe is calculated as operating expense divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.

Operating expense for continuing operations was $81.2 million ($12.99/boe) for Q1/2026 compared to $75.6 million ($13.46/boe) for Q1/2025. Operating expense for continuing operations for Q1/2026 increased compared to Q1/2025 due to increased production over the same period while per unit operating expense decreased due to lower carbon tax compliance costs in Q1/2026.

Operating expense of $12.99/boe for Q1/2026 is slightly below our annual guidance range of $13.75 - $14.25/boe for 2026.

TRANSPORTATION EXPENSE

Transportation expense includes the costs incurred to move production via truck or pipeline to the sales point. Transportation expense can vary from period to period as we seek to optimize sales prices and transportation rates. The following table compares our transportation expense for the three months ended March 31, 2026 and 2025.

	Three Months Ended March 31		
($ thousands except for per boe)	**2026**	2025	Change
Transportation expense - continuing operations	**$ 23,134**	$ 18,779	$ 4,355
Transportation expense - discontinued operations	**—**	11,733	(11,733)
Total transportation expense	**$ 23,134**	$ 30,512	$ (7,378)
Transportation expense per boe (1) - continuing operations	**$ 3.70**	$ 3.34	$ 0.36
Transportation expense per boe (1) - discontinued operations	**$ —**	$ 1.59	$ (1.59)
Total transportation expense per boe (1)	**$ 3.70**	$ 2.35	$ 1.35

(1) Transportation expense per boe is calculated as transportation expense divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.

Transportation expense for continuing operations was $23.1 million ($3.70/boe) for Q1/2026 compared to $18.8 million ($3.34/boe) for Q1/2025. The increase in transportation expense for Q1/2026 reflects higher heavy oil production relative to Q1/2025. Transportation expense of $3.70/boe for Q1/2026 is consistent with expectations and slightly above our annual guidance range of $3.40 - $3.60/boe for 2026.

BLENDING AND OTHER EXPENSE

Blending and other expense primarily includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil transported through pipelines in order to meet pipeline specifications. The purchased diluent is recorded as blending and other expense. The price received for the blended product is recorded as heavy oil sales revenue. We net blending and other expense against heavy oil sales to compare the realized price on our produced volumes to benchmark pricing.

Blending and other expense was $75.9 million for Q1/2026 compared to $72.8 million for Q1/2025. Blending and other expense for Q1/2026 was higher than Q1/2025 as heavy oil production was higher over the same period.

FINANCIAL DERIVATIVES

As part of our normal operations, our business is exposed to fluctuations in commodity prices, foreign exchange rates, interest rates and changes in our share price. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to reduce the volatility in our cash flow. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets fluctuate and as new contracts are entered into.

The following table summarizes the results of our financial derivative contracts for the three months ended March 31, 2026 and 2025.

	Three Months Ended March 31		
($ thousands)	**2026**	2025	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ (29,891)**	$ (834)	$ (29,057)
Natural gas	**602**	640	(38)
Total	**$ (29,289)**	$ (194)	$ (29,095)
Unrealized financial derivatives gain (loss)			
Crude oil	**$ (122,070)**	$ (34,041)	$ (88,029)
Natural gas	**603**	(15,384)	15,987
Total	**$ (121,467)**	$ (49,425)	$ (72,042)
Total financial derivatives gain (loss)			
Crude oil	**$ (151,961)**	$ (34,875)	$ (117,086)
Natural gas	**1,205**	(14,744)	15,949
Total	**$ (150,756)**	$ (49,619)	$ (101,137)

We recorded total financial derivatives losses of $150.8 million for Q1/2026 compared to $49.6 million for Q1/2025. The realized financial derivatives loss of $29.3 million for Q1/2026 was primarily a result of the market prices for crude oil settling at levels above those set in our derivative contracts following the increase in benchmark oil prices in March 2026. The unrealized financial derivatives loss of $121.5 million for Q1/2026 is primarily due to the increase in forecasted crude oil pricing used to revalue outstanding volumes on crude oil contracts in place at March 31, 2026, which were entered into prior to the sale of our U.S. operations, relative to December 31, 2025. The fair value of our financial derivative contracts resulted in a net liability of $95.0 million at March 31, 2026 compared to a net asset of $26.5 million at December 31, 2025.

Refer to Note 18 of the consolidated financial statements for a complete listing of our outstanding contracts at May 7, 2026.

OPERATING NETBACK

The following table summarizes our operating netback on a per boe basis for the three months ended March 31, 2026 and 2025.

	Three Months Ended March 31		
($ per boe except for volume)	**2026**	2025	Change
Daily production (boe/d) - continuing operations	**69,478**	62,380	11 %
Daily production (boe/d) - discontinued operations	**—**	81,814	(100)%
Total production (boe/d)	**69,478**	144,194	(52)%
Operating netback:			
Total sales, net of blending and other expense [(1)]	**$ 60.30**	$ 67.92	$ (7.62)
Less:			
Royalties [(2)]	**(8.25)**	(10.55)	2.30
Operating expense [(2)]	**(12.99)**	(13.46)	0.47
Transportation expense [(2)]	**(3.70)**	(3.34)	(0.36)
Operating netback [(1)] - continuing operations	**$ 35.36**	$ 40.57	$ (5.21)
Operating netback [(1)] - discontinued operations	**—**	42.44	(42.44)
Operating netback [(1)]	**$ 35.36**	$ 41.63	$ (6.27)
Realized financial derivatives loss [(3)]	**(4.68)**	(0.01)	(4.67)
Operating netback after financial derivatives [(1)]	**$ 30.68**	$ 41.62	$ (10.94)

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

(2) Refer to Royalties, Operating Expense and Transportation Expense sections in this MD&A for a description of the composition these measures.

(3) Calculated as realized financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

Our operating netback for continuing operations of $35.36/boe for Q1/2026 was lower than $40.57/boe for Q1/2025 due to the decrease in our realized price which resulted in lower per unit sales net of royalties. Combined operating and transportation expense for Q1/2026 was consistent with the same period of 2025. Our operating netback after financial derivatives of $30.68/boe for Q1/2026 was lower than $41.62/boe for Q1/2025 due to lower realized pricing along with a higher realized financial derivatives loss in Q1/2026 compared to Q1/2025.

GENERAL AND ADMINISTRATIVE EXPENSE

General and administrative ("G&A") expense includes head office and corporate costs such as salaries and employee benefits, public company costs and administrative recoveries earned for operating exploration and development activities on behalf of our working interest partners. G&A expense fluctuates with head office staffing levels and the level of operated exploration and development activity during the period.

The following table summarizes our G&A expense for the three months ended March 31, 2026 and 2025.

	Three Months Ended March 31		
($ thousands except for per boe)	**2026**	2025 (1)	Change
Gross G&A expense - continuing operations	**$ 24,231**	$ 20,624	$ 3,607
Overhead recoveries - continuing operations	**(1,932)**	(2,058)	126
G&A expense - continuing operations	**$ 22,299**	$ 18,566	$ 3,733
G&A expense - discontinued operations (2)	**—**	7,040	(7,040)
Total G&A expense	**$ 22,299**	$ 25,606	$ (3,307)
G&A expense per boe (3) - continuing operations	**$ 3.57**	$ 3.31	$ 0.26
G&A expense per boe (3) - discontinued operations	**$ —**	$ 0.96	$ (0.96)
Total G&A expense per boe (3)	**$ 3.57**	$ 1.97	$ 1.60

(1) Comparative period revised to reflect current period presentation. Refer to Note 6 of the consolidated financial statements for additional information.
(2) General and administrative expense for discontinued operations is net of recoveries.
(3) General and administrative expense per boe is calculated as general and administrative expense divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.

G&A expense for continuing operations was $22.3 million ($3.57/boe) for Q1/2026 compared to $18.6 million ($3.31/boe) for Q1/2025. G&A expense for continuing operations includes severance and other non-recurring costs related to staff reductions in Canada of approximately $5.5 million which resulted in higher G&A expense for Q1/2026 compared to Q1/2025.

NET FINANCING AND INTEREST EXPENSE

Net financing and interest includes interest expense on our credit facilities, long-term notes and lease obligations, interest income earned on our cash deposits, as well as non-cash financing costs which include the accretion on our debt issue costs and asset retirement obligations. Net financing and interest varies depending on debt levels outstanding during the period, the applicable borrowing rates, CAD/USD foreign exchange rates, cash deposits held during the period, along with the carrying amount of asset retirement obligations and the discount rates used to present value these obligations.

The following table summarizes our financing and interest expense for the three months ended March 31, 2026 and 2025.

	Three Months Ended March 31		
($ thousands except for per boe)	**2026**	2025 (1)	Change
Interest on credit facilities	**$ 887**	$ 3,337	$ (2,450)
Interest on long-term notes	**1,719**	40,279	(38,560)
Interest on lease obligations	**1,095**	325	770
Interest income	**(6,455)**	(350)	(6,105)
Net cash interest (income) expense	**$ (2,754)**	$ 43,591	$ (46,345)
Amortization of debt issue costs	**516**	2,378	(1,862)
Accretion of asset retirement obligations	**5,038**	4,598	440
Early redemption expense	**297**	—	297
Net financing and interest expense - continuing operations	**$ 3,097**	$ 50,567	$ (47,470)
Net financing and interest expense - discontinued operations	**—**	4,679	(4,679)
Total net financing and interest expense	**$ 3,097**	$ 55,246	$ (52,149)
Net financing and interest expense per boe (2) - continuing operations	**$ 0.50**	$ 9.01	$ (8.51)
Net financing and interest expense per boe (2) - discontinued operations	**$ —**	$ 0.64	$ (0.64)
Total net financing and interest expense per boe (2)	**$ 0.50**	$ 4.26	$ (3.76)

(1) Comparative period revised to reflect current period presentation. Refer to Note 6 of the consolidated financial statements for additional information.
(2) Calculated as net financing and interest expense divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.

Net financing and interest expense for continuing operations was $3.1 million ($0.50/boe) for Q1/2026 compared to $50.6 million ($9.01/boe) for Q1/2025. Lower net financing and interest expense for Q1/2026 reflects the repayment of nearly all of our outstanding debt following the Eagle Ford disposition in Q4/2025.

We recorded net cash interest income for continuing operations of $2.8 million for Q1/2026 compared to expense of $43.6 million for Q1/2025. In Q4/2025, we repaid the majority of our outstanding credit facilities, redeemed the 8.5% Senior Notes and partially redeemed the 7.375% Senior Notes which resulted in lower interest on our credit facilities and long-term notes in Q1/2026. Interest on our credit facilities for Q1/2026 reflects the standby fees rate of 0.5% compared to the weighted average interest rate of 6.9% for Q1/2025. Interest income for Q1/2026 reflects interest earned on cash deposits held in high-interest savings accounts during the period.

Accretion of asset retirement obligations of $5.0 million for Q1/2026 was consistent with $4.6 million for Q1/2025. Amortization of debt issue costs of $0.5 million for Q1/2026 was lower than $2.4 million for Q1/2025 due to the de-recognition of debt issue costs associated with the credit facilities and the long-term notes in Q4/2025.

EXPLORATION AND EVALUATION EXPENSE

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense from continuing operations was $0.7 million for Q1/2026 compared to $0.1 million for Q1/2025.

