Q2 Report
2026

BAYTEX

BAYTEX ANNOUNCES SECOND QUARTER 2026 RESULTS; PRODUCTION GUIDANCE RAISED ON STRONG DUVERNAY AND PEAVINE PERFORMANCE; BOARD APPOINTMENTS ANNOUNCED

CALGARY, ALBERTA (July 30, 2026) - Baytex Energy Corp. ("Baytex" or the "Company") (TSX:BTE) (NYSE:BTE) reports its operating and financial results for the three and six months ended June 30, 2026 (all amounts are in Canadian dollars unless otherwise noted).

"Baytex delivered strong second-quarter results, highlighted by outperformance in the Duvernay and continued strength across our heavy oil portfolio," said Chad Lundberg, President and Chief Executive Officer. “Production exceeded the high end of guidance for the second consecutive quarter, and we are raising our full-year production guidance with no change to our capital program. Momentum continues to build as our teams execute our strategy while delivering strong operating and financial results."

Second Quarter Highlights

- Delivered production of 71,243 boe/d (88% oil and NGL), surpassing the high end of annual guidance and representing 11% growth relative to the second quarter of 2025.
- Full-year production raised to approximately 71,000 boe/d, a 1,000 boe/d increase from the mid-point of prior guidance, with exploration and development expenditures unchanged at approximately $625 million.
- Generated adjusted funds flow[1] of $254 million ($0.35 per basic share) and cash flows from operating activities of $231 million ($0.32 per basic share).
- Reported net income from continuing operations of $169 million ($0.23 per basic share).
- Generated free cash flow[2] of $128 million ($0.18 per basic share) after exploration and development expenditures of $122 million.
- Repurchased 22 million common shares for $136 million, representing 3.0% of shares outstanding;
- Exited the second quarter with net cash[1] of $566 million, maintaining an industry-leading balance sheet.

(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.

2026 Outlook

Supported by strong well performance, annual production guidance has been increased to approximately 71,000 boe/d, representing 8% annual production growth in 2026 and a target exit rate of approximately 72,000 boe/d in Q4. The updated production guidance is driven by outperformance from our first Gilby Duvernay pad along with strong results across our heavy oil portfolio, where new well performance at Peavine exceeded internal expectations. Disciplined execution of our capital programs remains a priority, with exploration and development expenditures guidance unchanged at approximately $625 million.

	Three Months Ended			Six Months Ended	
	June 30, 2026	March 31, 2026	June 30, 2025	**June 30, 2026**	June 30, 2025
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales - Canada	**$ 639,943**	$ 452,954	$ 411,036	**$ 1,092,897**	$ 865,187
Adjusted funds flow (1)	**254,433**	151,125	366,919	**405,558**	830,789
Per share – basic	**0.35**	0.20	0.48	**0.55**	1.08
Per share – diluted	**0.35**	0.20	0.48	**0.55**	1.07
Free cash flow (2)	**128,045**	1,705	3,188	**129,750**	55,717
Per share – basic	**0.18**	—	—	**0.18**	0.07
Per share – diluted	**0.18**	—	—	**0.18**	0.07
Cash flows from operating activities	**230,852**	122,203	354,312	**353,055**	785,629
Per share – basic	**0.32**	0.16	0.46	**0.48**	1.02
Per share – diluted	**0.32**	0.16	0.46	**0.48**	1.02
Net (loss) income	**174,869**	(67,326)	151,549	**107,543**	221,140
Per share – basic	**0.24**	(0.09)	0.20	**0.15**	0.29
Per share – diluted	**0.24**	(0.09)	0.20	**0.15**	0.29
Dividends declared	**16,144**	16,606	17,304	**32,750**	34,593
Per share	**0.0225**	0.0225	0.0225	**0.0450**	0.0450
Capital Expenditures					
Exploration and development expenditures	**$ 122,242**	$ 145,012	$ 356,532	**$ 267,254**	$ 761,629
Acquisitions and (divestitures)	**(5,893)**	(4,986)	468	**(10,879)**	(541)
Total oil and natural gas capital expenditures	**$ 116,349**	$ 140,026	$ 357,000	**$ 256,375**	$ 761,088
Net (Cash) Debt					
Credit facilities	**$ —**	$ —	$ 333,516	**$ —**	$ 333,516
Long-term notes	**91,107**	89,507	1,817,707	**91,107**	1,817,707
Total debt (3)	**91,107**	89,507	2,151,223	**91,107**	2,151,223
Working capital (surplus) deficiency (2)	**(657,393)**	(680,658)	142,717	**(657,393)**	142,717
Net (cash) debt (1)	**$ (566,286)**	$ (591,151)	$ 2,293,940	**$ (566,286)**	$ 2,293,940
Shares Outstanding - basic (thousands)					
Weighted average	**721,197**	747,156	768,717	**734,105**	770,072
End of period	**708,888**	730,561	768,717	**708,888**	768,717
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 92.79**	$ 71.93	$ 63.74	**$ 82.36**	$ 67.58
Edmonton par ($/bbl)	**132.26**	93.50	84.15	**112.88**	89.71
Edmonton par differential to WTI (US$/bbl)	**2.80**	(3.76)	(2.94)	**(0.42)**	(3.93)
WCS heavy oil ($/bbl)	**108.16**	79.28	74.10	**93.66**	79.15
WCS differential to WTI (US$/bbl)	**(14.62)**	(14.13)	(10.20)	**(14.37)**	(11.43)
Natural gas					
NYMEX (US$/MMbtu)	**$ 2.90**	$ 5.04	$ 3.44	**$ 3.97**	$ 3.55
AECO ($/Mcf)	**1.51**	2.49	2.07	**2.00**	2.05
CAD/USD average exchange rate	**1.3836**	1.3716	1.3840	**1.3776**	1.4095

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			Six Months Ended	
	June 30, 2026	March 31, 2026	June 30, 2025	**June 30, 2026**	June 30, 2025
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**12,236**	11,835	11,167	**12,036**	11,469
Heavy oil (bbl/d)	**46,349**	44,908	42,959	**45,632**	41,583
NGL (bbl/d)	**4,409**	4,368	2,986	**4,389**	3,054
Total liquids (bbl/d)	**62,994**	61,111	57,112	**62,057**	56,106
Natural gas (Mcf/d)	**49,502**	50,205	42,331	**49,851**	43,033
Total Canada (boe/d) (1)	**71,243**	69,478	64,167	**70,366**	63,279
Discontinued operations (boe/d) (1)	**—**	—	83,928	**—**	82,877
Oil equivalent (boe/d) (1)	**71,243**	69,478	148,095	**70,366**	146,156
Adjusted Funds Flow (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 564,875**	$ 377,033	$ 348,655	**$ 941,908**	$ 729,986
Royalties	**(90,378)**	(51,589)	(47,800)	**(141,967)**	(107,056)
Operating expense	**(89,843)**	(81,244)	(88,035)	**(171,087)**	(163,615)
Transportation expense	**(25,932)**	(23,134)	(20,544)	**(49,066)**	(39,323)
Operating netback - Canada (2)	**$ 358,722**	$ 221,066	$ 192,276	**$ 579,788**	$ 419,992
General and administrative expense	**(16,480)**	(22,299)	(16,595)	**(38,779)**	(35,161)
Net cash interest income (expense)	**702**	2,754	(41,480)	**3,456**	(85,071)
Realized financial derivatives (loss) gain	**(84,146)**	(29,289)	(11,874)	**(113,435)**	(12,068)
Other (3)	**(4,365)**	(20,021)	(9,810)	**(24,386)**	(13,163)
Adjusted funds flow - Canada (4)	**$ 254,433**	$ 152,211	$ 112,517	**$ 406,644**	$ 274,529
Adjusted funds flow - Discontinued operations (4)	**—**	(1,086)	254,402	**(1,086)**	556,260
Adjusted funds flow (4)	**$ 254,433**	$ 151,125	$ 366,919	**$ 405,558**	$ 830,789
Adjusted Funds Flow (per boe)					
Total sales, net of blending and other expense (2)	**$ 87.13**	$ 60.30	$ 59.71	**$ 73.96**	$ 63.74
Royalties (5)	**(13.94)**	(8.25)	(8.19)	**(11.15)**	(9.35)
Operating expense (5)	**(13.86)**	(12.99)	(15.08)	**(13.43)**	(14.29)
Transportation expense (5)	**(4.00)**	(3.70)	(3.52)	**(3.85)**	(3.43)
Operating netback - Canada (2)	**$ 55.33**	$ 35.36	$ 32.92	**$ 45.53**	$ 36.67
General and administrative expense (5)	**(2.54)**	(3.57)	(2.84)	**(3.04)**	(3.07)
Net cash interest income (expense) (5)	**0.11**	0.44	(7.10)	**0.27**	(7.43)
Realized financial derivatives (loss) gain (5)	**(12.98)**	(4.68)	(2.03)	**(8.91)**	(1.05)
Other (3)(5)	**(0.67)**	(3.20)	(1.68)	**(1.91)**	(1.15)
Adjusted funds flow - Canada (4)	**$ 39.25**	$ 24.35	$ 19.27	**$ 31.94**	$ 23.97
Adjusted funds flow - Discontinued operations (4)	**—**	—	33.31	**—**	37.08
Adjusted funds flow (4)	**$ 39.25**	$ 24.17	$ 27.23	**$ 31.84**	$ 31.40

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 Q2/2026 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.

Second Quarter 2026 Results

Q2 production exceeds guidance

Second quarter results were highlighted by outperformance across our light and heavy oil portfolio. Production of 71,243 boe/d (88% oil and NGL) exceeded the high end of our annual guidance range of 69,000 to 71,000 boe/d. Exploration and development expenditures of $122 million were consistent with our full-year plan.

Adjusted funds flow[1] of $254 million ($0.35 per basic share) includes $85 million of realized derivatives losses on oil contracts put in place at lower prices prior to the sale of our U.S. operations, we have no WTI hedges in place after Q2/2026. Disciplined execution of our capital program resulted in free cash flow[2] of $128 million ($0.18 per basic share). We generated net income of $175 million ($0.24 per basic share) in the second quarter.

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

The first Duvernay pad (four wells) of 2026 was brought onstream in June and outperformed internal expectations. This was the first pad brought onstream on our new Gilby acreage to the south of our Pembina lands. The wells are amongst our strongest performing wells in the Duvernay to-date on a length normalized basis. Three of the wells delivered 30-day initial production rates of 1,630 boe/d per well (1,112 bbl/d of oil, 319 bbl/d of NGLs and 1,195 mcf/d of natural gas). The fourth well was completed at half the planned lateral length after the bottom hole assembly became stuck during drilling and was unrecoverable. This well delivered a 30-day initial production rate of 866 boe/d (537 bbl/d of oil, 202 bbl/d of NGLs and 759 mcf/d of natural gas). Results from Gilby support expectations of a high-quality reservoir and increase confidence in future development on our southern acreage.