DEPLETION AND DEPRECIATION

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved and probable reserves volumes and the rate of production for the period. The following table summarizes depletion and depreciation expense for the three months ended March 31, 2026 and 2025.

	Three Months Ended March 31		
($ thousands except for per boe)	**2026**	2025 [1]	Change
Depletion and depreciation - continuing operations	**$ 123,690**	$ 116,743	$ 6,947
Depletion and depreciation - discontinued operations	**—**	203,180	(203,180)
Total depletion and depreciation	**$ 123,690**	$ 319,923	$ (196,233)
Depletion and depreciation per boe [2] - continuing operations	**$ 19.78**	$ 20.79	$ (1.01)
Depletion and depreciation per boe [2] - discontinued operations	**$ —**	$ 27.59	$ (27.59)
Total depletion and depreciation per boe [2]	**$ 19.78**	$ 24.65	$ (4.87)

(1) Comparative period revised to reflect current period presentation. Refer to Note 6 of the consolidated financial statements for additional information.

(2) Depletion and depreciation expense per boe is calculated as depletion and depreciation expense divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued or total operations.

Depletion and depreciation expense for continuing operations was $123.7 million ($19.78/boe) for Q1/2026 compared to $116.7 million ($20.79/boe) for Q1/2025. Depletion and depreciation expense for continuing operations was higher in Q1/2026 relative to Q1/2025 due to higher production which was partially offset by a reduction to the depletion rate of our oil and gas properties at Q1/2026.

IMPAIRMENT

We assessed our oil and gas properties and exploration and evaluation assets for indicators of impairment or impairment reversal and concluded that the estimation of recoverable amount was not required for any of our cash generating units at March 31, 2026.

SHARE-BASED COMPENSATION EXPENSE

Share-based compensation ("SBC") expense includes expense associated with our Share Award Incentive Plan, Incentive Award Plan, and Deferred Share Unit Plan. SBC expense associated with cash-settled awards is recognized in net income or loss over the vesting period of the awards with a corresponding share-based compensation liability. SBC expense varies with the quantity of share awards outstanding and changes in the market price of our common shares.

We recorded SBC expense of $22.9 million for Q1/2026 for our continuing operations compared to $0.4 million for Q1/2025. The increase for Q1/2026 primarily reflects the Company's share price, which increased the value of the awards resulting in higher SBC expense relative to Q1/2025. The total expense for Q1/2026 for continuing operations is comprised of $18.0 million of cash expense and $4.9 million of non-cash expense for awards designated as equity-settled.

FOREIGN EXCHANGE

Unrealized foreign exchange gains and losses are primarily a result of changes in the reported amount of our U.S. dollar denominated long-term notes and credit facilities in our Canadian functional currency entities. The long-term notes and credit facilities are translated to Canadian dollars on the balance sheet date using the closing CAD/USD exchange rate resulting in unrealized gains and losses. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in our Canadian functional currency entities.

	Three Months Ended March 31		
($ thousands except for exchange rates)	**2026**	2025	Change
Unrealized foreign exchange loss (gain)	**$ 1,630**	$ (3,475)	$ 5,105
Realized foreign exchange loss (gain)	**304**	(403)	707
Foreign exchange loss (gain) - continuing operations	**$ 1,934**	$ (3,878)	$ 5,812
CAD/USD exchange rates:			
At beginning of period	**1.3715**	1.4405	
At end of period	**1.3956**	1.4379	

We recorded a foreign exchange loss for continuing operations of $1.9 million for Q1/2026 compared to a gain of $3.9 million for Q1/2025.

The unrealized foreign exchange loss for continuing operations of $1.6 million for Q1/2026 is related to changes in the reported amount of our U.S. dollar denominated long-term notes due to the weakening of the Canadian dollar relative to the U.S. dollar at March 31, 2026 compared to December 31, 2025. The unrealized foreign exchange gain of $3.5 million for Q1/2025 is related to changes in the reported amount of our long-term notes and credit facilities due to the strengthening of the Canadian dollar relative to the U.S. dollar at March 31, 2025 compared to December 31, 2024.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange loss for continuing operations of $0.3 million for Q1/2026 compared to a gain of $0.4 million for Q1/2025.

INCOME TAXES

	Three Months Ended March 31		
($ thousands)	**2026**	2025 (1)	Change
Current income tax expense	**$ —**	$ 947	$ (947)
Deferred income tax (recovery) expense	**(24,253)**	8,362	(32,615)
Income tax (recovery) expense - continuing operations	**$ (24,253)**	$ 9,309	$ (33,562)
Income tax expense - discontinued operations	**$ —**	$ 11,454	$ (11,454)

(1) Comparative period revised to reflect current period presentation. Refer to Note 6 of the consolidated financial statements for additional information.

We did not record current income tax for continuing operations in Q1/2026 and recorded an expense of $0.9 million for Q1/2025.

We recorded a deferred income tax recovery for continuing operations of $24.3 million for Q1/2026 compared to expense of $8.4 million for Q1/2025. The deferred tax recovery for Q1/2026 reflects a net loss from continuing operations.

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency ("CRA") that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. Following objections and submissions, in November 2023 the CRA issued notices of confirmation regarding their prior reassessments. In February 2024, Baytex filed notices of appeal with the Tax Court of Canada (“TCC”) and we estimate it could take another two to three years to receive a judgment. The reassessments do not require us to pay any amounts in order to participate in the appeals process. Should we be unsuccessful at the TCC, additional appeals are available; a process that we estimate could take another two years and potentially longer.

We remain confident that the tax filings of the affected entities are correct and will defend our tax filing positions. During 2023, we purchased $272.5 million of insurance coverage for a premium of $50.3 million which will help manage the litigation risk associated with this matter. The most recent statement of account issued by the CRA assert taxes owing by the trusts of $244.8 million, late payment interest of $244.2 million and a late filing penalty in respect of the 2011 tax year of $4.1 million.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591.0 million (the "Losses"). The Losses were subsequently deducted in computing the taxable income of those trusts. The reassessments, as confirmed in November 2023, disallow the deduction of the Losses for two reasons. First, the reassessments allege that the trusts were resettled and the resulting successor trusts were not able to access the losses of the predecessor trusts. Second, the reassessments allege that the general anti-avoidance rule of the Income Tax Act (Canada) operates to deny the deduction of the losses. In September 2025, the Department of Justice, legal counsel for the Crown, abandoned the position that the trusts were resettled. The issue of whether the general anti-avoidance rule applies remains in dispute. If, after exhausting available appeals, the deduction of the Losses continues to be disallowed, either the trusts or their corporate beneficiary will owe cash taxes, late payment interest and potential penalties. The amount of cash taxes owing, late payment interest and potential penalties are dependent upon the taxpayer(s) ultimately liable (the trusts or their corporate beneficiary) and the amount of unused tax shelter available to the taxpayer(s) to offset the reassessed income, including tax shelter from subsequent years that may be carried back and applied to prior years.

NET INCOME (LOSS) AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income or loss for the three months ended March 31, 2026 and 2025 are set forth in the following table.

	Three Months Ended March 31		
($ thousands)	**2026**	2025 (1)	Change
Petroleum and natural gas sales	**$ 452,954**	$ 454,151	$ (1,197)
Royalties	**(51,589)**	(59,256)	7,667
Revenue, net of royalties	**401,365**	394,895	6,470
Expenses			
Operating	**(81,244)**	(75,580)	(5,664)
Transportation	**(23,134)**	(18,779)	(4,355)
Blending and other	**(75,921)**	(72,820)	(3,101)
Operating netback (2)	**$ 221,066**	$ 227,716	$ (6,650)
General and administrative	**(22,299)**	(18,566)	(3,733)
Net cash interest income (expense)	**2,754**	(43,591)	46,345
Realized financial derivatives loss	**(29,289)**	(194)	(29,095)
Realized foreign exchange (loss) gain	**(304)**	403	(707)
Cash other expense	**(1,704)**	(2,396)	692
Current income tax expense	**—**	(947)	947
Cash share-based compensation	**(18,013)**	(413)	(17,600)
Adjusted funds flow (3)	**$ 152,211**	$ 162,012	$ (9,801)
Exploration and evaluation	**(665)**	(107)	(558)
Depletion and depreciation	**(123,690)**	(116,743)	(6,947)
Non-cash share-based compensation	**(4,857)**	—	(4,857)
Non-cash financing and interest	**(5,851)**	(6,976)	1,125
Unrealized financial derivatives loss	**(121,467)**	(49,425)	(72,042)
Unrealized foreign exchange (loss) gain	**(1,630)**	3,475	(5,105)
Gain (loss) on dispositions	**2,017**	(1,229)	3,246
Deferred income tax recovery (expense)	**24,253**	(8,362)	32,615
Net loss from continuing operations	**$ (79,679)**	$ (17,355)	$ (62,324)
Net income from discontinued operations	**12,353**	86,946	(74,593)
Net (loss) income	**$ (67,326)**	$ 69,591	$ (136,917)

(1) Comparative period revised to reflect current period presentation. Refer to Note 6 of the consolidated financial statements for additional information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

We generated adjusted funds flow of $152.2 million for Q1/2026 compared to $162.0 million for Q1/2025. Adjusted funds flow for Q1/2026 includes realized financial derivatives losses of $29.3 million due to benchmark oil prices above our contracted prices and cash share-based compensation expense of $18.0 million due to an increase in our share price. We recorded net cash interest income in Q1/2026, reflecting interest earned on cash deposits held in high-interest savings accounts and lower interest expense from the repayment of the majority of our debt following the U.S. disposition in Q4/2025.

We reported a net loss from continuing operations of $79.7 million for Q1/2026 compared to $17.4 million for Q1/2025. The increase in net loss for Q1/2026 relative to Q1/2025 is primarily a result of an unrealized financial derivatives loss of $121.5 million driven by the sharp increase in near-term oil prices in March 2026.

CAPITAL EXPENDITURES

Capital expenditures for the three months ended March 31, 2026 and 2025 are summarized as follows.

	Three Months Ended March 31		
($ thousands)	**2026**	2025	Change
Drilling, completion and equipping	**$ 121,580**	$ 167,478	$ (45,898)
Facilities and other	**23,432**	16,841	6,591
Exploration and development expenditures - continuing operations	**$ 145,012**	$ 184,319	$ (39,307)
Exploration and development expenditures - discontinued operations	**—**	220,778	(220,778)
Total exploration and development expenditures	**$ 145,012**	$ 405,097	$ (260,085)
Property acquisitions - continuing operations	**$ 8,127**	$ 469	$ 7,658
Proceeds from dispositions - continuing operations	**$ 40**	$ (2,677)	$ 2,717
Property acquisitions - discontinued operations	**$ —**	$ 788	$ (788)
Proceeds from dispositions - discontinued operations	**$ (13,153)**	$ 411	$ (13,564)

Exploration and development expenditures for continuing operations were $145.0 million in Q1/2026 which is $39.3 million lower compared to $184.3 million in Q1/2025. Exploration and development expenditures for Q1/2026 included costs associated with drilling 58 (52.5 net) wells along with 54 (52.7 net) wells that were brought on production compared to drilling 90 (85.5 net) wells along with 77 (75.0 net) wells brought on production during Q1/2025. We also invested $23.4 million on facilities and other expenditures during Q1/2026.

Exploration and development expenditures of $145.0 million for Q1/2026 were consistent with expectations and our annual guidance for 2026 of approximately $625 million.

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain a strong financial position that provides flexibility to execute our development programs, provide returns to shareholders and optimize our portfolio through strategic acquisitions. Baytex assesses its capital structure in response to operational requirements and changes in economic conditions. At March 31, 2026, the Company's capital structure was comprised of shareholders' capital, long-term notes, trade receivables, prepaids and other assets, inventory, trade payables, share-based compensation liability, dividends payable, cash and the Credit Facilities.

In order to manage its capital structure and liquidity, Baytex may from time-to-time issue or repurchase equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

At March 31, 2026 we had net cash[1] of $591.2 million compared to $765.8 million at December 31, 2025. The decrease in net cash from December 31, 2025 reflects shareholder returns of $190.9 million during Q1/2026 which includes share buybacks and quarterly dividends.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

Credit Facilities

At March 31, 2026, Baytex had $750 million of revolving credit facilities (the "Credit Facilities") that mature on June 27, 2030. The Credit Facilities are secured and are comprised of a $50 million operating loan and a $700 million syndicated revolving loan. The Credit Facilities were undrawn at March 31, 2026.

There are no mandatory principal payments required prior to maturity which could be extended upon our request. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. Advances under the Baytex Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, Canadian Overnight Repo Rate Average rates or Secured Overnight Financing Rates, plus applicable margins.

At March 31, 2026, Baytex had $4.4 million of outstanding letters of credit (December 31, 2025 - $4.4 million outstanding) under the Credit Facilities.

The agreements and associated amending agreements relating to the Credit Facilities are accessible on the SEDAR+ website at www.sedarplus.ca and through the U.S. Securities and Exchange Commission at www.sec.gov.

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at March 31, 2026.

Covenant Description	Position as at March 31, 2026	Covenant
Senior Secured Debt [(1)] to Bank EBITDA [(2)] (Maximum Ratio)	**0:0:1.0**	3.5:1.0
Interest Coverage [(3)] (Minimum Ratio)	**5.5:1.0**	3.5:1.0
Total Debt [(4)] to Bank EBITDA [(2)] (Maximum Ratio)	**0.1:1.0**	4.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at March 31, 2026, the Company's Senior Secured Debt totaled $4.4 million.

(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility agreement which adjusts net income or loss for financing and interest expense, income taxes, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material dispositions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended March 31, 2026 was $661.0 million.

(3) "Interest coverage" is calculated in accordance with the credit facility agreement and is computed as the ratio of Bank EBITDA to financing and interest expense, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis including the impact of material dispositions as if they had occurred at the beginning of the twelve month period. Financing and interest expense for the twelve months ended March 31, 2026 was $119.4 million.

(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade payables, share-based compensation liability, dividends payable, asset retirement obligations, lease obligations, deferred income tax liability, and financial derivative liabilities. As at March 31, 2026, the Company's Total Debt totaled $93.9 million of principal amounts outstanding.

Long-Term Notes

During Q1/2026, Baytex repurchased and cancelled US$5.8 million principal amount of the 7.375% Senior Notes at 103.613% of par value and recorded an early redemption expense of $0.3 million. The 7.375% Senior Notes were issued on April 1, 2024 and US$64.1 million remains outstanding as at March 31, 2026. The 7.375% Senior Notes mature on March 15, 2032 and are redeemable at our option, in whole or in part, at specified redemption prices on or after March 15, 2027 and will be redeemable at par from March 15, 2029 to maturity.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the three months ended March 31, 2026, we issued 0.1 million common shares pursuant to our share-based compensation program. As at March 31, 2026, we had 730.6 million common shares issued and outstanding and no preferred shares issued and outstanding. As at May 7, 2026, there were 723.4 million common shares issued and outstanding and no preferred shares issued and outstanding.

During the three months ended March 31, 2026, we repurchased 35.1 million common shares under our normal course issuer bid ("NCIB") at an average price of $4.96 per share for total consideration of $174.3 million. At March 31, 2026, we had 28.4 million shares remaining on our NCIB which expires on July 2, 2026. We have obtained an exemption order from the Canadian securities regulators which permits us to purchase its common shares through the NYSE and other U.S. based trading systems.

During the three months ended March 31, 2026, we recorded a $3.4 million charge to shareholders' capital related to the federal tax on equity repurchases (December 31, 2025 - $0.5 million).

On January 2 and April 1, 2026, we paid a quarterly cash dividend of $0.0225 per share to shareholders of record. On May 7, 2026, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on July 2, 2026 to shareholders of record on June 15, 2026. These dividends are designated as “eligible dividends” for Canadian income tax purposes. These dividends are considered “qualified dividends” for U.S income tax purposes.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of March 31, 2026 and the expected timing for funding these obligations are noted in the table below.

($ thousands)	**Total**	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Credit facilities - principal [(1)]	**$ —**	$ —	$ —	$ —	$ —
Long-term notes - principal	**89,507**	—	—	—	89,507
Interest on long-term notes	**39,353**	6,601	13,202	13,202	6,348
Lease obligations - principal	**95,646**	14,792	22,290	17,823	40,741
Processing agreements	**4,733**	799	543	529	2,862
Transportation agreements	**74,851**	36,035	32,439	3,355	3,022
Total	**$ 304,090**	$ 58,227	$ 68,474	$ 34,909	$ 142,480

(1) The Credit Facilities were undrawn at March 31, 2026.

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities when they reach the end of their economic lives. The present value of the future estimated abandonment and reclamation costs are included in the asset retirement obligations presented in the statement of financial position. Programs to abandon and reclaim well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

The Company is, from time-to-time, subject to various claims, demands, audits and other proceedings covering matters that arise in the ordinary course of business activities. Such claims and other proceedings often relate to labour, tax, personal injury, environmental, title or commercial matters. Baytex retains liability for matters related to our prior ownership of assets located in the U.S. Resolution of these matters may have an unfavorable financial or operating impact on the Company. Certain conditions may exist as at March 31, 2026 which may result in a loss to the Company. However, the Company believes that none of these matters are expected to have a material effect on the results of operations or financial position of the Company.

The Company establishes legal provisions for known and potential claims for which payment is probable and can be reliably estimated. The Company also has comprehensive liability insurance coverage; however such insurance does not cover all risks to which we might be exposed and in other cases, may only partially cover losses incurred by the Company.

QUARTERLY FINANCIAL INFORMATION

	2026	2025				2024		
($ thousands, except per common share amounts)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Petroleum and natural gas sales	**452,954**	759,815	927,648	886,579	999,130	1,017,017	1,074,623	1,133,123
Net (loss) income - continuing operations (1)	**(79,679)**	(334,057)	(28,451)	103,018	(17,355)	(124,903)	96,204	13,751
Per common share - basic	**(0.11)**	(0.43)	(0.04)	0.13	(0.02)	(0.16)	0.12	0.02
Per common share - diluted	**(0.11)**	(0.43)	(0.04)	0.13	(0.02)	(0.16)	0.12	0.02
Net (loss) income	**(67,326)**	(856,887)	31,968	151,549	69,591	(38,477)	185,219	103,898
Per common share - basic	**(0.09)**	(1.12)	0.04	0.20	0.09	(0.05)	0.23	0.13
Per common share - diluted	**(0.09)**	(1.12)	0.04	0.20	0.09	(0.05)	0.23	0.13
Adjusted funds flow (2)	**151,125**	261,531	422,232	366,919	463,870	461,886	537,947	532,839
Per common share - basic	**0.20**	0.34	0.55	0.48	0.60	0.59	0.68	0.65
Per common share - diluted	**0.20**	0.34	0.55	0.48	0.60	0.59	0.67	0.65
Free cash flow (3)	**1,705**	76,486	142,688	3,188	52,529	254,838	220,159	180,673
Per common share - basic	**—**	0.10	0.19	—	0.07	0.33	0.28	0.22
Per common share - diluted	**—**	0.10	0.18	—	0.07	0.33	0.28	0.22
Cash flows from operating activities	**122,203**	227,657	472,676	354,312	431,317	468,865	550,042	505,584
Per common share - basic	**0.16**	0.30	0.62	0.46	0.56	0.60	0.69	0.62
Per common share - diluted	**0.16**	0.30	0.61	0.46	0.56	0.60	0.69	0.62
Dividends declared	**16,606**	17,268	17,326	17,304	17,289	17,598	17,732	18,161
Per common share	**0.0225**	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225
Exploration and development	**145,012**	174,078	270,364	356,532	405,097	198,177	306,332	339,573
Canada	**145,012**	92,720	123,579	147,734	184,319	108,971	120,473	101,916
U.S. (4)	**—**	81,358	146,785	208,798	220,778	89,206	185,859	237,657
Property acquisitions	**8,127**	5,544	24,024	1,193	1,257	12,621	1,042	3,349
Proceeds from dispositions	**(13,113)**	(3,012,058)	(8,254)	(725)	(2,266)	(42,339)	(1,436)	(2,695)
Net (cash) debt (2)	**(591,151)**	(765,785)	2,244,358	2,293,940	2,390,250	2,417,172	2,493,269	2,639,014
Total assets	**3,252,692**	3,345,414	7,601,389	7,552,013	7,824,576	7,759,745	7,614,157	7,770,926
Common shares outstanding	**730,561**	765,568	768,317	768,317	770,039	773,590	787,328	804,977
Daily production								
Total production (boe/d)	**69,478**	137,087	150,950	148,095	144,194	152,894	154,468	154,194
Canada (boe/d)	**69,478**	67,295	68,185	64,167	62,380	65,332	64,668	63,688
U.S. (boe/d) (4)	**—**	69,792	82,765	83,928	81,814	87,562	89,800	90,506
Benchmark prices								
WTI oil (US$/bbl)	**71.93**	59.14	64.93	63.74	71.42	70.27	75.10	80.57
WCS heavy oil ($/bbl)	**79.28**	66.88	75.14	74.10	84.33	80.77	83.98	91.72
Edmonton par oil ($/bbl)	**93.50**	76.49	86.20	84.15	95.27	94.98	97.91	105.30
AECO 7A natural gas ($/mcf)	**2.49**	2.34	1.00	2.07	2.02	1.46	0.81	1.44
CAD/USD avg exchange rate	**1.3716**	1.3949	1.3774	1.3840	1.4350	1.3992	1.3636	1.3684
Total sales, net of blending and other expense ($/boe) (3)	**60.30**	56.28	63.22	61.16	71.38	66.60	71.97	75.93
Royalties ($/boe) (5)	**(8.25)**	(11.54)	(13.05)	(13.16)	(16.02)	(14.69)	(15.75)	(17.14)
Operating expense ($/boe) (5)	**(12.99)**	(12.51)	(11.54)	(11.95)	(11.38)	(10.36)	(11.76)	(11.95)
Transportation expense ($/boe) (5)	**(3.70)**	(2.43)	(2.54)	(2.44)	(2.35)	(2.35)	(2.60)	(2.37)
Operating netback ($/boe) (3)	**35.36**	29.80	36.09	33.61	41.63	39.20	41.86	44.47
Financial derivatives (loss) gain ($/boe) (5)	**(4.68)**	0.08	(0.62)	(0.88)	(0.01)	(0.15)	0.02	(0.16)
Operating netback after financial derivatives ($/boe) (3)	**30.68**	29.88	35.47	32.73	41.62	39.05	41.88	44.31

(1) Previously disclosed amounts have been revised to conform with current period presentation.
(2) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(4) The Company's U.S. operations were disposed in December 2025.
(5) Calculated as royalties, operating expense, transportation expense or financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

Our results for the previous eight quarters reflect the disciplined execution of our capital programs while oil and natural gas prices have fluctuated, along with acquisition and disposition activity. Production of 69,478 boe/d in Q1/2026 reflects our Canadian operations following the Eagle Ford disposition in Q4/2025. Our successful light and heavy oil development programs in Canada for Q1/2026 resulted in production growth to 69,478 boe/d from 63,688 boe/d in Q2/2024 despite the disposition of certain thermal assets in Q4/2024.