Drilling operations are complete on the second Duvernay pad of our 2026 program, located on our northern Pembina acreage. Completion operations are underway and the pad is planned to be brought onstream in September. Our 2026 Duvernay program includes a total of 17 wells drilled and 13 wells brought onstream with the remaining 4 wells onstream in 2027.

Continued heavy oil outperformance with active second half program

Second quarter operating results reflect strong performance at Peavine, Peace River, and across the broader Mannville group in Lloydminster. A total of 14 wells were brought onstream; seven Clearwater wells at Peavine and seven wells at Lloydminster.

At Peavine, outperformance continued during the second quarter with six of the new wells brought onstream establishing 30-day initial production rates that average 478 bbl/d per well.

Heavy oil development activity has ramped following spring breakup, with four rigs running across our Peavine, Peace River and Lloydminster regions. A fifth rig is scheduled to begin drilling operations in August at Morinville. In total, the 2026 program is expected to bring 99.3 net heavy oil wells on stream during 2026 with 58 net wells expected to be brought onstream during Q3 and Q4.

Clearwater waterflood and additional pilots planned

Waterflood potential in the Clearwater is being evaluated to increase resource recovery and lower our sustaining capital requirements. Both initial waterflood pilots at Peavine are currently on injection. One of the pilots is designed to test reservoir repressurization through producer to injector conversion and the second pilot is testing pressure maintenance on new development.

The waterflood pilot will be expanded in the second half of 2026 with two additional patterns at Peavine and a waterflood test in the Rex formation (a Clearwater equivalent) at Morinville. These additional pilots are included in third quarter development plans and are expected to be on injection by the fourth quarter.

Heavy oil exploration at Peace River

A 21-square-mile seismic survey was recently completed covering 20% of our 109 sections of prospective lands at Utikuma in the Peace River region. Initial interpretations are encouraging and we are preparing to drill up to two exploration test wells in early 2027.

Delivering Shareholder Returns

During the second quarter, $152 million was returned to shareholders. A total of 22 million common shares were repurchased for $136 million, at an average price of $6.27 per share, and we paid a quarterly cash dividend of $16 million ($0.225 per share). Since the disposition of our U.S. business in December 2025 through July 29, 2026, we repurchased 69 million common shares for $378 million, representing 9% of our shares outstanding, at an average price of $5.46 per share.

On June 26, 2026, we announced the renewal of our Normal Course Issuer Bid ("NCIB") with the Toronto Stock Exchange for a share buyback program for up to 10% of our public float. The renewed NCIB allows Baytex to purchase up to 70.9 million common shares during the 12-month period commencing July 2, 2026 and ending July 1, 2027.

The second quarter ended with net cash[(1)] of $566 million.

(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 October 1, 2026 to shareholders of record on September 15, 2026.

Board Changes

The Board of Directors is pleased to announce the appointment of Derek Evans and Deanna Zumwalt as independent directors of Baytex, effective July 30, 2026, following a process led by the Nominating and Governance Committee of the Board.

Derek Evans is a distinguished energy industry leader with more than four decades of experience. He served as President and Chief Executive Officer of MEG Energy, where he led a successful operational and financial turnaround over a six-year tenure, and previously as President and Chief Executive Officer of Pengrowth Energy, where he delivered the Lindbergh SAGD project on time and on budget. Following his retirement from MEG, Mr. Evans served as Executive Chairman of the Pathways Alliance and currently serves as Chair of the AltaGas board and a director of Franco-Nevada Corporation.

Deanna Zumwalt is a seasoned executive with broad experience across energy finance and operations. She spent over a decade at Nexen Energy in progressively senior roles spanning finance, natural gas and power, and North American crude oil marketing, before joining Coril Holdings Ltd., a privately held global investment company, where she served as President and Chief Executive Officer from 2021 to 2025, overseeing a diversified portfolio of assets across multiple sectors and geographies. Ms. Zumwalt has served as a director of SECURE Waste Infrastructure since 2019.

"We are pleased to welcome Derek and Deanna to the Baytex board," said Mark Bly, Chair of the Board of Directors. "Their combined experience and track record in the Canadian energy industry strengthen our board as we execute our strategy and advance opportunities in our portfolio. We look forward to their contributions in the years ahead."

Concurrent with these appointments Steve Reynish and Jeffrey Wojahn stepped down as directors. Following these changes, the Board of Directors comprises eight members, seven of whom are independent.

"We extend our sincere gratitude to Steve and Jeffrey for their guidance and contributions during their tenure and wish them well in their future endeavors," commented Mark Bly, Chair of the Board of Directors.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 30, 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 and exportation and development expenditures; the number of wells to be drilled and brought on stream in heavy oil and the Duvernay in 2026; our plans with respect to waterflood development; and that we are planning to drill two Utikuma exploration well in early 2027. 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			Six Months Ended	
($ thousands)	**June 30, 2026**	March 31, 2026	June 30, 2025	**June 30, 2026**	June 30, 2025
Petroleum and natural gas sales	**$ 639,943**	$ 452,954	$ 411,036	**$ 1,092,897**	$ 865,187
Blending and other expense	**(75,068)**	(75,921)	(62,381)	**(150,989)**	(135,201)
Total sales, net of blending and other expense	**$ 564,875**	$ 377,033	$ 348,655	**$ 941,908**	$ 729,986
Royalties	**(90,378)**	(51,589)	(47,800)	**(141,967)**	(107,056)
Operating expense	**(89,843)**	(81,244)	(88,035)	**(171,087)**	(163,615)
Transportation expense	**(25,932)**	(23,134)	(20,544)	**(49,066)**	(39,323)
Operating netback - Canada	**$ 358,722**	$ 221,066	$ 192,276	**$ 579,788**	$ 419,992

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, and payments on lease obligations.

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

	Three Months Ended			Six Months Ended	
($ thousands)	**June 30, 2026**	March 31, 2026	June 30, 2025	**June 30, 2026**	June 30, 2025
Cash flows from operating activities	**$ 230,852**	$ 122,203	$ 354,312	**$ 353,055**	$ 785,629
Change in non-cash working capital	**21,648**	26,303	9,042	**47,951**	38,076
Additions to exploration and evaluation assets	**—**	(1,737)	(930)	**(1,737)**	(930)
Additions to oil and gas properties	**(122,242)**	(143,275)	(355,602)	**(265,517)**	(760,699)
Payments on lease obligations	**(2,213)**	(1,789)	(3,634)	**(4,002)**	(6,359)
Free cash flow	**$ 128,045**	$ 1,705	$ 3,188	**$ 129,750**	$ 55,717

Working capital (surplus) deficiency

Working capital (surplus) deficiency is calculated as cash, trade receivables, prepaids and other assets, and inventory 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 June 30, 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)	**June 30, 2026**	March 31, 2026	June 30, 2025
Cash	**$ (720,337)**	$ (757,869)	$ (7,156)
Trade receivables	**(188,260)**	(194,985)	(363,507)
Prepaids and other assets	**(60,714)**	(59,091)	(75,856)
Inventory	**(8,756)**	(14,174)	—
Trade payables	**275,032**	303,107	538,330
Share-based compensation liability	**29,498**	25,748	13,851
Dividends payable	**16,144**	16,606	17,304
Other long-term liabilities	**—**	—	19,751
Working capital (surplus) deficiency	**$ (657,393)**	$ (680,658)	$ 142,717

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, prepaids and other assets, and inventory.

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

	As at		
($ thousands)	**June 30, 2026**	March 31, 2026	June 30, 2025
Credit facilities	**$ —**	$ —	$ 317,310
Unamortized debt issuance costs - Credit facilities (1)	**—**	—	16,206
Long-term notes	**89,229**	87,598	1,776,647
Unamortized debt issuance costs - Long-term notes (1)	**1,878**	1,909	41,060
Trade payables	**275,032**	303,107	538,330
Share-based compensation liability	**29,498**	25,748	13,851
Dividends payable	**16,144**	16,606	17,304
Other long-term liabilities	**—**	—	19,751
Cash	**(720,337)**	(757,869)	(7,156)
Trade receivables	**(188,260)**	(194,985)	(363,507)
Prepaids and other assets	**(60,714)**	(59,091)	(75,856)
Inventory	**(8,756)**	(14,174)	—
Net (cash) debt	**$ (566,286)**	$ (591,151)	$ 2,293,940

(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, and asset retirement 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			Six Months Ended	
($ thousands)	**June 30, 2026**	March 31, 2026	June 30, 2025	**June 30, 2026**	June 30, 2025
Cash flow from operating activities	**$ 230,852**	$ 122,203	$ 354,312	**$ 353,055**	$ 785,629
Change in non-cash working capital	**21,648**	26,303	9,042	**47,951**	38,076
Asset retirement obligations settled	**1,933**	2,619	3,565	**4,552**	7,084
Adjusted funds flow	**$ 254,433**	$ 151,125	$ 366,919	**$ 405,558**	$ 830,789

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 and six months ended June 30, 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 June 30, 2026					**Three Months Ended June 30, 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	10,328	8	27	8,350	11,755	9,308	14	34	9,845	10,997
Lloydminster	16,073	4	—	1,305	16,295	12,456	20	—	1,148	12,667
Peavine	19,370	—	—	—	19,370	19,662	—	—	—	19,662
Remaining Properties	557	2	—	643	666	1,439	2	—	770	1,569
Canada - Light										
Viking	15	8,253	249	9,479	10,096	89	7,603	198	10,761	9,684
Duvernay	—	3,606	3,259	11,939	8,854	—	3,180	2,166	7,915	6,665
Remaining Properties	6	363	874	17,786	4,207	5	348	588	11,892	2,923
Total Canada	46,349	12,236	4,409	49,502	71,243	42,959	11,167	2,986	42,331	64,167
United States										
Eagle Ford	—	—	—	—	—	—	50,941	16,962	96,151	83,928
Total	46,349	12,236	4,409	49,502	71,243	42,959	62,108	19,948	138,482	148,095

	Six Months Ended June 30, 2026					Six Months Ended June 30, 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	9,662	7	23	8,473	11,103	9,758	12	26	9,734	11,418
Lloydminster	15,776	7	—	1,223	15,988	11,905	17	—	1,169	12,117
Peavine	19,562	—	—	—	19,562	18,693	—	—	—	18,693
Remaining Properties	604	3	—	662	717	1,122	1	—	707	1,241
Canada - Light										
Viking	21	8,155	256	9,696	10,049	100	8,277	176	10,541	10,310
Duvernay	—	3,508	3,252	12,272	8,805	—	2,794	2,193	7,313	6,206
Remaining Properties	7	356	858	17,525	4,142	5	368	659	13,569	3,294
Total Canada	45,632	12,036	4,389	49,851	70,366	41,583	11,469	3,054	43,033	63,279
United States										
Eagle Ford	—	—	—	—	—	—	50,752	16,445	94,081	82,877
Total	45,632	12,036	4,389	49,851	70,366	41,583	62,221	19,499	137,114	146,156

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 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:

Chad Lundberg
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Baytex Energy Corp.