Benchmark prices for crude oil declined from Q2/2024 through Q4/2025 due to increasing supply from OPEC+ and North American production growth along with concerns over slowing global economic activity. Prices sharply increased in March 2026 due to supply disruptions related to the conflict in Iran and resulted in realized pricing of $60.30/boe for Q1/2026 and operating netback after financial derivatives of $30.68/boe. Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow(1) of $151.1 million and cash flows from operating activities of $122.2 million for Q1/2026 reflect strong operating performance from our light and heavy oil assets.

In Q4/2025, we completed the disposition of the Eagle Ford assets which resulted in net cash(1) of $591.2 million at Q1/2026 compared to a net debt position of $2.6 billion at Q2/2024. The change in net (cash) debt also reflects free cash flow(2) of $932.3 million generated in the period since Q2/2024, along with $557.3 million of shareholder returns including share buybacks and quarterly dividends.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.

ENVIRONMENTAL REGULATIONS

As a result of our involvement in the exploration for and production of oil and natural gas we are subject to various emissions, carbon and other environmental regulations. Refer to the AIF for the year ended December 31, 2025 for a full description of the risks associated with these regulations and how they may impact our business in the future.

Reporting Regulations

Environmental reporting for public enterprises continues to evolve and the Company may be subject to additional future disclosure requirements. The International Sustainability Standards Board ("ISSB") has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Sustainability Standards Board has released voluntary standards for reporting periods starting on or after January 1, 2025 that are aligned with the ISSB release and include suggestions for Canadian-specific modifications. The Canadian Securities Administrators ("CSA") have also issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters which sets forth additional reporting requirements for Canadian Public Companies. In April 2025, the CSA announced it is pausing development of new sustainability reporting requirements to allow issuers to adapt to recent developments in the U.S. and globally. Baytex continues to monitor developments on these reporting requirements and has not yet quantified the cost to comply with these regulations.

OFF BALANCE SHEET TRANSACTIONS

We do not have any material financial arrangements that are excluded from the consolidated financial statements as at March 31, 2026, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the three months ended March 31, 2026. Further information on our critical accounting policies and estimates can be found in the notes to the audited annual consolidated financial statements and MD&A for the year ended December 31, 2025.

CHANGES IN ACCOUNTING POLICIES

Effective January 1, 2026, Baytex adopted amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* which were issued by the IASB in May 2024. The amendments further clarify the date of recognition and derecognition of financial assets and liabilities. These amendments have not had a material impact on our consolidated financial statements. The amendments have been applied retrospectively with no restatement of comparative information, in accordance with transition requirements on initial application of IFRS 9. The adjustment to the cash balance is reflected as a $1.8 million increase to the opening balance of cash in the consolidated statements of cash flows.

SPECIFIED FINANCIAL MEASURES

In this MD&A, we refer to certain specified financial measures (such as total sales, net of blending and other expense, heavy oil sales, net of blending and other expense, operating netback, free cash flow, and average royalty rate) which do not have any standardized meaning prescribed by IFRS. While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. This MD&A also contains the terms "adjusted funds flow" and "net cash" which are capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

Non-GAAP Financial Measures

Total sales, net of blending and other expense and heavy oil, net of blending and other expense

Total sales, net of blending and other expense and heavy oil, net of blending and other expense represent the total revenues and heavy oil revenues realized from produced volumes during a period, respectively. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. Heavy oil, net of blending and other expense is calculated as heavy oil sales less blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

The following table reconciles heavy oil, net of blending and other expense to amounts disclosed in the primary financial statements from continuing operations.

	Three Months Ended March 31	
($ thousands)	**2026**	2025
Petroleum and natural gas sales	**$ 452,954**	$ 454,151
Light oil and condensate [1]	**(88,993)**	(99,469)
NGL [1]	**(8,560)**	(7,888)
Natural gas [1]	**(8,664)**	(8,083)
Heavy oil	**$ 346,737**	$ 338,711
Blending and other expense [2]	**(75,921)**	(72,820)
Heavy oil, net of blending and other expense - continuing operations	**$ 270,816**	$ 265,891

(1) Component of petroleum and natural gas sales. See Note 14 - Petroleum and Natural Gas Sales in the consolidated financial statements for the three months ended March 31, 2026 for further information.
(2) The portion of blending and other expense that relates to heavy oil sales for the applicable period.

Operating netback

Operating netback and operating netback after financial derivatives are used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

The following table reconciles operating netback and operating netback after realized financial derivatives to petroleum and natural gas sales from continuing operations.

	Three Months Ended March 31	
($ thousands)	**2026**	2025
Petroleum and natural gas sales	**$ 452,954**	$ 454,151
Blending and other expense	**(75,921)**	(72,820)
Total sales, net of blending and other expense	**377,033**	381,331
Royalties	**(51,589)**	(59,256)
Operating expense	**(81,244)**	(75,580)
Transportation expense	**(23,134)**	(18,779)
Operating netback - continuing operations	**$ 221,066**	$ 227,716
Realized financial derivatives loss [1]	**(29,289)**	(194)
Operating netback after realized financial derivatives - continuing operations	**$ 191,777**	$ 227,522

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss. See Note 18 - Financial Instruments and Risk Management in the consolidated financial statements for the three months ended March 31, 2026 for further information.

Free cash flow

We use free cash flow to evaluate our financial performance and to assess the cash available for debt repayment, common share repurchases, dividends and acquisition opportunities. Free cash flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, additions to exploration and evaluation assets, additions to oil and gas properties, payments on lease obligations, and transaction costs.

Free cash flow is reconciled to cash flows from operating activities in the following table.

	Three Months Ended March 31	
($ thousands)	**2026**	2025
Cash flows from operating activities	**$ 122,203**	$ 431,317
Change in non-cash working capital	**26,303**	29,034
Additions to exploration and evaluation assets	**(1,737)**	—
Additions to oil and gas properties	**(143,275)**	(405,097)
Payments on lease obligations	**(1,789)**	(2,725)
Free cash flow	**$ 1,705**	$ 52,529

Non-GAAP Financial Ratios

Heavy oil, net of blending and other expense per bbl

Heavy oil, net of blending and other expense per bbl represents the realized price for produced heavy oil volumes during a period. Heavy oil, net of blending and other expense is a non-GAAP measure that is divided by barrels of heavy oil production volume for the applicable period for continuing operations to calculate the ratio. We use heavy oil, net of blending and other expense per bbl to analyze our realized heavy oil price for produced volumes against the WCS benchmark price in Canada.

Total sales, net of blending and other expense per boe

Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period for continuing or total operations.

Average royalty rate

Average royalty rate is used to evaluate the performance of our operations from period to period and is comprised of royalties divided by total sales, net of blending and other expense (a non-GAAP financial measure) for continuing or total operations. Average royalty rate for discontinued operations is calculated as royalties divided by total petroleum and natural gas sales. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction.

Operating netback per boe

Operating netback per boe is operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period for continuing, discontinued, or total operations and is used to assess our operating performance on a unit of production basis. Realized financial derivative gains and losses per boe are added to operating netback per boe to arrive at operating netback after financial derivatives per boe. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

Capital Management Measures

Net cash

We use net cash to monitor our current financial position and to evaluate existing sources of liquidity. We also use net cash projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net cash is comprised of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade payables, share-based compensation liability, dividends payable, cash, trade receivables, prepaids and other assets, and inventory.

The following table summarizes our calculation of net cash.

	As at	
($ thousands)	**March 31, 2026**	December 31, 2025
Credit facilities	**$ —**	$ 1,138
Unamortized debt issuance costs - Credit facilities (1)	**—**	262
Long-term notes	**87,598**	93,834
Unamortized debt issuance costs - Long-term notes (1)	**1,909**	2,113
Trade payables	**303,107**	236,373
Share-based compensation liability	**25,748**	34,802
Dividends payable	**16,606**	17,268
Cash	**(757,869)**	(953,113)
Trade receivables	**(194,985)**	(135,230)
Prepaids and other assets	**(59,091)**	(63,232)
Inventory	**(14,174)**	—
Net cash	**$ (591,151)**	$ (765,785)

(1) Unamortized debt issuance costs were obtained from Note 8 - Credit Facilities and Note 9 - Long-term Notes from the consolidated financial statements for the three months ended March 31, 2026. These amounts represent the remaining balance of costs that were paid by Baytex at the inception of the contract.

Adjusted funds flow

Adjusted funds flow is used to monitor operating performance and the Company's ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital and asset retirements obligations settled during the applicable period.

Adjusted funds flow is reconciled to amounts disclosed in the primary financial statements in the following table.

	Three Months Ended March 31	
($ thousands)	**2026**	2025
Cash flow from operating activities	**$ 122,203**	$ 431,317
Change in non-cash working capital	**26,303**	29,034
Asset retirement obligations settled	**2,619**	3,519
Adjusted funds flow	**$ 151,125**	$ 463,870

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any material weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no material weaknesses or such changes were identified in our internal controls over financial reporting during the three months ended March 31, 2026.

FORWARD-LOOKING STATEMENTS

In the interest of providing our shareholders and potential investors with information regarding Baytex, including management's assessment of the Company's future plans and operations, certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "plan", "project", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to but not limited to: our 2026 guidance for: exploration and development expenditures, average daily production, royalty rate and operating expense, transportation expense, lease expenditures and asset retirement obligations settled; the we intend to reduce cash flow volatility by using financial derivates; the expected time to resolve the reassessment of our tax filings by the Canada Revenue Agency; our objective to maintain a strong balance sheet to execute development programs, deliver shareholder returns and optimize our portfolio through strategic acquisitions and dispositions; that we may issue or repurchase debt or equity securities from time to time and sell adjust or adjust capital spending; our intent to fund a significant portion of our financial obligations with adjusted funds flow and the expected timing of those financial obligations. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy crude oil prices; well production rates and reserve volumes; success obtained drilling new wells; the duration and impact of tariffs that are currently in effect on goods exported from or imported into Canada, and that other than the tariffs that are currently in effect, neither the U.S. nor Canada (i) increases the rate or scope of such tariffs, reenacts tariffs that are currently suspended, or imposes new tariffs, on the import of goods from one country to the other, including on oil and natural gas, and/or (ii) imposes any other form of tax, restriction or prohibition on the import or export of products from one country to the other, including on oil and natural gas; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; operating costs; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; our ability to successfully market oil and natural gas; that we will have sufficient financial resources in the future to pursue our development plans and provide shareholder returns; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the risk of an extended period of low oil and natural gas prices (including as a result of tariffs); risks associated with our ability to develop our properties and add reserves; that we may not achieve the expected benefits of acquisitions and we may sell assets below their carrying value; the availability and cost of capital or borrowing; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; the impact of an energy transition on demand for petroleum productions; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; risks associated with large projects; risks associated with higher a higher concentration of activity and tighter drilling spacing; costs to develop and operate our properties; current or future controls, legislation or regulations; restrictions on or access to water or other fluids; public perception and its influence on the regulatory regime; new regulations on hydraulic fracturing; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy crude oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; adverse results of litigation; that our Credit Facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with expansion into new activities; the impact of Indigenous claims; risks of counterparty default; impact of geopolitical risk and conflicts; loss of foreign private issuer status; conflicts of interest between the Company and its directors and officers; variability of share buybacks and dividends; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2025, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

The future acquisition of our common shares pursuant to a share buyback (including through its NCIB), if any, and the level thereof is uncertain. Any decision to acquire Common Shares pursuant to a share buyback will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, the Company's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions (including covenants contained in the agreements governing any indebtedness that the Company has incurred or may incur in the future, including the terms of the Credit Facilities) and satisfaction of the solvency tests imposed on the Company under applicable corporate law. There can be no assurance of the number of Common Shares that the Company will acquire pursuant to a share buyback, if any, in the future.