Chad Kalmakoff
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Baytex Energy Corp.
Management's Discussion and Analysis
For the three and six months ended June 30, 2026 and 2025
Dated July 30, 2026

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and six months ended June 30, 2026. This information is provided as of July 30, 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 and six months ended June 30, 2026 ("Q2/2026" and "YTD 2026") have been compared with the results for the three and six months ended June 30, 2025 ("Q2/2025" and "YTD 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 and six months ended June 30, 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 ("IASB"). 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 and six months ended June 30, 2026 and June 30, 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 June 30					
	2026			2025		
	Continuing	**Discontinued**	**Total**	Continuing	Discontinued	Total
Revenue, net of royalties						
Petroleum and natural gas sales	**$ 639,943**	**$ —**	**$ 639,943**	$ 411,036	$ 475,543	$ 886,579
Royalties	**(90,378)**	**—**	**(90,378)**	(47,800)	(129,590)	(177,390)
	549,565	**—**	**549,565**	363,236	345,953	709,189
Expenses						
Operating	**89,843**	**—**	**89,843**	88,035	72,985	161,020
Transportation	**25,932**	**—**	**25,932**	20,544	12,363	32,907
Blending and other	**75,068**	**—**	**75,068**	62,381	—	62,381
General and administrative	**16,480**	**—**	**16,480**	16,595	5,625	22,220
Exploration and evaluation	**810**	**—**	**810**	457	—	457
Depletion and depreciation	**128,945**	**—**	**128,945**	118,004	204,155	322,159
Share-based compensation	**4,317**	**—**	**4,317**	863	692	1,555
Net financing and interest expense	**4,516**	**—**	**4,516**	46,869	4,844	51,713
Financial derivatives gain	**(21,443)**	**—**	**(21,443)**	(18,663)	—	(18,663)
Foreign exchange gain	**(316)**	**—**	**(316)**	(100,586)	—	(100,586)
Gain on dispositions	**(261)**	**(6,281)**	**(6,542)**	(666)	—	(666)
Other expense (income)	**2,057**	**—**	**2,057**	2,703	(2,018)	685
	325,948	**(6,281)**	**319,667**	236,536	298,646	535,182
Net income before income taxes	**223,617**	**6,281**	**229,898**	126,700	47,307	174,007
Income taxes						
Current income tax expense (recovery)	**—**	**—**	**—**	6,038	(1,491)	4,547
Deferred income tax expense	**55,029**	**—**	**55,029**	17,644	267	17,911
	55,029	**—**	**55,029**	23,682	(1,224)	22,458
Net income	**$ 168,588**	**$ 6,281**	**$ 174,869**	$ 103,018	$ 48,531	$ 151,549

	Six Months Ended June 30					
	2026			2025		
	Continuing	**Discontinued**	**Total**	Continuing	Discontinued	Total
Revenue, net of royalties						
Petroleum and natural gas sales	**$ 1,092,897**	**$ —**	**$ 1,092,897**	$ 865,187	$ 1,020,522	$ 1,885,709
Royalties	**(141,967)**	**—**	**(141,967)**	(107,056)	(278,271)	(385,327)
	950,930	**—**	**950,930**	758,131	742,251	1,500,382
Expenses						
Operating	**171,087**	**—**	**171,087**	163,615	145,108	308,723
Transportation	**49,066**	**—**	**49,066**	39,323	24,096	63,419
Blending and other	**150,989**	**—**	**150,989**	135,201	—	135,201
General and administrative	**38,779**	**—**	**38,779**	35,161	12,665	47,826
Exploration and evaluation	**1,475**	**—**	**1,475**	564	—	564
Depletion and depreciation	**252,635**	**—**	**252,635**	234,747	407,335	642,082
Share-based compensation	**27,187**	**—**	**27,187**	1,276	1,042	2,318
Net financing and interest expense	**7,613**	**—**	**7,613**	97,436	9,523	106,959
Financial derivatives loss	**129,313**	**—**	**129,313**	30,956	—	30,956
Foreign exchange loss (gain)	**1,618**	**—**	**1,618**	(104,464)	—	(104,464)
(Gain) loss on dispositions	**(2,278)**	**(19,720)**	**(21,998)**	563	—	563
Other expense (income)	**3,761**	**—**	**3,761**	5,099	(3,225)	1,874
	831,245	**(19,720)**	**811,525**	639,477	596,544	1,236,021
Net income before income taxes	**119,685**	**19,720**	**139,405**	118,654	145,707	264,361
Income taxes						
Current income tax expense (recovery)	**—**	**1,086**	**1,086**	6,985	(286)	6,699
Deferred income tax expense	**30,776**	**—**	**30,776**	26,006	10,516	36,522
	30,776	**1,086**	**31,862**	32,991	10,230	43,221
Net income	**$ 88,909**	**$ 18,634**	**$ 107,543**	$ 85,663	$ 135,477	$ 221,140

SECOND QUARTER HIGHLIGHTS

Baytex delivered strong operating and financial results in Q2/2026, highlighted by production of 71,243 boe/d, which exceeded the high end of our annual guidance range of 69,000 - 71,000 boe/d. Strong performance in the Duvernay and across our heavy oil portfolio supported an increase to our 2026 production guidance to approximately 71,000 boe/d, with no change to our exploration and development expenditures guidance of approximately $625 million.

We invested $122.2 million in exploration and development activities during Q2/2026, consistent with our full-year capital plan and focused on our heavy oil and Duvernay development programs. During the quarter, we brought 26.0 net wells on production and continued to advance our 2026 development program.

Our financial results for Q2/2026 reflect strong operating performance and higher benchmark oil prices, partially offset by realized financial derivative losses. We generated adjusted funds flow[(1)] of $254.4 million and cash flows from operating activities of $230.9 million, compared to adjusted funds flow from continuing operations of $112.5 million and cash flows from operating activities from continuing operations of $85.7 million in Q2/2025.

We generated free cash flow[(2)] of $128.0 million in Q2/2026, reflecting the disciplined execution of our exploration and development programs while maintaining a strong balance sheet. During the quarter, we repurchased 21.7 million common shares for $138.6 million under our normal course issuer bid and declared a quarterly dividend of $0.0225 per share.

Net cash[(1)] was $566.3 million at June 30, 2026 compared to $765.8 million at December 31, 2025. The change reflects free cash flow generated during the period offset by shareholder returns, including share repurchases and 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.

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 approximately 71,000 boe/d.

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

	2026 Annual Guidance	Revised Annual Guidance	YTD 2026 Results
Exploration and development expenditures (1)	~ $625 million	No change	$267.3 million
Production (boe/d) (1)	69,000 - 71,000	~ 71,000	70,366
Expenses:			
Average royalty rate (2)(3)	15%	No change	15.1 %
Operating (2)(4)	$13.75 - $14.25/boe	No change	$13.43/boe
Transportation (2)(4)	$3.40 - $3.60/boe	No change	$3.85/boe
Leasing expenditures (2)	$7 million	No change	$4.0 million
Asset retirement obligations settled (2)	$20 million	No change	$4.6 million

(1) As announced on May 7, 2026.
(2) As announced on December 22, 2025.
(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) 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 June 30			Six Months Ended June 30		
	2026	2025	Change	**2026**	2025	Change
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**12,236**	11,167	10%	**12,036**	11,469	5%
Heavy oil	**46,349**	42,959	8%	**45,632**	41,583	10%
Natural Gas Liquids (NGL)	**4,409**	2,986	48%	**4,389**	3,054	44%
Total liquids (bbl/d)	**62,994**	57,112	10%	**62,057**	56,106	11%
Natural gas (mcf/d)	**49,502**	42,331	17%	**49,851**	43,033	16%
Daily production (boe/d) - continuing operations	**71,243**	64,167	11%	**70,366**	63,279	11%
Daily production (boe/d) - discontinued operations	**—**	83,928	(100)%	**—**	82,877	(100)%
Total production (boe/d)	**71,243**	148,095	(52)%	**70,366**	146,156	(52)%
Production Mix - continuing operations						
Light oil and condensate	**17 %**	17 %	— %	**17 %**	18 %	(1)%
Heavy oil	**65 %**	67 %	(2)%	**65 %**	66 %	(1)%
NGL	**6 %**	5 %	1 %	**6 %**	5 %	1 %
Natural gas	**12 %**	11 %	1 %	**12 %**	11 %	1 %

Production from continuing operations of 71,243 boe/d for Q2/2026 and 70,366 boe/d for YTD 2026 increased 11% for both periods compared to 64,167 boe/d for Q2/2025 and 63,279 boe/d for YTD 2025 with strong performance from both our heavy oil and Duvernay development programs over the last year.

Total production of 70,366 boe/d for YTD 2026 is consistent with our revised annual guidance of approximately 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 June 30			Six Months Ended June 30		
	2026	2025	Change	**2026**	2025	Change
WTI oil (US$/bbl) (1)	**92.79**	63.74	29.05	**82.36**	67.58	14.78
Edmonton par oil ($/bbl) (2)	**132.26**	84.15	48.11	**112.88**	89.71	23.17
Edmonton par oil differential to WTI (US$/bbl)	**2.80**	(2.94)	5.74	**(0.42)**	(3.93)	3.51
WCS heavy oil ($/bbl) (3)	**108.16**	74.10	34.06	**93.66**	79.15	14.51
WCS heavy oil differential to WTI (US$/bbl)	**(14.62)**	(10.20)	(4.42)	**(14.37)**	(11.43)	(2.94)
AECO 7A natural gas price ($/mcf) (4)	**1.51**	2.07	(0.56)	**2.00**	2.05	(0.05)
AECO 5A natural gas price ($/mcf) (5)	**1.63**	1.69	(0.06)	**1.82**	1.94	(0.12)
CAD/USD average exchange rate	**1.3836**	1.3840	(0.0004)	**1.3776**	1.4095	(0.0319)

(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$92.79/bbl for Q2/2026 and US$82.36/bbl for YTD 2026 compared to US$63.74/bbl for Q2/2025 and US$67.58/bbl for YTD 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 $132.26/bbl during Q2/2026 and $112.88/bbl for YTD 2026 compared to $84.15/bbl during Q2/2025 and $89.71/bl for YTD 2025. Edmonton par differentials strengthened in Q2/2026 as Canadian light oil benefited from tighter global light crude and refined product markets. Edmonton par traded at a premium to WTI of US$2.80/bbl for Q2/2026 and at a discount of US$0.42/bbl for YTD 2026, compared to discounts of US$2.94/bbl for Q2/2025 and US$3.93/bbl for YTD 2025.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS benchmark averaged $108.16/bbl for Q2/2026 and $93.66/bbl for YTD 2026 compared to $74.10/bbl for Q2/2025 and $79.15/bbl for YTD 2025. The WCS heavy oil differential to WTI was US$14.62/bbl in Q2/2026 and US$14.37/bbl for YTD 2026 which was wider compared to US$10.20/bbl for Q2/2025 and US$11.43/bbl for YTD 2025 reflecting higher Western Canadian supply and increased competition from other heavy and sour crude barrels delivered to the U.S. Gulf Coast.