Baytex's future shareholder distributions, including but not limited to the payment of dividends, if any, and the level thereof is uncertain. Any decision to pay dividends on the common shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith and any special dividends) will be subject to the discretion of the Board of Directors of Baytex and may depend on a variety of factors, including, without limitation, Baytex's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on Baytex under applicable corporate law. Further, the actual amount, the declaration date, the record date and the payment date of any dividend is subject to the discretion of the Board of Directors of Baytex.

Baytex Energy Corp.
Condensed Consolidated Interim Statements of Financial Position
(thousands of Canadian dollars) (unaudited)

	Notes	As at March 31, 2026	As at December 31, 2025
ASSETS			
Current assets			
Cash	18	**$ 757,869**	$ 953,113
Trade receivables	14, 18	**194,985**	135,230
Prepaids and other assets		**32,637**	35,008
Inventory		**14,174**	—
Financial derivatives	18	**1,901**	28,898
Assets held for sale	3	**—**	38,117
		1,001,566	1,190,366
Non-current assets			
Exploration and evaluation assets	4	**141,444**	133,585
Oil and gas properties	5	**1,949,916**	1,918,435
Other plant and equipment		**7,476**	7,648
Lease assets	7	**55,229**	20,812
Prepaids and other assets	15	**26,454**	28,224
Deferred income tax asset	15	**70,607**	46,344
		$ 3,252,692	$ 3,345,414
LIABILITIES			
Current liabilities			
Trade payables	18	**$ 303,107**	$ 236,373
Share-based compensation liability	12	**22,467**	26,108
Dividends payable	11, 18	**16,606**	17,268
Financial derivatives	18	**96,876**	2,406
Liabilities related to assets held for sale	3	**—**	23,710
Lease obligations	7	**9,439**	7,175
Asset retirement obligations	10	**17,165**	17,138
		465,660	330,178
Non-current liabilities			
Share-based compensation liability	12	**3,281**	8,694
Credit facilities	8	**—**	1,138
Long-term notes	9	**87,598**	93,834
Lease obligations	7	**48,783**	15,844
Asset retirement obligations	10	**514,613**	506,677
		1,119,935	956,365
SHAREHOLDERS' EQUITY			
Shareholders' capital	11	**5,786,747**	6,072,562
Contributed surplus		**511,326**	397,681
Accumulated other comprehensive income		**13,166**	13,356
Deficit		**(4,178,482)**	(4,094,550)
		2,132,757	2,389,049
		$ 3,252,692	$ 3,345,414

Subsequent events (notes 11 and 18)

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated Interim Statements of Income (Loss) and Comprehensive Income (Loss)
(thousands of Canadian dollars, except per common share amounts and weighted average common shares) (unaudited)

		Three Months Ended March 31	
	Notes	**2026**	2025 Revised (1)
Revenue, net of royalties			
Petroleum and natural gas sales	14	**$ 452,954**	$ 454,151
Royalties		**(51,589)**	(59,256)
		401,365	394,895
Expenses			
Operating		**81,244**	75,580
Transportation		**23,134**	18,779
Blending and other		**75,921**	72,820
General and administrative		**22,299**	18,566
Exploration and evaluation	4	**665**	107
Depletion and depreciation		**123,690**	116,743
Share-based compensation	12	**22,870**	413
Net financing and interest expense	16	**3,097**	50,567
Financial derivatives loss	18	**150,756**	49,619
Foreign exchange loss (gain)	17	**1,934**	(3,878)
(Gain) loss on dispositions		**(2,017)**	1,229
Other expense		**1,704**	2,396
		505,297	402,941
Net loss before income taxes from continuing operations		**(103,932)**	(8,046)
Income taxes	15		
Current income tax expense		**—**	947
Deferred income tax (recovery) expense		**(24,253)**	8,362
		(24,253)	9,309
Net loss from continuing operations		**$ (79,679)**	$ (17,355)
Net income from discontinued operations	6	**$ 12,353**	$ 86,946
Net (loss) income		**$ (67,326)**	$ 69,591
Other comprehensive income (loss)			
Foreign currency translation adjustment		**(190)**	(8,422)
Comprehensive (loss) income		**$ (67,516)**	$ 61,169
Net (loss) income per common share			
Continuing operations - basic		**$ (0.11)**	$ (0.02)
Discontinued operations - basic		**$ 0.02**	$ 0.11
Net (loss) income per share - basic		**$ (0.09)**	$ 0.09
Continuing operations - diluted		**$ (0.11)**	$ (0.02)
Discontinued operations - diluted (2)		**$ 0.02**	$ 0.11
Net (loss) income per share - diluted		**$ (0.09)**	$ 0.09
Weighted average common shares (000's)	13		
Basic		**747,156**	771,443
Diluted (2)		**747,156**	774,257

(1) Comparative period has been revised to reflect current period presentation. See Note 6 for additional information.
(2) See Note 13 for additional information about the diluted weighted average common shares as related to discontinued operations.

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated Interim Statements of Changes in Equity
(thousands of Canadian dollars) (unaudited)

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	Total equity
Balance at December 31, 2024		$ 6,137,479	$ 361,854	$ 1,093,261	$ (3,421,584)	**$ 4,171,010**
Vesting of share awards		330	—	—	—	**330**
Repurchase of common shares for cancellation		(29,363)	16,341	—	—	**(13,022)**
Dividends declared		—	—	—	(17,289)	**(17,289)**
Comprehensive (loss) income		—	—	(8,422)	69,591	**61,169**
Balance at March 31, 2025		$ 6,108,446	$ 378,195	$ 1,084,839	$ (3,369,282)	**$ 4,202,198**
Balance at December 31, 2025		$ 6,072,562	$ 397,681	$ 13,356	$ (4,094,550)	**$ 2,389,049**
Vesting of share awards	11	688	—	—	—	**688**
Share-based compensation	12	—	4,857	—	—	**4,857**
Repurchase of common shares for cancellation	11	(286,503)	108,788	—	—	**(177,715)**
Dividends declared	11	—	—	—	(16,606)	**(16,606)**
Comprehensive loss		—	—	(190)	(67,326)	**(67,516)**
Balance at March 31, 2026		$ 5,786,747	$ 511,326	$ 13,166	$ (4,178,482)	**$ 2,132,757**

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated Interim Statements of Cash Flows
(thousands of Canadian dollars) (unaudited)

		Three Months Ended March 31	
	Notes	**2026**	2025
CASH PROVIDED BY (USED IN):			
Operating activities			
Net (loss) income		**$ (67,326)**	$ 69,591
Adjustments for:			
Non-cash share-based compensation	12	**4,857**	—
Unrealized foreign exchange loss (gain)	17	**1,630**	(3,475)
Exploration and evaluation	4	**665**	107
Depletion and depreciation		**123,690**	319,923
Non-cash financing and interest	16	**5,851**	8,459
Unrealized financial derivatives loss	18	**121,467**	49,425
(Gain) loss on dispositions		**(15,456)**	1,229
Deferred income tax (recovery) expense	15	**(24,253)**	18,611
Asset retirement obligations settled	10	**(2,619)**	(3,519)
Change in non-cash working capital		**(26,303)**	(29,034)
Cash flows from operating activities		**122,203**	431,317
Financing activities			
Decrease in credit facilities		**(1,400)**	(89,705)
Payments on lease obligations	7	**(1,789)**	(2,725)
Redemption of long-term notes	9	**(8,270)**	—
Repurchase of common shares	11	**(177,715)**	(13,022)
Dividends declared	11	**(16,606)**	(17,289)
Change in non-cash working capital		**1,817**	854
Cash flows used in financing activities		**(203,963)**	(121,887)
Investing activities			
Additions to exploration and evaluation assets	4	**(1,737)**	—
Additions to oil and gas properties	5	**(143,275)**	(405,097)
Additions to other plant and equipment		**(320)**	(559)
Consideration related to assets held for sale	3	**14,407**	—
Property acquisitions		**(8,127)**	(1,257)
Proceeds from dispositions		**13,113**	2,266
Change in non-cash working capital		**10,652**	84,573
Cash flows used in investing activities		**(115,287)**	(320,074)
Change in cash		**(197,047)**	(10,644)
January 1, 2026 opening balance prior to restatement for IFRS 9 amendments		**953,113**	16,610
Adjustment on adoption of IFRS 9 amendments for 2025 outstanding cheques on January 1, 2026	2	**1,803**	—
Cash, beginning of period		**954,916**	16,610
Cash, end of period		**$ 757,869**	$ 5,966
Supplementary information			
Interest paid		**$ 4,453**	$ 36,675
Interest received		**$ 5,445**	$ —
Income taxes paid		**$ —**	$ 5,320

See accompanying notes to the condensed consolidated interim financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the “Company” or “Baytex”) is an oil and natural gas company engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin. The Company’s common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company’s head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PREPARATION

The condensed consolidated interim financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). These consolidated financial statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with the annual consolidated financial statements as at and for the year ended December 31, 2025 ("2025 annual consolidated financial statements").

The consolidated financial statements were approved by the Board of Directors of Baytex on May 7, 2026.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company. References to “US$” are to United States ("U.S.") dollars. All financial information is rounded to the nearest thousand, except per share amounts or where otherwise indicated.

The Company's Canadian operations are presented herein as continuing operations and the disposed U.S. operations have been classified and presented as discontinued operations. A segment note is no longer presented as there is only one operating segment at period end. See Note 6 - "Discontinued Operations" for additional information.

The audited 2025 annual consolidated financial statements of the Company are available through its filings on SEDAR+ at www.sedarplus.ca and through the U.S. Securities and Exchange Commission at www.sec.gov.

Estimation Uncertainty

Management makes judgments and assumptions about the future in deriving estimates used in preparation of these consolidated financial statements in accordance with IFRS. Sources of estimation uncertainty include estimates used to determine economically recoverable oil, natural gas, and natural gas liquids reserves, the recoverable amount of long-lived assets or cash generating units, the fair value of financial derivatives, the provision for asset retirement obligations and the provision for income taxes and the related deferred tax assets and liabilities.