Natural Gas

We compare our natural gas pricing to the AECO 7A benchmark which averaged $1.51/mcf during Q2/2026 and $2.00/mcf during YTD 2026 compared to $2.07/mcf for Q2/2025 and $2.05/mcf for YTD 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 June 30			Six Months Ended June 30		
	2026	2025	Change	**2026**	2025	Change
Light oil and condensate ($/bbl) (1)	**$ 131.91**	$ 82.54	$ 49.37	**$ 108.26**	$ 88.32	$ 19.94
Heavy oil, net of blending and other expense ($/bbl) (2)	**94.92**	64.43	30.49	**81.26**	68.79	12.47
NGL ($/bbl) (1)	**27.32**	22.93	4.39	**24.57**	25.54	(0.97)
Natural gas ($/mcf) (1)	**1.48**	1.73	(0.25)	**1.70**	1.89	(0.19)
Total sales, net of blending and other expense ($/boe) (2) - continuing operations	**$ 87.13**	$ 59.71	$ 27.42	**$ 73.96**	$ 63.74	$ 10.22
Total sales ($/boe) - discontinued operations	**—**	62.26	(62.26)	**—**	68.03	(68.03)
Total sales, net of blending and other expense ($/boe) (2)	**$ 87.13**	$ 61.16	$ 25.97	**$ 73.96**	$ 66.17	$ 7.79

(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 $87.13/boe for Q2/2026 and $73.96/boe for YTD 2026 compared to $59.71/boe for Q2/2025 and $63.74/boe for YTD 2025. The increase is primarily due to higher benchmark oil pricing relative to both periods of 2025.

Our realized light oil and condensate price for continuing operations represents a discount to the Edmonton par price of $0.35/bbl for Q2/2026 and $4.62/bbl for YTD 2026 compared to a discount of $1.61/bbl in Q2/2025 and $1.39/bbl in YTD 2025. The narrower discount in Q2/2026 is more reflective of normal operations and the wider discount in YTD 2026 reflects the timing of production along with the increase in benchmark oil prices during Q1 2026.

Our realized heavy oil price, net of blending and other expense for continuing operations was higher in Q2/2026 and YTD 2026 compared to the same periods of 2025 which reflects the increase in WCS benchmark pricing. Our realized pricing for Q2/2026 and YTD 2026 represents a discount to the WCS benchmark of $13.24/bbl and $12.40/bbl respectively compared to $9.67/bbl Q2/2025 and $10.36/bbl for YTD 2025 which reflects higher blending costs.

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 21% of WTI in Q2/2026 and 22% in YTD 2026 compared to 26% of WTI in Q2/2025 and 27% in YTD 2025, reflecting lower market prices for propane and butane during 2026 relative to 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 $1.48/mcf for Q2/2026 and $1.70/mcf for YTD 2026 was lower than $1.73/mcf for Q2/2025 and $1.89/mf for YTD 2025.

PETROLEUM AND NATURAL GAS SALES

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2026**	2025	Change	**2026**	2025	Change
Oil sales						
Light oil and condensate	**$ 146,868**	$ 83,876	$ 62,992	**$ 235,861**	$ 183,344	$ 52,517
Heavy oil	**475,431**	314,254	161,177	**822,168**	652,965	169,203
NGL	**10,960**	6,232	4,728	**19,520**	14,121	5,399
Total oil sales	**633,259**	404,362	228,897	**1,077,549**	850,430	227,119
Natural gas sales	**6,684**	6,674	10	**15,348**	14,757	591
Total petroleum and natural gas sales	**639,943**	411,036	228,907	**1,092,897**	865,187	227,710
Blending and other expense	**(75,068)**	(62,381)	(12,687)	**(150,989)**	(135,201)	(15,788)
Total sales, net of blending and other expense [1] - continuing operations	**$ 564,875**	$ 348,655	$ 216,220	**$ 941,908**	$ 729,986	$ 211,922
Total sales - discontinued operations	**—**	475,543	(475,543)	**—**	1,020,522	(1,020,522)
Total sales, net of blending and other expense [1]	**$ 564,875**	$ 824,198	$ (259,323)	**$ 941,908**	$ 1,750,508	$ (808,600)

(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 $564.9 million for Q2/2026 and $941.9 million for YTD 2026 compared to $348.7 million for Q2/2025 and $730.0 million for YTD 2025. The increase in total sales, net of blending and other expense reflects higher realized pricing and higher production in both Q2/2026 and YTD 2026. The increase in our realized pricing for Q2/2026 relative to Q2/2025 resulted in a $177.8 million increase in total sales, net of blending and other expense, and higher production contributed a $38.4 million increase in total sales, net of blending and other expense. Higher realized pricing resulted in a $130.1 million increase in total sales, net of blending and other expense, in YTD 2026 relative to YTD 2025 while higher production contributed an $81.8 million increase in total sales, net of blending and other expense, in YTD 2026 relative to YTD 2025.

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 and six months ended June 30, 2026 and 2025.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for % and per boe)	**2026**	2025	Change	**2026**	2025	Change
Royalties - continuing operations	**$ 90,378**	$ 47,800	$ 42,578	**$ 141,967**	$ 107,056	$ 34,911
Royalties - discontinued operations	**—**	129,590	(129,590)	**—**	278,271	(278,271)
Total royalties	**$ 90,378**	$ 177,390	$ (87,012)	**$ 141,967**	$ 385,327	$(243,360)
Average royalty rate [1] - continuing operations	**16.0 %**	13.7 %	2.3 %	**15.1 %**	14.7 %	0.4 %
Average royalty rate [1] - discontinued operations	**— %**	27.3 %	(27.3)%	**— %**	27.3 %	(27.3)%
Total average royalty rate [1]	**16.0 %**	21.5 %	(5.5)%	**15.1 %**	22.0 %	(6.9)%
Royalties per boe [2] - continuing operations	**$ 13.94**	$ 8.19	$ 5.75	**$ 11.15**	$ 9.35	$ 1.80
Royalties per boe [2] - discontinued operations	**$ —**	$ 16.97	$ (16.97)	**$ —**	$ 18.55	$ (18.55)
Total royalties per boe [2]	**$ 13.94**	$ 13.16	$ 0.78	**$ 11.15**	$ 14.57	$ (3.42)

(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 $90.4 million or 16.0% of total sales, net of blending and other expense for Q2/2026 compared to $47.8 million or 13.7% for Q2/2025. Royalties for continuing operations were $142.0 million or 15.1% of total sales, net of blending and other expense for YTD 2026 compared to $107.1 million or 14.7% for YTD 2025. Our average royalty rate was higher for Q2/2026 and YTD 2026 as a result of higher benchmark prices.

Our average royalty rate of 15.1% for YTD 2026 is consistent with our annual guidance of approximately 15% for 2026.

OPERATING EXPENSE

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2026**	2025	Change	**2026**	2025	Change
Operating expense - continuing operations	**$ 89,843**	$ 88,035	$ 1,808	**$ 171,087**	$ 163,615	$ 7,472
Operating expense - discontinued operations	**—**	72,985	(72,985)	**—**	145,108	(145,108)
Total operating expense	**$ 89,843**	$ 161,020	$ (71,177)	**$ 171,087**	$ 308,723	$ (137,636)
Operating expense per boe [(1)] - continuing operations	**$ 13.86**	$ 15.08	$ (1.22)	**$ 13.43**	$ 14.29	$ (0.86)
Operating expense per boe [(1)] - discontinued operations	**$ —**	$ 9.56	$ (9.56)	**$ —**	$ 9.67	$ (9.67)
Total operating expense per boe [(1)]	**$ 13.86**	$ 11.95	$ 1.91	**$ 13.43**	$ 11.67	$ 1.76

(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 $89.8 million ($13.86/boe) for Q2/2026 and $171.1 million ($13.43/boe) for YTD 2026 compared to $88.0 million ($15.08/boe) for Q2/2025 and $163.6 million ($14.29/boe) for YTD 2025. Operating expense for continuing operations for Q2/2026 and YTD 2026 increased compared to Q2/2025 and YTD 2025 due to increased production over the same period while per unit operating expense decreased as higher production volumes enabled costs to be absorbed over a larger production base.

Operating expense of $13.43/boe for YTD 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 and six months ended June 30, 2026 and 2025.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2026**	2025	Change	**2026**	2025	Change
Transportation expense - continuing operations	**$ 25,932**	$ 20,544	$ 5,388	**$ 49,066**	$ 39,323	$ 9,743
Transportation expense - discontinued operations	**—**	12,363	(12,363)	**—**	24,096	(24,096)
Total transportation expense	**$ 25,932**	$ 32,907	$ (6,975)	**$ 49,066**	$ 63,419	$ (14,353)
Transportation expense per boe [(1)] - continuing operations	**$ 4.00**	$ 3.52	$ 0.48	**$ 3.85**	$ 3.43	$ 0.42
Transportation expense per boe [(1)] - discontinued operations	**$ —**	$ 1.62	$ (1.62)	**$ —**	$ 1.61	$ (1.61)
Total transportation expense per boe [(1)]	**$ 4.00**	$ 2.44	$ 1.56	**$ 3.85**	$ 2.40	$ 1.45

(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 $25.9 million ($4.00/boe) for Q2/2026 and $49.1 million ($3.85/boe) for YTD 2026 compared to $20.5 million ($3.52/boe) for Q2/2025 and $39.3 million ($3.43/boe) for YTD 2025. The increase in transportation expense for both periods of 2026 reflects higher heavy oil production and an increase in trucking rates relative to 2025.

Transportation expense of $3.85/boe for YTD 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 $75.1 million for Q2/2026 and $151.0 million for YTD 2026 compared to $62.4 million for Q2/2025 and $135.2 million for YTD 2025. Higher blending and other expense for both periods in 2026 is a result of the increase in the cost of condensate purchased for blending in Q2/2026 and higher heavy oil production compared to both periods in 2025.

FINANCIAL DERIVATIVES

As part of our normal operations, our business is exposed to fluctuations in commodity prices. In an effort to manage this exposure, we may 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 and six months ended June 30, 2026 and 2025.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2026**	2025	Change	**2026**	2025	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ (84,824)**	$ (12,448)	$ (72,376)	**$ (114,715)**	$ (13,281)	$ (101,434)
Natural gas	**678**	574	104	**1,280**	1,213	67
Total	**$ (84,146)**	$ (11,874)	$ (72,272)	**$ (113,435)**	$ (12,068)	$ (101,367)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ 106,578**	$ 18,426	$ 88,152	**$ (15,492)**	$ (15,615)	$ 123
Natural gas	**(989)**	12,111	(13,100)	**(386)**	(3,273)	2,887
Total	**$ 105,589**	$ 30,537	$ 75,052	**$ (15,878)**	$ (18,888)	$ 3,010
Total financial derivatives gain (loss)						
Crude oil	**$ 21,754**	$ 5,978	$ 15,776	**$ (130,207)**	$ (28,896)	$ (101,311)
Natural gas	**(311)**	12,685	(12,996)	**894**	(2,060)	2,954
Total	**$ 21,443**	$ 18,663	$ 2,780	**$ (129,313)**	$ (30,956)	$ (98,357)

We recorded a total financial derivatives gain of $21.4 million for Q2/2026 and a loss of $129.3 million for YTD 2026 compared to a gain of $18.7 million for Q2/2025 and a loss of $31.0 million for YTD 2025. The realized financial derivatives loss of $113.4 million for YTD 2026 was primarily a result of the increase in benchmark oil prices in March 2026 resulting in market prices for crude oil settling at levels above those set in our derivative contracts which were entered into prior to the sale of our U.S. operations.The unrealized financial derivatives loss of $15.9 million for YTD 2026 reflects both the reclassification of unrealized losses to realized losses upon settlement of contracts during Q2/2026 and the increase in forecasted crude oil pricing used to revalue outstanding volumes on crude oil contracts in place at June 30, 2026, relative to December 31, 2025. The fair value of our financial derivative contracts resulted in a net asset of $10.6 million at June 30, 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 July 30, 2026.

OPERATING NETBACK

The following table summarizes our operating netback on a per boe basis for the three and six months ended June 30, 2026 and 2025.

	Three Months Ended June 30			Six Months Ended June 30		
($ per boe except for volume)	**2026**	2025	Change	**2026**	2025	Change
Daily production (boe/d) - continuing operations	**71,243**	64,167	11 %	**70,366**	63,279	11 %
Daily production (boe/d) - discontinued operations	**—**	83,928	(100)%	**—**	82,877	(100)%
Total production (boe/d)	**71,243**	148,095	(52)%	**70,366**	146,156	(52)%
Operating netback:						
Total sales, net of blending and other expense [(1)]	**$ 87.13**	$ 59.71	$ 27.42	**$ 73.96**	$ 63.74	$ 10.22
Less:						
Royalties [(2)]	**(13.94)**	(8.19)	(5.75)	**(11.15)**	(9.35)	(1.80)
Operating expense [(2)]	**(13.86)**	(15.08)	1.22	**(13.43)**	(14.29)	0.86
Transportation expense [(2)]	**(4.00)**	(3.52)	(0.48)	**(3.85)**	(3.43)	(0.42)
Operating netback [(1)] - continuing operations	**$ 55.33**	$ 32.92	$ 22.41	**$ 45.53**	$ 36.67	$ 8.86
Operating netback [(1)] - discontinued operations	**—**	34.11	(34.11)	**—**	38.20	(38.20)
Operating netback [(1)]	**$ 55.33**	$ 33.61	$ 21.72	**$ 45.53**	$ 37.53	$ 8.00
Realized financial derivatives loss [(3)]	**(12.98)**	(0.88)	(12.10)	**(8.91)**	(0.46)	(8.45)
Operating netback after financial derivatives [(1)]	**$ 42.35**	$ 32.73	$ 9.62	**$ 36.62**	$ 37.07	$ (0.45)

(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 $55.33/boe for Q2/2026 and $45.53/boe for YTD 2026 was higher than $32.92/boe for Q2/2025 and $36.67/boe for YTD 2025 due to the increase in our realized price which resulted in higher per unit sales net of royalties. Combined operating and transportation expense for Q2/2026 and YTD 2026 was consistent with the same periods of 2025. Our operating netback after financial derivatives of $42.35/boe for Q2/2026 was higher than $32.73/boe for Q2/2025 due to higher realized pricing while our operating netback after financial derivatives of $36.62/boe for YTD 2026 was lower than $37.07/boe for YTD 2025 due to higher realized financial derivatives losses in 2026 compared to 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 and six months ended June 30, 2026 and 2025.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2026**	2025 (1)	Change	**2026**	2025 (1)	Change
Gross G&A expense - continuing operations	**$ 17,876**	$ 18,179	$ (303)	**$ 42,107**	$ 38,803	$ 3,304
Overhead recoveries - continuing operations	**(1,396)**	(1,584)	188	**(3,328)**	(3,642)	314
G&A expense - continuing operations	**$ 16,480**	$ 16,595	$ (115)	**$ 38,779**	$ 35,161	$ 3,618
G&A expense - discontinued operations (2)	**—**	5,625	(5,625)	**—**	12,665	(12,665)
Total G&A expense	**$ 16,480**	$ 22,220	$ (5,740)	**$ 38,779**	$ 47,826	$ (9,047)
G&A expense per boe (3) - continuing operations	**$ 2.54**	$ 2.84	$ (0.30)	**$ 3.04**	$ 3.07	$ (0.03)
G&A expense per boe (3) - discontinued operations	**$ —**	$ 0.74	$ (0.74)	**$ —**	$ 0.84	$ (0.84)
Total G&A expense per boe (3)	**$ 2.54**	$ 1.65	$ 0.89	**$ 3.04**	$ 1.81	$ 1.23

(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 $16.5 million ($2.54/boe) for Q2/2026 and $38.8 million ($3.04/boe) for YTD 2026 compared to $16.6 million ($2.84/boe) for Q2/2025 and $35.2 million ($3.07/boe) for YTD 2025. G&A expense for continuing operations includes severance and other non-recurring costs related to staff reductions in Canada which resulted in higher G&A expense for YTD 2026 compared to YTD 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 and six months ended June 30, 2026 and 2025.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2026**	2025 (1)	Change	**2026**	2025 (1)	Change
Interest on credit facilities	**$ 842**	$ 3,502	$ (2,660)	**$ 1,729**	$ 6,839	$ (5,110)
Interest on long-term notes	**1,636**	37,683	(36,047)	**3,355**	77,962	(74,607)
Interest on lease obligations	**1,443**	337	1,106	**2,538**	662	1,876
Interest income	**(4,623)**	(42)	(4,581)	**(11,078)**	(392)	(10,686)
Net cash interest (income) expense	**$ (702)**	$ 41,480	$ (42,182)	**$ (3,456)**	$ 85,071	$ (88,527)
Amortization of debt issue costs	**63**	3,526	(3,463)	**579**	5,904	(5,325)
Accretion of asset retirement obligations	**5,155**	4,618	537	**10,193**	9,216	977
Early redemption expense (gain)	**—**	(2,755)	2,755	**297**	(2,755)	3,052
Net financing and interest expense - continuing operations	**$ 4,516**	$ 46,869	$ (42,353)	**$ 7,613**	$ 97,436	$ (89,823)
Net financing and interest expense - discontinued operations	**—**	4,844	(4,844)	**—**	9,523	(9,523)
Total net financing and interest expense	**$ 4,516**	$ 51,713	$ (47,197)	**$ 7,613**	$ 106,959	$ (99,346)
Net financing and interest expense per boe (2) - continuing operations	**$ 0.70**	$ 8.03	$ (7.33)	**$ 0.60**	$ 8.51	$ (7.91)
Net financing and interest expense per boe (2) - discontinued operations	**$ —**	$ 0.63	$ (0.63)	**$ —**	$ 0.63	$ (0.63)
Total net financing and interest expense per boe (2)	**$ 0.70**	$ 3.84	$ (3.14)	**$ 0.60**	$ 4.04	$ (3.44)

(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 $4.5 million ($0.70/boe) for Q2/2026 and $7.6 million ($0.60/boe) for YTD 2026 compared to $46.9 million ($8.03/boe) for Q2/2025 and $97.4 million ($8.51/boe) for YTD 2025. Lower net financing and interest expense for Q2/2026 and YTD 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 $0.7 million for Q2/2026 and $3.5 million for YTD 2026 compared to interest expense of $41.5 million for Q2/2025 and $85.1 million for YTD 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 Q2/2026 and YTD 2026. Interest on our credit facilities for Q2/2026 and YTD 2026 reflects the standby fees rate of 0.5% compared to the weighted average interest rate of 6.5% for Q2/2025 and 6.6% for YTD 2025. Interest income for Q2/2026 and YTD 2026 reflects interest earned on cash deposits held in high-interest savings accounts during the period.

Accretion of asset retirement obligations for continuing operations of $5.2 million for Q2/2026 and $10.2 million for YTD 2026 was consistent with $4.6 million for Q2/2025 and $9.2 million for YTD 2025. Amortization of debt issue costs for continuing operations of $0.1 million for Q2/2026 and $0.6 million for YTD 2026 was lower than $3.5 million for Q2/2025 and $5.9 million for YTD 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 $0.8 million for Q2/2026 and $1.5 million for YTD 2026 compared to $0.5 million for Q2/2025 and $0.6 million for YTD 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 and six months ended June 30, 2026 and 2025.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2026**	2025 (1)	Change	**2026**	2025 (1)	Change
Depletion and depreciation - continuing operations	**$ 128,945**	$ 118,004	$ 10,941	**$ 252,635**	$ 234,747	$ 17,888
Depletion and depreciation - discontinued operations	**—**	204,155	(204,155)	**—**	407,335	(407,335)
Total depletion and depreciation	**$ 128,945**	$ 322,159	$ (193,214)	**$ 252,635**	$ 642,082	$ (389,447)
Depletion and depreciation per boe (2) - continuing operations	**$ 19.89**	$ 20.21	$ (0.32)	**$ 19.84**	$ 20.50	$ (0.66)
Depletion and depreciation per boe (2) - discontinued operations	**$ —**	$ 26.73	$ (26.73)	**$ —**	$ 27.15	$ (27.15)
Total depletion and depreciation per boe (2)	**$ 19.89**	$ 23.90	$ (4.01)	**$ 19.84**	$ 24.27	$ (4.43)

(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 $128.9 million ($19.89/boe) for Q2/2026 and $252.6 million ($19.84/boe) for YTD 2026 compared to $118.0 million ($20.21/boe) for Q2/2025 and $234.7 million ($20.50/boe) for YTD 2025. Depletion and depreciation expense for continuing operations was higher in Q2/2026 and YTD 2026 relative to Q2/2025 and YTD 2025 due to higher production as the depletion rate has decreased.