Environmental Reporting Regulations

Environmental reporting for public enterprises continues to evolve and the Company may be subject to additional future disclosure requirements. The International Sustainability Standards Board ("ISSB") has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Sustainability Standards Board has released voluntary standards for reporting periods starting on or after January 1, 2025 that are aligned with the ISSB release and include suggestions for Canadian-specific modifications. The Canadian Securities Administrators ("CSA") have also issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters which sets forth additional reporting requirements for Canadian Public Companies. In April 2025, the CSA announced it is pausing development of new sustainability reporting requirements to allow issuers to adapt to recent developments in the U.S. and globally. Baytex continues to monitor developments on these reporting requirements and has not yet quantified the cost to comply with these regulations.

Material Accounting Policies

The material accounting policies, critical accounting judgments and significant estimates used in these consolidated financial statements are consistent with those used in the preparation of the 2025 annual consolidated financial statements.

New Accounting Standards Adopted

Effective January 1, 2026, Baytex adopted amendments to IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* which were issued by the IASB in May 2024. The amendments further clarify the date of recognition and derecognition of financial assets and liabilities. These amendments have not had a material impact on our consolidated financial statements. The amendments have been applied retrospectively with no restatement of comparative information, in accordance with transition requirements on initial application of IFRS 9. The adjustment to the cash balance is reflected as a $1.8 million increase to the opening balance of cash in the consolidated statements of cash flows.

Future Accounting Pronouncements

IFRS 18 *Presentation and Disclosure in Financial Statements* was issued in April 2024 and replaces IAS 1 *Presentation of Financial Statements*. The Standard introduces a more defined structure to the statements of income or loss and comprehensive income or loss, including new categories of income and expenses, defined subtotals, and required disclosure of management-defined performance measures. The standard is required to be adopted retrospectively and is effective for fiscal years beginning on or after January 1, 2027, with early adoption permitted. The Company is evaluating the impact that this standard will have on the consolidated financial statements.

3. ASSETS HELD FOR SALE

In March 2025, Gibson Energy Inc. ("Gibson") and Baytex entered into a 15-year take-or-pay agreement under which Baytex constructed certain oil and gas infrastructure funded by Gibson over the period of construction. As at December 31, 2025, construction was complete, with $38.1 million of construction costs incurred, $23.3 million of advances received from Gibson and $0.4 million of construction payables outstanding. The oil and gas infrastructure assets were classified as assets held for sale at December 31, 2025 at their carrying value, which was equivalent to the fair value less costs to sell.

In February 2026, ownership transferred to Gibson upon completion and acceptance in accordance with the Construction and Conveyance Agreement. No gain or loss was recognized on transfer as the assets were sold at cost. Upon transfer of ownership, the agreement was determined to contain a lease under IFRS 16. Accordingly, the assets were recognized as a lease asset with a corresponding lease obligation measured at the present value of future lease payments over the 15-year lease term. Refer to Note 7.

4. EXPLORATION AND EVALUATION ASSETS

	March 31, 2026	December 31, 2025
Balance, beginning of period	**$ 133,585**	$ 124,355
Additions to exploration and evaluation assets	**1,737**	930
Property acquisitions	**8,080**	34,148
Divestitures	**(567)**	(8,577)
Exploration and evaluation expense	**(665)**	(5,534)
Transfer to oil and gas properties (note 5)	**(726)**	(11,737)
Balance, end of period	**$ 141,444**	$ 133,585

At March 31, 2026 and December 31, 2025, the Company assessed its exploration and evaluation assets for indicators of impairment or impairment reversal and concluded that the estimation of recoverable amount was not required for any of its cash generating units ("CGUs").

5. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2024	**$ 17,443,344**	**$ (10,522,176)**	**$ 6,921,168**
Additions to oil and gas properties	1,205,141	—	1,205,141
Property acquisitions	2,147	—	2,147
Transfers from exploration and evaluation assets (note 4)	11,737	—	11,737
Change in asset retirement obligations (note 10)	(11,311)	—	(11,311)
Divestitures	(10,838,470)	6,250,607	(4,587,863)
Impairment loss	—	(148,000)	(148,000)
Foreign currency translation	(450,006)	230,586	(219,420)
Depletion	—	(1,255,164)	(1,255,164)
Balance, December 31, 2025	**$ 7,362,582**	**$ (5,444,147)**	**$ 1,918,435**
Additions to oil and gas properties	143,275	—	143,275
Property acquisitions	47	—	47
Transfers from exploration and evaluation assets (note 4)	726	—	726
Change in asset retirement obligations (note 10)	8,397	—	8,397
Divestitures	(229)	—	(229)
Depletion	—	(120,735)	(120,735)
Balance, March 31, 2026	**$ 7,514,798**	**$ (5,564,882)**	**$ 1,949,916**

At March 31, 2026, the Company assessed its oil and gas properties for indicators of impairment or impairment reversal and concluded that the estimation of recoverable amount was not required for any of its CGUs.

At December 31, 2025, the Company identified indicators of impairment for oil and gas properties in its Viking CGU due to negative technical revisions in proved plus probable reserves. The recoverable amount for the Viking CGU was not sufficient to support its carrying value which resulted in an impairment of $148.0 million recorded at December 31, 2025. The Company identified indicators of impairment reversal for oil and gas properties in its Lloydminster CGU due to a decrease in the asset-specific discount rate. The recoverable amount for the Lloydminster CGU supported its carrying value and no impairment reversal was recorded at December 31, 2025. The recoverable amount of each CGU was based on a fair value less costs of disposal model using estimated cash flows associated with proved plus probable reserves from an independent reserve report prepared as at December 31, 2025 utilizing a discount rate based on Baytex's corporate weighted average cost of capital adjusted for asset specific factors. The after-tax discount rates applied to the cash flows were between 12% and 14%.

6. DISCONTINUED OPERATIONS

In 2025, the Company completed the disposition of the operated and non-operated assets in its Eagle Ford CGUs. The Eagle Ford CGUs represented a geographical area of the Company's operations, therefore, its results have been classified as discontinued operations in accordance with IFRS 5 *Non-current Assets Held for Sale and Discontinued Operations*.

In the three months ended March 31, 2026, the Company recorded $12.4 million of final closing adjustments.

The following table summarizes the Company's financial results from discontinued operations.

	Three Months Ended March 31	
	2026	2025
Revenue, net of royalties		
Petroleum and natural gas sales	**$ —**	$ 544,979
Royalties	**—**	(148,681)
	—	396,298
Expenses		
Operating	**—**	72,123
Transportation	**—**	11,733
General and administrative	**—**	7,040
Depletion and depreciation	**—**	203,180
Share-based compensation	**—**	350
Financing and interest	**—**	4,679
Other income	**—**	(1,207)
	—	297,898
Net income before income taxes - operations	**—**	98,400
Income taxes - operations		
Current income tax expense - operations	**—**	1,205
Deferred income tax expense - operations	**—**	10,249
	—	11,454
Net income - operations	**$ —**	$ 86,946
Gain on disposition after tax	**12,353**	—
Net income - discontinued operations	**$ 12,353**	$ 86,946

The following table summarizes cash flows from discontinued operations reported in the consolidated statements of cash flows.

	Three Months Ended March 31	
	2026	2025
Cash provided by (used in) discontinued operations:		
Operating activities	**$ —**	$ 276,226
Financing activities	**—**	(55,631)
Investing activities	**13,153**	(168,577)
Increase in cash from discontinued operations	**$ 13,153**	$ 52,018

7. LEASES

Lease Assets

Baytex had the following right-of-use assets:

	Office Leases	Field Equipment and Infrastructure	Vehicles and Other	Total
Balance, December 31, 2024	**$ 13,091**	**$ 8,243**	**$ 734**	**$ 22,068**
Additions	106	17,918	1,052	19,076
Dispositions	(2,896)	(5,865)	(8)	(8,769)
Modifications	(1,904)	4,579	(68)	2,607
Depreciation	(2,393)	(10,642)	(760)	(13,795)
Foreign currency translation	(159)	(216)	—	(375)
Balance, December 31, 2025	**$ 5,845**	**$ 14,017**	**$ 950**	**$ 20,812**
Additions	—	36,096	198	36,294
Modifications	27	732	(60)	699
Depreciation	(331)	(2,061)	(184)	(2,576)
Balance, March 31, 2026	**$ 5,541**	**$ 48,784**	**$ 904**	**$ 55,229**

Lease Obligations

Baytex had the following future commitments associated with its lease obligations:

	March 31, 2026	December 31, 2025
Less than 1 year	**$ 14,792**	$ 8,487
1 - 3 years	**22,290**	10,690
3 - 5 years	**17,823**	7,097
After 5 years	**40,741**	—
Total lease payments	**95,646**	26,274
Amounts representing interest over the term of the lease	**(37,424)**	(3,255)
Present value of net lease payments	**58,222**	23,019
Less current portion of lease obligations	**9,439**	7,175
Non-current portion of lease obligations	**$ 48,783**	$ 15,844

The Company recorded interest expense related to its lease obligations of $1.1 million and recorded lease payments, excluding interest, of $1.8 million for the three months ended March 31, 2026 ($0.3 million and $2.7 million, respectively, for the three months ended March 31, 2025).

8. CREDIT FACILITIES

	March 31, 2026	December 31, 2025
Credit facilities - U.S. dollar denominated	**$ —**	$ 1,400
Credit facilities - Canadian dollar denominated	**—**	—
Credit facilities - principal [(1)]	**$ —**	$ 1,400
Unamortized debt issuance costs	**—**	(262)
Credit facilities	**$ —**	$ 1,138

(1) The decrease in the principal amount of the credit facilities outstanding from December 31, 2025 to March 31, 2026 is the result of repayments of $1.4 million.

At March 31, 2026, Baytex had $750 million of revolving credit facilities (the "Credit Facilities") that mature on June 27, 2030. The Credit Facilities are secured and are comprised of a $50 million operating loan and a $700 million syndicated revolving loan.

The Credit Facilities contain standard commercial covenants, in addition to the financial covenants detailed below, related to debt incurrence, restricted payments, certain transactions and compliance with applicable laws. Noncompliance with these covenants may result in an event of default, at which point the carrying value of the debt could become repayable within a 12-month period after the reporting date. Baytex continues to be in compliance with all financial and commercial covenants under its debt agreements.

Advances under the Baytex Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, Canadian Overnight Repo Rate Average rates or Secured Overnight Financing Rates, plus applicable margins.

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at March 31, 2026.

Covenant Description	**Position as at March 31, 2026**	**Covenant**
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0:0:1.0**	**3.5:1.0**
Interest Coverage (3) (Minimum Ratio)	**5.5:1.0**	**3.5:1.0**
Total Debt (4) to Bank EBITDA (2) (Maximum Ratio)	**0.1:1.0**	**4.0:1.0**

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at March 31, 2026, the Company's Senior Secured Debt totaled $4.4 million.
(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility agreement which adjusts net income or loss for financing and interest expense, income taxes, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material dispositions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended March 31, 2026 was $661.0 million.
(3) "Interest coverage" is calculated in accordance with the credit facility agreement and is computed as the ratio of Bank EBITDA to financing and interest expense, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis including the impact of material dispositions as if they had occurred at the beginning of the twelve month period. Financing and interest expense for the twelve months ended March 31, 2026 was $119.4 million.
(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade payables, share-based compensation liability, dividends payable, asset retirement obligations, lease obligations, deferred income tax liability, and financial derivative liabilities. As at March 31, 2026, the Company's Total Debt totaled $93.9 million of principal amounts outstanding.

At March 31, 2026, Baytex had $4.4 million of outstanding letters of credit (December 31, 2025 - $4.4 million outstanding) under the Credit Facilities.