IMPAIRMENT

We concluded there were no indicators of impairment or impairment reversal on all of our oil and gas properties and exploration and evaluation assets at June 30, 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 equity-classified awards is recognized in net income or loss over the vesting period of the awards with a corresponding increase in contributed surplus. 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 $4.3 million for Q2/2026 and $27.2 million for YTD 2026 for our continuing operations compared to $0.9 million for Q2/2025 and $1.3 million for YTD 2025. The increase for Q2/2026 and YTD 2026 primarily reflects changes in the Company's share price, which increased the value of the awards resulting in higher SBC expense relative to the same periods in 2025. The total expense for YTD 2026 for continuing operations is comprised of $22.3 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.

($ thousands except for exchange rates)	Three Months Ended June 30						Six Months Ended June 30					
		2026		2025		Change		**2026**		2025		Change
Unrealized foreign exchange loss (gain)	**$**	**1,693**	$	(100,792)	$	102,485	**$**	**3,323**	$	(104,267)	$	107,590
Realized foreign exchange (gain) loss		**(2,009)**		206		(2,215)		**(1,705)**		(197)		(1,508)
Foreign exchange (gain) loss - continuing operations	**$**	**(316)**	$	(100,586)	$	100,270	**$**	**1,618**	$	(104,464)	$	106,082
CAD/USD exchange rates:												
At beginning of period		**1.3956**		1.4379				**1.3715**		1.4405		
At end of period		**1.4206**		1.3622				**1.4206**		1.3622		

We recorded a foreign exchange gain for continuing operations of $0.3 million for Q2/2026 and loss of $1.6 million for YTD 2026 compared to gains of $100.6 million for Q2/2025 and $104.5 million for YTD 2025.

The unrealized foreign exchange loss for continuing operations of $1.7 million for Q2/2026 and $3.3 million for YTD 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 June 30, 2026 compared to March 31, 2026 and December 31, 2025. The unrealized foreign exchange gain of $100.8 million for Q2/2025 and $104.3 million for YTD 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 June 30, 2025 compared to March 31, 2025 and 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 gain for continuing operations of $2.0 million for Q2/2026 and $1.7 million for YTD 2026 compared to a loss of $0.2 million for Q2/2025 and a gain of $0.2 million for YTD 2025.

INCOME TAXES

($ thousands)	Three Months Ended June 30						Six Months Ended June 30					
		2026		2025 (1)		Change		**2026**		2025 (1)		Change
Current income tax expense	**$**	**—**	$	6,038	$	(6,038)	**$**	**—**	$	6,985	$	(6,985)
Deferred income tax expense		**55,029**		17,644		37,385		**30,776**		26,006		4,770
Income tax expense - continuing operations	**$**	**55,029**	$	23,682	$	31,347	**$**	**30,776**	$	32,991	$	(2,215)
Income tax (recovery) expense - discontinued operations	**$**	**—**	$	(1,224)	$	1,224	**$**	**—**	$	10,230	$	(10,230)

(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 Q2/2026 and YTD 2026 and recorded an expense of $6.0 million for Q2/2025 and $7.0 million for YTD 2025.

We recorded a deferred income tax expense for continuing operations of $55.0 million for Q2/2026 and $30.8 million for YTD 2026 compared to expense of $17.6 million for Q2/2025 and $26.0 million for YTD 2025. The deferred tax expense for Q2/2026 and YTD 2026 reflects an effective tax rate of 24.6% and 25.7% which is similar to our statutory rate of 24.2%.

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 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 AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income or loss for the three and six months ended June 30, 2026 and 2025 are set forth in the following table.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2026**	2025 (1)	Change	**2026**	2025 (1)	Change
Petroleum and natural gas sales	**$ 639,943**	$ 411,036	$ 228,907	**$ 1,092,897**	$ 865,187	$ 227,710
Royalties	**(90,378)**	(47,800)	(42,578)	**(141,967)**	(107,056)	(34,911)
Revenue, net of royalties	**549,565**	363,236	186,329	**950,930**	758,131	192,799
Expenses						
Operating	**(89,843)**	(88,035)	(1,808)	**(171,087)**	(163,615)	(7,472)
Transportation	**(25,932)**	(20,544)	(5,388)	**(49,066)**	(39,323)	(9,743)
Blending and other	**(75,068)**	(62,381)	(12,687)	**(150,989)**	(135,201)	(15,788)
Operating netback (2) from continuing operations	**$ 358,722**	$ 192,276	$ 166,446	**$ 579,788**	$ 419,992	$ 159,796
General and administrative	**(16,480)**	(16,595)	115	**(38,779)**	(35,161)	(3,618)
Net cash interest income (expense)	**702**	(41,480)	42,182	**3,456**	(85,071)	88,527
Realized financial derivatives loss	**(84,146)**	(11,874)	(72,272)	**(113,435)**	(12,068)	(101,367)
Realized foreign exchange gain (loss)	**2,009**	(206)	2,215	**1,705**	197	1,508
Cash other expense	**(2,057)**	(2,703)	646	**(3,761)**	(5,099)	1,338
Current income tax expense	**—**	(6,038)	6,038	**—**	(6,985)	6,985
Cash share-based compensation	**(4,317)**	(863)	(3,454)	**(22,330)**	(1,276)	(21,054)
Adjusted funds flow (3) from continuing operations	**$ 254,433**	$ 112,517	$ 141,916	**$ 406,644**	$ 274,529	$ 132,115
Exploration and evaluation	**(810)**	(457)	(353)	**(1,475)**	(564)	(911)
Depletion and depreciation	**(128,945)**	(118,004)	(10,941)	**(252,635)**	(234,747)	(17,888)
Non-cash share-based compensation	**—**	—	—	**(4,857)**	—	(4,857)
Non-cash financing and interest	**(5,218)**	(5,389)	171	**(11,069)**	(12,365)	1,296
Unrealized financial derivatives gain (loss)	**105,589**	30,537	75,052	**(15,878)**	(18,888)	3,010
Unrealized foreign exchange (loss) gain	**(1,693)**	100,792	(102,485)	**(3,323)**	104,267	(107,590)
Gain (loss) on dispositions	**261**	666	(405)	**2,278**	(563)	2,841
Deferred income tax expense	**(55,029)**	(17,644)	(37,385)	**(30,776)**	(26,006)	(4,770)
Net income from continuing operations	**$ 168,588**	$ 103,018	$ 65,570	**$ 88,909**	$ 85,663	$ 3,246
Net income from discontinued operations	**6,281**	48,531	(42,250)	**18,634**	135,477	(116,843)
Net income	**$ 174,869**	$ 151,549	$ 23,320	**$ 107,543**	$ 221,140	$ (113,597)

(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 from continuing operations of $254.4 million for Q2/2026 and $406.6 million for YTD 2026 compared to $112.5 million for Q2/2025 and $274.5 million for YTD 2025. The increase in adjusted funds flow for both periods of 2026 is a result of an increase in operating netback which is primarily due to higher benchmark pricing, an increase in production and lower cash interest expense due to the repayment of nearly all outstanding debt in Q4/2025. The increase in operating netback was partially offset by higher realized losses on financial derivatives.

We reported net income from continuing operations of $168.6 million for Q2/2026 and $88.9 million for YTD 2026 compared to $103.0 million for Q2/2025 and $85.7 million for YTD 2025. The increase in net income for both periods of 2026 relative to 2025 is due to an increase in adjusted funds flow as well as higher unrealized financial derivative gains, partially offset by lower unrealized foreign exchange gains.

CAPITAL EXPENDITURES

Capital expenditures for the three and six months ended June 30, 2026 and 2025 are summarized as follows.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2026**	2025	Change	**2026**	2025	Change
Drilling, completion and equipping	**$ 98,546**	$ 121,950	$ (23,404)	**$ 220,126**	$ 289,428	$ (69,302)
Facilities and other	**23,696**	25,784	(2,088)	**47,128**	42,625	4,503
Exploration and development expenditures - continuing operations	**$ 122,242**	$ 147,734	$ (25,492)	**$ 267,254**	$ 332,053	$ (64,799)
Exploration and development expenditures - discontinued operations	**—**	208,798	(208,798)	**—**	429,576	(429,576)
Total exploration and development expenditures	**$ 122,242**	$ 356,532	$ (234,290)	**$ 267,254**	$ 761,629	$ (494,375)
Property acquisitions - continuing operations	**$ 226**	$ 905	$ (679)	**$ 8,353**	$ 1,374	$ 6,979
Proceeds from dispositions - continuing operations	**$ 162**	$ (863)	$ 1,025	**$ 202**	$ (3,540)	$ 3,742
Property acquisitions - discontinued operations	**$ —**	$ 288	$ (288)	**$ —**	$ 1,076	$ (1,076)
Proceeds from dispositions - discontinued operations	**$ (6,281)**	$ 138	$ (6,419)	**$ (19,434)**	$ 549	$ (19,983)

Exploration and development expenditures for continuing operations were $122.2 million in Q2/2026 and $267.3 million for YTD 2026 compared to $147.7 million in Q2/2025 and $332.1 million in YTD 2025. Exploration and development expenditures for continuing operations for YTD 2026 included costs associated with drilling 96 (78.5 net) wells along with 90 (78.8 net) wells that were brought on production compared to drilling 124 (118.6 net) wells along with 132 (126.6 net) wells brought on production during YTD 2025. We also invested $47.1 million on facilities and other expenditures during YTD 2026.

Exploration and development expenditures of $267.3 million for YTD 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. Baytex assesses its capital structure in response to operational requirements and changes in economic conditions. At June 30, 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 liquidity levels. There is no certainty that any of these additional sources of capital would be available if required.

At June 30, 2026 we had net cash(1) of $566.3 million compared to $765.8 million at December 31, 2025. The decrease in net cash from December 31, 2025 primarily reflects shareholder returns of $342.9 million during YTD 2026, which includes share buybacks and quarterly dividends, partially offset by $129.8 million of free cash flow(2) earned during YTD 2026.

(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.

Credit Facilities

At June 30, 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 June 30, 2026.

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 June 30, 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 June 30, 2026.

Covenant Description	Position as at June 30, 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)	**9.3:1.0**	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 June 30, 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 June 30, 2026 was $758.9 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 June 30, 2026 was $81.5 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 June 30, 2026, the Company's Total Debt totaled $95.5 million of principal amounts outstanding.

Long-Term Notes

During YTD 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 June 30, 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 six months ended June 30, 2026, we issued 0.1 million common shares pursuant to our share-based compensation program. As at June 30, 2026, we had 708.9 million common shares issued and outstanding and no preferred shares issued and outstanding. As at July 30, 2026, there were 699.2 million common shares issued and outstanding and no preferred shares issued and outstanding.