9. LONG-TERM NOTES

	March 31, 2026	December 31, 2025
7.375% notes due March 15, 2032 (1)	**$ 89,507**	$ 95,947
Unamortized debt issuance costs	**(1,909)**	(2,113)
Total long-term notes - net of unamortized debt issuance costs	**$ 87,598**	$ 93,834

(1) The U.S. dollar denominated principal outstanding of the 7.375% notes was US$64.1 million as at March 31, 2026 (December 31, 2025 - US$70.0 million). The decrease in the principal amount outstanding from December 31, 2025 to March 31, 2026 is the result of the repurchase and cancellation of US$5.8 million ($8.0 million) and changes in the reported amount of U.S. denominated debt of $1.5 million due to changes in the CAD/USD exchange rate used to translate the U.S. denominated amount of long-term notes outstanding.

The long-term notes do not contain any significant financial maintenance covenants but do contain standard commercial covenants for debt incurrence and restricted payments.

During the three months ended March 31, 2026, Baytex repurchased and cancelled US$5.8 million principal amount of the 7.375% Senior Notes at 103.613% of par value and recorded an early redemption expense of $0.3 million.

10. ASSET RETIREMENT OBLIGATIONS

	March 31, 2026	December 31, 2025
Balance, beginning of period	**$ 523,815**	$ 640,951
Liabilities incurred (1)	**4,790**	20,794
Liabilities settled	**(2,619)**	(20,318)
Liabilities divested	**(2,853)**	(104,223)
Accretion (note 16)	**5,038**	23,012
Change in estimate (1)	**827**	(7,442)
Changes in discount and inflation rates (1)(2)	**2,780**	(24,663)
Foreign currency translation	**—**	(4,296)
Balance, end of period	**$ 531,778**	$ 523,815
Less current portion of asset retirement obligations	**17,165**	17,138
Non-current portion of asset retirement obligations	**$ 514,613**	$ 506,677

(1) The total of these items reflects the total change in asset retirement obligations of $8.4 million per Note 5 - Oil and Gas Properties ($11.3 million decrease in 2025).

(2) The discount and inflation rates used to calculate the liability at March 31, 2026 were 3.9% and 2.1% respectively (December 31, 2025 - 3.9% and 2.0%). The discount and inflation rates used prior to the closing of the sale of our U.S. operations on December 19, 2025 were 4.8% and 2.3%, respectively.

11. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at March 31, 2026, no preferred shares have been issued by the Company and all common shares issued were fully paid. The holders of common shares may receive dividends as declared from time to time and are entitled to one vote per share at any meeting of the holders of common shares. All common shares rank equally with regard to the Company's net assets in the event the Company is wound-up or terminated.

	Number of Common Shares (000s)	Amount
Balance, December 31, 2024	**773,590**	**$ 6,137,479**
Vesting of share awards	112	330
Common shares repurchased and cancelled	(8,134)	(65,247)
Balance, December 31, 2025	**765,568**	**$ 6,072,562**
Vesting of share awards	125	688
Common shares repurchased and cancelled	(35,132)	(286,503)
Balance, March 31, 2026	**730,561**	**$ 5,786,747**

Normal Course Issuer Bid ("NCIB") Share Repurchases

On June 24, 2025, Baytex announced that the TSX accepted the renewal of the NCIB under which Baytex is permitted to purchase for cancellation up to 66.2 million common shares over the 12-month period commencing July 2, 2025, which represents 10% of the Company's public float, as defined by the TSX, as at June 18, 2025. Baytex obtained an exemption order from the Canadian securities regulators which permits the company to purchase its common shares through the NYSE and other U.S.-based trading systems. On June 18, 2025, Baytex had 768.3 million common shares outstanding. At March 31, 2026, we had 28.4 million shares remaining on our NCIB which expires on July 2, 2026.

During the three months ended March 31, 2026, Baytex recorded $177.7 million related to common share repurchases, which includes $174.3 million of consideration paid for the repurchase and cancellation of common shares as well as $3.4 million of federal tax levied on common share repurchases.

Purchases are made on the open market at prices prevailing at the time of the transaction. During the three months ended March 31, 2026, Baytex repurchased and cancelled 35.1 million common shares at an average price of $4.96 per share for total consideration of $174.3 million. During 2025, Baytex repurchased and cancelled 8.1 million common shares at an average price of $3.55 per share for total consideration of $28.9 million. The total consideration paid includes the commissions and fees paid as part of the transaction and is recorded as a reduction to shareholders' equity. The shares repurchased and cancelled are accounted for as a reduction in shareholders' capital at historical cost, with any discount paid recorded to contributed surplus and any premium paid recorded to retained earnings.

During the three months ended March 31, 2026, Baytex recorded a $3.4 million liability related to the 2% federal tax on equity repurchases (December 31, 2025 - $0.5 million), which is charged to shareholders' capital.

Dividends

On January 2 and April 1, 2026, we paid a quarterly cash dividend of $0.0225 per share to shareholders of record. On May 7, 2026, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on July 2, 2026 to shareholders of record on June 15, 2026.

12. SHARE-BASED COMPENSATION PLAN

For the three months ended March 31, 2026 the Company recorded share-based compensation expense for continuing operations of $22.9 million which includes $18.0 million of cash compensation expense related to cash-settled awards and $4.9 million of non-cash compensation expense related to certain awards designated as equity-settled. For the three months ended March 31, 2025, the Company recorded share-based compensation expense of $0.4 million for continuing operations and $0.4 million for discontinued operations which was related to cash-settled awards.

The Company's closing share price on the TSX on March 31, 2026 was $6.22 (December 31, 2025 - $4.44 and March 31, 2025 - $3.19).

Share Award Incentive Plan

Baytex has a Share Award Incentive Plan pursuant to which it issues restricted and performance awards. A restricted award entitles the holder of each award to receive one common share of Baytex or the equivalent cash value per restricted award at the time of vesting. A performance award entitles the holder of each award to receive between zero and two common shares or the equivalent cash value on vesting; the number of common shares issued is determined by a performance multiplier. The multiplier can range between zero and two and is calculated based on a number of factors determined and approved by the Human Resources and Compensation Committee of the Board of Directors on an annual basis. The Share Awards vest in equal tranches on the first, second and third anniversaries of the grant date. The cumulative expense is recognized at fair value at each period end and is included in share-based compensation liability.

The weighted average fair value of share awards granted during the three months ended March 31, 2026 was $5.50 per restricted and performance award ($2.93 for the three months ended March 31, 2025).

Incentive Award Plan

Baytex has an Incentive Award Plan whereby the participants of the plan are entitled to receive a cash payment equal to the value of one Baytex common share per incentive award at the time of vesting. The incentive awards vest in equal tranches on the first, second and third anniversaries of the grant date. The cumulative expense is recognized at fair value at each period end and is included in share-based compensation liability.

The weighted average fair value of share awards granted during the three months ended March 31, 2026 was $5.50 per incentive award ($2.93 for the three months ended March 31, 2025).

Deferred Share Unit Plan ("DSU Plan")

Baytex has a DSU Plan whereby each independent director of Baytex is entitled to receive a cash payment equal to the value of one Baytex common share per DSU award on the date at which they cease to be a member of the Board. The awards vest immediately upon being granted and are expensed in full on the grant date. The units are recognized at fair value at each period end and are included in share-based compensation liability.

The weighted average fair value of share awards granted during the three months ended March 31, 2026 was $5.50 per DSU award ($2.93 for the three months ended March 31, 2025).

The number of awards outstanding is detailed below:

(000s)	Restricted awards	Performance awards	Incentive awards	DSU awards	Total
Total, December 31, 2024	**826**	**3,482**	**5,275**	**1,418**	**11,001**
Granted	5	3,905	5,927	528	10,365
Forfeited by performance factor	—	(243)	—	—	(243)
Vested	(804)	(2,113)	(3,798)	—	(6,715)
Forfeited	(4)	(191)	(1,952)	—	(2,147)
Total, December 31, 2025	**23**	**4,840**	**5,452**	**1,946**	**12,261**
Granted	—	1,246	1,700	49	2,995
Added by performance factor	—	269	—	—	269
Vested	(23)	(2,414)	(2,356)	(124)	(4,917)
Forfeited	—	(28)	(191)	—	(219)
Total, March 31, 2026	**—**	**3,913**	**4,605**	**1,871**	**10,389**

13. PER SHARE AMOUNTS

Baytex calculates basic income or loss per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted to common shares. The treasury stock method is used to determine the dilutive effect of share awards whereby the potential conversion of share awards and the amount of compensation expense, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the period.

The following table summarizes the weighted average common shares used in calculating net income or loss per share.

	Three Months Ended March 31	
(000s)	**2026** (1)	2025
Weighted average common shares - basic	**747,156**	771,443
Dilutive effect of share-based compensation	**—**	2,814
Weighted average common shares - diluted	**747,156**	774,257

(1) No share awards were excluded from the calculation of diluted income per share for discontinued operations. The dilutive effect of share-based compensation is 4.1 million shares in the calculation of diluted net income per share for discontinued operations.

For the three months ended March 31, 2026, all share awards were excluded from the calculation of diluted loss per share as their effect was anti-dilutive given the Company recorded a loss. For the three months ended March 31, 2025, no share awards were excluded from the calculation of diluted income per share.

14. PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas sales from contracts with customers for the Company's continuing and discontinued operations is set forth in the following table.

	Three Months Ended March 31	
	2026	2025 (1)
Light oil and condensate	**$ 88,993**	$ 99,469
Heavy oil	**346,737**	338,711
NGL	**8,560**	7,888
Natural gas	**8,664**	8,083
Total petroleum and natural gas sales - continuing operations	**$ 452,954**	$ 454,151
Total petroleum and natural gas sales - discontinued operations	**$ —**	$ 544,979

(1) Comparative period has been revised to reflect current period presentation. See Note 6 for additional information.

Included in trade receivables at March 31, 2026 is $168.6 million of accrued receivables related to delivered volumes (December 31, 2025 - $102.3 million).

15. INCOME TAXES

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency ("CRA") that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. Following objections and submissions, in November 2023 the CRA issued notices of confirmation regarding their prior reassessments. In February 2024, Baytex filed notices of appeal with the Tax Court of Canada (“TCC”) and we estimate it could take another two to three years to receive a judgment. The reassessments do not require us to pay any amounts in order to participate in the appeals process. Should we be unsuccessful at the TCC, additional appeals are available; a process that we estimate could take another two years and potentially longer.

We remain confident that the tax filings of the affected entities are correct and will defend our tax filing positions. During 2023, we purchased $272.5 million of insurance coverage for a premium of $50.3 million which will help manage the litigation risk associated with this matter. The most recent statement of account issued by the CRA assert taxes owing by the trusts of $244.8 million, late payment interest of $244.2 million and a late filing penalty in respect of the 2011 tax year of $4.1 million.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591.0 million (the "Losses"). The Losses were subsequently deducted in computing the taxable income of those trusts. The reassessments, as confirmed in November 2023, disallow the deduction of the Losses for two reasons. First, the reassessments allege that the trusts were resettled and the resulting successor trusts were not able to access the losses of the predecessor trusts. Second, the reassessments allege that the general anti-avoidance rule of the Income Tax Act (Canada) operates to deny the deduction of the losses. In September 2025, the Department of Justice, legal counsel for the Crown, abandoned the position that the trusts were resettled. The issue of whether the general anti-avoidance rule applies remains in dispute. If, after exhausting available appeals, the deduction of the Losses continues to be disallowed, either the trusts or their corporate beneficiary will owe cash taxes, late payment interest and potential penalties. The amount of cash taxes owing, late payment interest and potential penalties are dependent upon the taxpayer(s) ultimately liable (the trusts or their corporate beneficiary) and the amount of unused tax shelter available to the taxpayer(s) to offset the reassessed income, including tax shelter from subsequent years that may be carried back and applied to prior years.