During the six months ended June 30, 2026, we repurchased 56.8 million common shares under our normal course issuer bid ("NCIB") at an average price of $5.46 per share for total consideration of $310.1 million. In June 2026, the Toronto Stock Exchange ("TSX") accepted the renewal of our NCIB under which we are permitted to purchase for cancellation up to 70.9 million common shares over the 12-month period commencing July 2, 2026, which represents 10% of the Company's public float, as defined by the TSX, as at June 19, 2026. We have obtained an exemption order from the Canadian securities regulators which permits us to purchase common shares through the New York Stock Exchange and other U.S. based trading systems.

During the six months ended June 30, 2026, we recorded a $6.2 million charge to shareholders' capital related to the federal tax on equity repurchases (December 31, 2025 - $0.5 million).

On January 2, April 1, 2026 and July 2, 2026, we paid quarterly cash dividends of $0.0225 per share to shareholders of record. On July 30, 2026, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on October 1, 2026 to shareholders of record on September 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 June 30, 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
Long-term notes - principal	**$ 91,107**	$ —	$ —	$ —	$ 91,107
Interest on long-term notes	**38,381**	6,719	13,438	13,438	4,786
Lease obligations - principal	**96,756**	15,837	23,396	18,049	39,474
Processing agreements	**4,496**	630	543	525	2,798
Transportation agreements	**66,410**	36,092	24,381	3,320	2,617
Total	**$ 297,150**	$ 59,278	$ 61,758	$ 35,332	$ 140,782

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 June 30, 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)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Petroleum and natural gas sales	**639,943**	452,954	759,815	927,648	886,579	999,130	1,017,017	1,074,623
Net income (loss) - continuing operations (1)	**168,588**	(79,679)	(334,057)	(28,451)	103,018	(17,355)	(124,903)	96,204
Per common share - basic	**0.23**	(0.11)	(0.43)	(0.04)	0.13	(0.02)	(0.16)	0.12
Per common share - diluted	**0.23**	(0.11)	(0.43)	(0.04)	0.13	(0.02)	(0.16)	0.12
Net income (loss)	**174,869**	(67,326)	(856,887)	31,968	151,549	69,591	(38,477)	185,219
Per common share - basic	**0.24**	(0.09)	(1.12)	0.04	0.20	0.09	(0.05)	0.23
Per common share - diluted	**0.24**	(0.09)	(1.12)	0.04	0.20	0.09	(0.05)	0.23
Adjusted funds flow (2)	**254,433**	151,125	261,531	422,232	366,919	463,870	461,886	537,947
Per common share - basic	**0.35**	0.20	0.34	0.55	0.48	0.60	0.59	0.68
Per common share - diluted	**0.35**	0.20	0.34	0.55	0.48	0.60	0.59	0.67
Free cash flow (3)	**128,045**	1,705	76,486	142,688	3,188	52,529	254,838	220,159
Per common share - basic	**0.18**	—	0.10	0.19	—	0.07	0.33	0.28
Per common share - diluted	**0.18**	—	0.10	0.18	—	0.07	0.33	0.28
Cash flows from operating activities	**230,852**	122,203	227,657	472,676	354,312	431,317	468,865	550,042
Per common share - basic	**0.32**	0.16	0.30	0.62	0.46	0.56	0.60	0.69
Per common share - diluted	**0.32**	0.16	0.30	0.61	0.46	0.56	0.60	0.69
Dividends declared	**16,144**	16,606	17,268	17,326	17,304	17,289	17,598	17,732
Per common share	**0.0225**	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225
Exploration and development	**122,242**	145,012	174,078	270,364	356,532	405,097	198,177	306,332
Canada	**122,242**	145,012	92,720	123,579	147,734	184,319	108,971	120,473
U.S. (4)	**—**	—	81,358	146,785	208,798	220,778	89,206	185,859
Property acquisitions	**226**	8,127	5,544	24,024	1,193	1,257	12,621	1,042
Proceeds from dispositions	**(6,119)**	(13,113)	(3,012,058)	(8,254)	(725)	(2,266)	(42,339)	(1,436)
Net (cash) debt (2)	**(566,286)**	(591,151)	(765,785)	2,244,358	2,293,940	2,390,250	2,417,172	2,493,269
Total assets	**3,169,943**	3,252,692	3,345,414	7,601,389	7,552,013	7,824,576	7,759,745	7,614,157
Common shares outstanding	**708,888**	730,561	765,568	768,317	768,317	770,039	773,590	787,328
Daily production								
Total production (boe/d)	**71,243**	69,478	137,087	150,950	148,095	144,194	152,894	154,468
Canada (boe/d)	**71,243**	69,478	67,295	68,185	64,167	62,380	65,332	64,668
U.S. (boe/d) (4)	**—**	—	69,792	82,765	83,928	81,814	87,562	89,800
Benchmark prices								
WTI oil (US$/bbl)	**92.79**	71.93	59.14	64.93	63.74	71.42	70.27	75.10
WCS heavy oil ($/bbl)	**108.16**	49.28	66.88	75.14	74.10	84.33	80.77	83.98
Edmonton par oil ($/bbl)	**132.26**	93.50	76.49	86.20	84.15	95.27	94.98	97.91
AECO 7A natural gas ($/mcf)	**1.51**	2.49	2.34	1.00	2.07	2.02	1.46	0.81
CAD/USD avg exchange rate	**1.3836**	1.3716	1.3949	1.3774	1.3840	1.4350	1.3992	1.3636
Total sales, net of blending and other expense ($/boe) (3)	**87.13**	60.30	56.28	63.22	61.16	71.38	66.60	71.97
Royalties ($/boe) (5)	**(13.94)**	(8.25)	(11.54)	(13.05)	(13.16)	(16.02)	(14.69)	(15.75)
Operating expense ($/boe) (5)	**(13.86)**	(12.99)	(12.51)	(11.54)	(11.95)	(11.38)	(10.36)	(11.76)
Transportation expense ($/boe) (5)	**(4.00)**	(3.70)	(2.43)	(2.54)	(2.44)	(2.35)	(2.35)	(2.60)
Operating netback ($/boe) (3)	**55.33**	35.36	29.80	36.09	33.61	41.63	39.20	41.86
Financial derivatives (loss) gain ($/boe) (5)	**(12.98)**	(4.68)	0.08	(0.62)	(0.88)	(0.01)	(0.15)	0.02
Operating netback after financial derivatives ($/boe) (3)	**42.35**	30.68	29.88	35.47	32.73	41.62	39.05	41.88

(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 71,243 boe/d in Q2/2026 and 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 YTD 2026 resulted in production growth to 71,243 boe/d from 64,668 boe/d in Q3/2024 despite the disposition of certain thermal assets in Q4/2024.

Benchmark prices for crude oil declined from Q3/2024 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 and remained volatile through Q2/2026 due to supply disruptions related to the conflict in Iran and resulted in realized pricing of $87.13/boe for Q2/2026 and operating netback after financial derivatives of $42.35/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 $254.4 million and cash flows from operating activities of $230.9 million for Q2/2026 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 $566.3 million at Q2/2026 compared to a net debt position of $2.5 billion at Q3/2024. The change in net (cash) debt also reflects free cash flow(2) of $659.5 million generated in the period since Q3/2024, along with $511.2 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 June 30, 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 six months ended June 30, 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 June 30		Six Months Ended June 30	
($ thousands)	**2026**	2025	**2026**	2025
Petroleum and natural gas sales	**$ 639,943**	$ 411,036	**$ 1,092,897**	$ 865,187
Light oil and condensate (1)	**(146,868)**	(83,876)	**(235,861)**	(183,344)
NGL (1)	**(10,960)**	(6,232)	**(19,520)**	(14,121)
Natural gas (1)	**(6,684)**	(6,674)	**(15,348)**	(14,757)
Heavy oil	**$ 475,431**	$ 314,254	**$ 822,168**	$ 652,965
Blending and other expense (2)	**(75,068)**	(62,381)	**(150,989)**	(135,201)
Heavy oil, net of blending and other expense	**$ 400,363**	$ 251,873	**$ 671,179**	$ 517,764

(1) Component of petroleum and natural gas sales. See Note 14 - Petroleum and Natural Gas Sales in the consolidated financial statements for the three and six months ended June 30, 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 reduce price uncertainty 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 June 30		Six Months Ended June 30	
($ thousands)	**2026**	2025	**2026**	2025
Petroleum and natural gas sales	**$ 639,943**	$ 411,036	**$ 1,092,897**	$ 865,187
Blending and other expense	**(75,068)**	(62,381)	**(150,989)**	(135,201)
Total sales, net of blending and other expense	**564,875**	348,655	**941,908**	729,986
Royalties	**(90,378)**	(47,800)	**(141,967)**	(107,056)
Operating expense	**(89,843)**	(88,035)	**(171,087)**	(163,615)
Transportation expense	**(25,932)**	(20,544)	**(49,066)**	(39,323)
Operating netback - continuing operations	**$ 358,722**	$ 192,276	**$ 579,788**	$ 419,992
Realized financial derivatives loss [(1)]	**(84,146)**	(11,874)	**(113,435)**	(12,068)
Operating netback after realized financial derivatives - continuing operations	**$ 274,576**	$ 180,402	**$ 466,353**	$ 407,924

(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 and six months ended June 30, 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 June 30		Six Months Ended June 30	
($ thousands)	**2026**	2025	**2026**	2025
Cash flows from operating activities	**$ 230,852**	$ 354,312	**$ 353,055**	$ 785,629
Change in non-cash working capital	**21,648**	9,042	**47,951**	38,076
Additions to exploration and evaluation assets	**—**	(930)	**(1,737)**	(930)
Additions to oil and gas properties	**(122,242)**	(355,602)	**(265,517)**	(760,699)
Payments on lease obligations	**(2,213)**	(3,634)	**(4,002)**	(6,359)
Free cash flow	**$ 128,045**	$ 3,188	**$ 129,750**	$ 55,717

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 reduce price uncertainty 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)	**June 30, 2026**	December 31, 2025
Credit facilities	**$ —**	$ 1,138
Unamortized debt issuance costs - Credit facilities [1]	**—**	262
Long-term notes	**89,229**	93,834
Unamortized debt issuance costs - Long-term notes [1]	**1,878**	2,113
Trade payables	**275,032**	236,373
Share-based compensation liability	**29,498**	34,802
Dividends payable	**16,144**	17,268
Cash	**(720,337)**	(953,113)
Trade receivables	**(188,260)**	(135,230)
Prepaids and other assets	**(60,714)**	(63,232)
Inventory	**(8,756)**	—
Net cash	**$ (566,286)**	$ (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 and six months ended June 30, 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 June 30		Six Months Ended June 30	
($ thousands)	**2026**	2025	**2026**	2025
Cash flow from operating activities	**$ 230,852**	$ 354,312	**$ 353,055**	$ 785,629
Change in non-cash working capital	**21,648**	9,042	**47,951**	38,076
Asset retirement obligations settled	**1,933**	3,565	**4,552**	7,084
Adjusted funds flow	**$ 254,433**	$ 366,919	**$ 405,558**	$ 830,789