16. NET FINANCING AND INTEREST EXPENSE

	Three Months Ended March 31	
	2026	2025 (1)
Interest on Credit Facilities	**$ 887**	$ 3,337
Interest on long-term notes	**1,719**	40,279
Interest on lease obligations	**1,095**	325
Interest income	**(6,455)**	(350)
Net cash interest (income) expense	**$ (2,754)**	$ 43,591
Amortization of debt issue costs	**516**	2,378
Accretion on asset retirement obligations (note 10)	**5,038**	4,598
Early redemption expense	**297**	—
Net financing and interest expense - continuing operations	**$ 3,097**	$ 50,567
Net financing and interest expense - discontinued operations	**$ —**	$ 4,679

(1) Comparative period has been revised to reflect current period presentation. See Note 6 for additional information.

17. FOREIGN EXCHANGE

	Three Months Ended March 31	
	2026	2025
Unrealized foreign exchange loss (gain)	**$ 1,630**	$ (3,475)
Realized foreign exchange loss (gain)	**304**	(403)
Foreign exchange loss (gain) - continuing operations	**$ 1,934**	$ (3,878)

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade receivables, trade payables, dividends payable, financial derivatives, Credit Facilities and long-term notes. The fair value of cash, trade receivables, trade payables and dividends payable approximates carrying value due to the short term to maturity. The fair value of the Credit Facilities is equal to the principal amount outstanding as the Credit Facilities bear interest at floating rates and credit spreads that are indicative of market rates. The fair value of the long-term notes is determined based on market prices. The fair value of the financial derivatives is based on quoted market prices or, in their absence, third-party market indications and forecasts.

The carrying value and fair value of the Company's financial instruments carried on the condensed consolidated statements of financial position are classified into the following categories:

	March 31, 2026		December 31, 2025		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
Fair value through profit and loss					
Financial derivatives	**$ 1,901**	**$ 1,901**	$ 28,898	$ 28,898	Level 2
Total	**$ 1,901**	**$ 1,901**	$ 28,898	$ 28,898	
Amortized cost					
Cash	**$ 757,869**	**$ 757,869**	$ 953,113	$ 953,113	—
Trade receivables	**194,985**	**194,985**	135,230	135,230	—
Total	**$ 952,854**	**$ 952,854**	$ 1,088,343	$ 1,088,343	
Financial Liabilities					
Fair value through profit and loss					
Financial derivatives	**$ (96,876)**	**$ (96,876)**	$ (2,406)	$ (2,406)	Level 2
Total	**$ (96,876)**	**$ (96,876)**	$ (2,406)	$ (2,406)	
Amortized cost					
Trade payables	**$ (303,107)**	**$ (303,107)**	$ (236,373)	$ (236,373)	—
Dividends payable	**(16,606)**	**(16,606)**	(17,268)	(17,268)	—
Credit Facilities (1)	**—**	**—**	(1,138)	(1,400)	—
Long-term notes	**(87,598)**	**(92,744)**	(93,834)	(99,808)	Level 1
Total	**$ (407,311)**	**$ (412,457)**	$ (348,613)	$ (354,849)	

(1) The difference in the carrying value and fair value of the Credit Facilities is due to unamortized debt issuance costs. Refer to Note 8.

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2026 and 2025.

Foreign Currency Risk

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities recorded in entities with a Canadian dollar functional currency at the reporting date are as follows:

	Assets		Liabilities	
	March 31, 2026	December 31, 2025	**March 31, 2026**	December 31, 2025
U.S. dollar denominated	**US$11,255**	US$22,204	**US$160,482**	US$84,500

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following commodity financial derivative contracts outstanding as at May 7, 2026.

	Remaining Period	Volume	Price/Unit (1)	Index
Oil				
Basis differential	Apr 2026 to Jun 2026	2,500 bbl/d	WTI less US$12.55/bbl	WCS
Basis differential	Jul 2026 to Sep 2026	2,500 bbl/d	WTI less US$13.05/bbl	WCS
Basis differential	Apr 2026 to Dec 2026	19,500 bbl/d	WTI less US$13.13/bbl	WCS
Basis differential	Oct 2026 to Dec 2026	2,500 bbl/d	WTI less US$13.75/bbl	WCS
Basis differential	Apr 2026 to Jun 2026	1,000 bbl/d	WTI less US$3.75/bbl	MSW
Basis differential	Jul 2026 to Sep 2026	1,000 bbl/d	WTI less US$3.50/bbl	MSW
Basis differential	Oct 2026 to Dec 2026	1,000 bbl/d	WTI less US$4.25/bbl	MSW
Basis differential	Apr 2026 to Sep 2026	3,000 bbl/d	WTI less US$2.70/bbl	MSW
Put option (2)	Apr 2026 to Jun 2026	2,000 bbl/d	US$60.00/bbl	WTI
Call option (2)	Apr 2026 to Jun 2026	2,000 bbl/d	US$70.00/bbl	WTI
Collar	Apr 2026 to Jun 2026	5,000 bbl/d	US$60.00/US$67.00/bbl	WTI
Collar	Apr 2026 to Apr 2026	2,500 bbl/d	US$60.00/US$68.00/bbl	WTI
Collar	Apr 2026 to Jun 2026	5,000 bbl/d	US$60.00/US$66.00/bbl	WTI
Collar	Apr 2026 to Jun 2026	5,000 bbl/d	US$60.00/US$64.00/bbl	WTI
Collar	Apr 2026 to Jun 2026	5,000 bbl/d	US$60.00/US$65.00/bbl	WTI
Collar	Apr 2026 to Jun 2026	2,500 bbl/d	US$60.00/US$68.00/bbl	WTI
Natural Gas				
Swap	Apr 2026 to Dec 2026	2,000 GJ/d	$3.21/GJ	AECO
Swap (3)	May 2026 to Dec 2026	7,000 GJ/d	$1.64/GJ	AECO
Basis differential	Apr 2026 to Dec 2026	2,500 mmbtu/d	NYMEX less US$1.66/mmbtu	NYMEX/AECO
Collar	Apr 2026 to Dec 2026	2,500 mmbtu/d	US$4.00/US$5.10/mmbtu	NYMEX

(1) Based on the weighted average price per unit for the period.
(2) Contracts include deferred premiums to be paid throughout the contract term. The net weighted average deferred premium receivable is US$0.01/bbl.
(3) Contract entered subsequent to March 31, 2026.

The following table sets forth the realized and unrealized gains and losses recorded on financial derivatives.

	Three Months Ended March 31	
	2026	2025
Realized financial derivatives loss	**$ 29,289**	$ 194
Unrealized financial derivatives loss	**121,467**	49,425
Financial derivatives loss	**$ 150,756**	$ 49,619

19. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain a strong financial position that provides flexibility to execute its development programs, provide returns to shareholders and optimize its portfolio through strategic acquisitions. Baytex assesses its capital structure in response to operational requirements and changes in economic conditions. At March 31, 2026, the Company's capital structure was comprised of shareholders' capital, long-term notes, trade receivables, prepaids and other assets, inventory, trade payables, share-based compensation liability, dividends payable, cash and the Credit Facilities.

In order to manage its capital structure and liquidity, Baytex may from time-to-time issue or repurchase equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

The capital-intensive nature of Baytex's operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Baytex's capital resources consist primarily of adjusted funds flow, available Credit Facilities and proceeds received from the divestiture of oil and gas properties. The following capital management measures and ratios are used to monitor current and projected sources of liquidity.

Net Cash

The Company uses net cash to monitor its current financial position and to evaluate existing sources of liquidity. The Company defines net cash to be the sum of our Credit Facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade payables, dividends payable, share-based compensation liability, other long-term liabilities, cash, trade receivables, prepaids and other assets, and inventory. Baytex also uses net cash projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations.

The following table reconciles net cash to amounts disclosed in the primary financial statements.

	March 31, 2026	December 31, 2025
Credit Facilities	$ —	$ 1,138
Unamortized debt issuance costs - Credit Facilities (note 8)	—	262
Long-term notes	87,598	93,834
Unamortized debt issuance costs - Long-term notes (note 9)	1,909	2,113
Trade payables	303,107	236,373
Share-based compensation liability	25,748	34,802
Dividends payable	16,606	17,268
Cash	(757,869)	(953,113)
Trade receivables	(194,985)	(135,230)
Prepaids and other assets	(59,091)	(63,232)
Inventory	(14,174)	—
Net Cash	$ (591,151)	$ (765,785)

Adjusted Funds Flow

Adjusted funds flow is used to monitor operating performance and the Company's ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital and asset retirements obligations settled during the applicable period.

Adjusted funds flow is reconciled to amounts disclosed in the primary financial statements in the following table.

	Three Months Ended March 31	
	2026	2025
Cash flows from operating activities	$ 122,203	$ 431,317
Change in non-cash working capital	26,303	29,034
Asset retirement obligations settled	2,619	3,519
Adjusted Funds Flow	$ 151,125	$ 463,870

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrel of oil equivalent
boe/d	barrel of oil equivalent per day
COSO	Committee of Sponsoring Organizations of the Treadway Commission
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standards
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LLS	Louisiana Light Sweet
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

* *Oil equivalent amounts may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 Mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

Corporate
Information

Board of Directors

Mark R. Bly
Chair of the Board

Chad E. Lundberg
Director

Trudy M. Curran [2,4]
Director

Don G. Hrap [1,3]
Director

Jennifer A. Maki [1,2]
Director

David L. Pearce [2,3]
Director

Steve D.L. Reynish [1,4]
Director

Jeffrey E. Wojahn [3,4]
Director

(1) Member of the Audit Committee
(2) Member of the Human Resources and Compensation Committee
(3) Member of the Reserves and Sustainability Committee
(4) Member of the Nominating and Governance Committee

Officers

Chad E. Lundberg
President and Chief Executive Officer

Chad L. Kalmakoff
Chief Financial Officer

Kendall D. Arthur
Chief Operating Officer

James R. Maclean
Senior Vice President,
Commercial and General Counsel

Brian G. Ector
Senior Vice President,
Capital Markets and Investor Relations

Nicole M. Frechette
Vice President,
Light Oil

Adrian Blazevic
Vice President,
Heavy Oil

Chris Lessoway
Vice President,
Finance and Treasurer

Auditors
KPMG LLP

Reserves Engineers
McDaniel & Associates
Consultants Ltd.

Transfer Agent
Odyssey Trust Company

Exchange Listing
New York Stock Exchange
Toronto Stock Exchange
Symbol: **BTE**

Head Office

Baytex Energy Corp.
Centennial Place, East Tower
2800, 520 - 3rd Avenue SW
Calgary, Alberta T2P 0R3

Toll-free 1.800.524.5521
T 587.952.3000
F 587.952.3001

BAYTEXENERGY.COM

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