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 and six months ended June 30, 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 may seek 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 June 30, 2026	As at December 31, 2025
ASSETS			
Current assets			
Cash	18	**$ 720,337**	$ 953,113
Trade receivables	14, 18	**188,260**	135,230
Prepaids and other assets		**36,050**	35,008
Inventory		**8,756**	—
Financial derivatives	18	**10,614**	28,898
Assets held for sale	3	**—**	38,117
		964,017	1,190,366
Non-current assets			
Exploration and evaluation assets	4	**140,301**	133,585
Oil and gas properties	5	**1,961,679**	1,918,435
Other plant and equipment		**7,265**	7,648
Lease assets	7	**56,430**	20,812
Prepaids and other assets	15	**24,664**	28,224
Deferred income tax asset	15	**15,587**	46,344
		$ 3,169,943	$ 3,345,414
LIABILITIES			
Current liabilities			
Trade payables	18	**$ 275,032**	$ 236,373
Share-based compensation liability	12	**23,406**	26,108
Dividends payable	11, 18	**16,144**	17,268
Financial derivatives	18	**—**	2,406
Liabilities related to assets held for sale	3	**—**	23,710
Lease obligations	7	**10,449**	7,175
Asset retirement obligations	10	**17,346**	17,138
		342,377	330,178
Non-current liabilities			
Share-based compensation liability	12	**6,092**	8,694
Credit facilities	8, 18	**—**	1,138
Long-term notes	9, 18	**89,229**	93,834
Lease obligations	7	**49,807**	15,844
Asset retirement obligations	10	**529,154**	506,677
		1,016,659	956,365
SHAREHOLDERS' EQUITY			
Shareholders' capital	11	**5,611,565**	6,072,562
Contributed surplus		**547,905**	397,681
Accumulated other comprehensive income		**13,571**	13,356
Deficit		**(4,019,757)**	(4,094,550)
		2,153,284	2,389,049
		$ 3,169,943	$ 3,345,414

Subsequent event (note 11)

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended June 30		Six Months Ended June 30	
	Notes	**2026**	2025 Revised (1)	**2026**	2025 Revised (1)
Revenue, net of royalties					
Petroleum and natural gas sales	14	**$ 639,943**	$ 411,036	**$ 1,092,897**	$ 865,187
Royalties		**(90,378)**	(47,800)	**(141,967)**	(107,056)
		549,565	363,236	**950,930**	758,131
Expenses					
Operating		**89,843**	88,035	**171,087**	163,615
Transportation		**25,932**	20,544	**49,066**	39,323
Blending and other		**75,068**	62,381	**150,989**	135,201
General and administrative		**16,480**	16,595	**38,779**	35,161
Exploration and evaluation	4	**810**	457	**1,475**	564
Depletion and depreciation		**128,945**	118,004	**252,635**	234,747
Share-based compensation	12	**4,317**	863	**27,187**	1,276
Net financing and interest expense	16	**4,516**	46,869	**7,613**	97,436
Financial derivatives (gain) loss	18	**(21,443)**	(18,663)	**129,313**	30,956
Foreign exchange (gain) loss	17	**(316)**	(100,586)	**1,618**	(104,464)
(Gain) loss on dispositions		**(261)**	(666)	**(2,278)**	563
Other expense		**2,057**	2,703	**3,761**	5,099
		325,948	236,536	**831,245**	639,477
Net income before income taxes from continuing operations		**223,617**	126,700	**119,685**	118,654
Income taxes	15				
Current income tax expense		**—**	6,038	**—**	6,985
Deferred income tax expense		**55,029**	17,644	**30,776**	26,006
		55,029	23,682	**30,776**	32,991
Net income from continuing operations		**$ 168,588**	$ 103,018	**$ 88,909**	$ 85,663
Net income from discontinued operations	6	**$ 6,281**	$ 48,531	**$ 18,634**	$ 135,477
Net income		**$ 174,869**	$ 151,549	**$ 107,543**	$ 221,140
Other comprehensive income (loss)					
Foreign currency translation adjustment		**405**	(247,444)	**215**	(255,866)
Comprehensive income (loss)		**$ 175,274**	$ (95,895)	**$ 107,758**	$ (34,726)
Net income per common share					
Continuing operations - basic		**$ 0.23**	$ 0.14	**$ 0.12**	$ 0.11
Discontinued operations - basic		**$ 0.01**	$ 0.06	**$ 0.03**	$ 0.18
Net income per share - basic		**$ 0.24**	$ 0.20	**$ 0.15**	$ 0.29
Continuing operations - diluted		**$ 0.23**	$ 0.14	**$ 0.12**	$ 0.11
Discontinued operations - diluted		**$ 0.01**	$ 0.06	**$ 0.03**	$ 0.18
Net income per share - diluted		**$ 0.24**	$ 0.20	**$ 0.15**	$ 0.29
Weighted average common shares (000's)	13				
Basic		**721,197**	768,717	**734,105**	770,072
Diluted		**725,970**	772,032	**738,529**	773,448

(1) Comparative period has been revised to reflect current period presentation of continuing and discontinued operations. See Note 6 for additional information.

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		(43,123)	25,964	—	—	**(17,159)**
Dividends declared		—	—	—	(34,593)	**(34,593)**
Comprehensive (loss) income		—	—	(255,866)	221,140	**(34,726)**
Balance at June 30, 2025		$ 6,094,686	$ 387,818	$ 837,395	$ (3,235,037)	**$ 4,084,862**
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	(461,685)	145,367	—	—	**(316,318)**
Dividends declared	11	—	—	—	(32,750)	**(32,750)**
Comprehensive income		—	—	215	107,543	**107,758**
Balance at June 30, 2026		$ 5,611,565	$ 547,905	$ 13,571	$ (4,019,757)	**$ 2,153,284**

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 June 30		Six Months Ended June 30	
	Notes	**2026**	2025	**2026**	2025
CASH PROVIDED BY (USED IN):					
Operating activities					
Net income		**$ 174,869**	$ 151,549	**$ 107,543**	$ 221,140
Adjustments for:					
Non-cash share-based compensation	12	**—**	—	**4,857**	—
Unrealized foreign exchange loss (gain)	17	**1,693**	(100,792)	**3,323**	(104,267)
Exploration and evaluation	4	**810**	457	**1,475**	564
Depletion and depreciation		**128,945**	322,159	**252,635**	642,082
Non-cash financing and interest	16	**5,218**	6,838	**11,069**	15,297
Unrealized financial derivatives (gain) loss	18	**(105,589)**	(30,537)	**15,878**	18,888
(Gain) loss on dispositions		**(6,542)**	(666)	**(21,998)**	563
Deferred income tax expense	15	**55,029**	17,911	**30,776**	36,522
Asset retirement obligations settled	10	**(1,933)**	(3,565)	**(4,552)**	(7,084)
Change in non-cash working capital		**(21,648)**	(9,042)	**(47,951)**	(38,076)
Cash flows from operating activities		**230,852**	354,312	**353,055**	785,629
Financing activities					
(Decrease) increase in credit facilities	8	**—**	91,852	**(1,400)**	2,147
Deferred finance costs		**—**	(2,714)	**—**	(2,714)
Payments on lease obligations	7	**(2,213)**	(3,634)	**(4,002)**	(6,359)
Redemption of long-term notes	9	**—**	(53,681)	**(8,270)**	(53,681)
Repurchase of common shares	11	**(138,603)**	(4,137)	**(316,318)**	(17,159)
Dividends declared	11	**(16,144)**	(17,304)	**(32,750)**	(34,593)
Change in non-cash working capital		**3,440**	(3,657)	**5,257**	(2,803)
Cash flows (used in) from financing activities		**(153,520)**	6,725	**(357,483)**	(115,162)
Investing activities					
Additions to exploration and evaluation assets	4	**—**	(930)	**(1,737)**	(930)
Additions to oil and gas properties	5	**(122,242)**	(355,602)	**(265,517)**	(760,699)
Additions to other plant and equipment		**(346)**	(235)	**(666)**	(794)
Consideration related to assets held for sale	3	**—**	—	**14,407**	—
Property acquisitions		**(226)**	(1,193)	**(8,353)**	(2,450)
Proceeds from dispositions		**6,119**	725	**19,232**	2,991
Change in non-cash working capital		**1,831**	(2,612)	**12,483**	81,961
Cash flows used in investing activities		**(114,864)**	(359,847)	**(230,151)**	(679,921)
Change in cash		**(37,532)**	1,190	**(234,579)**	(9,454)
Opening balance prior to restatement for IFRS 9 amendments		**757,869**	5,966	**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		**757,869**	5,966	**954,916**	16,610
Cash, end of period		**$ 720,337**	$ 7,156	**$ 720,337**	$ 7,156
Supplementary information					
Interest paid		**$ 842**	$ 53,957	**$ 5,295**	$ 90,632
Interest received		**$ 4,884**	$ —	**$ 10,329**	$ —
Income taxes paid		**$ 29,770**	$ 14,321	**$ 29,770**	$ 19,641
Income taxes refunded		**$ 7,592**	$ —	**$ 7,592**	$ —

See accompanying notes to the condensed consolidated interim financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the “Company” or “Baytex”) is engaged in the business of acquiring, developing and operating oil and natural gas properties and related assets in the Western Canadian Sedimentary Basin. The Company’s common shares are traded on the Toronto Stock Exchange ("TSX") and the New York Stock Exchange ("NYSE") 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 July 30, 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

	June 30, 2026	December 31, 2025
Balance, beginning of period	**$ 133,585**	$ 124,355
Additions to exploration and evaluation assets	**1,737**	930
Property acquisitions	**8,208**	34,148
Divestitures	**(567)**	(8,577)
Exploration and evaluation expense	**(1,475)**	(5,534)
Transfer to oil and gas properties (note 5)	**(1,187)**	(11,737)
Balance, end of period	**$ 140,301**	$ 133,585

At June 30, 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		265,517		—		265,517
Property acquisitions		145		—		145
Transfers from exploration and evaluation assets (note 4)		1,187		—		1,187
Change in asset retirement obligations (note 10)		20,146		—		20,146
Divestitures		(55)		—		(55)
Depletion		—		(243,696)		(243,696)
Balance, June 30, 2026	**$**	**7,649,522**	**$**	**(5,687,843)**	**$**	**1,961,679**

At June 30, 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 and six months ended June 30, 2026, the Company recorded post-closing adjustments of $6.3 million and $18.6 million respectively.

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

	Three Months Ended June 30		Six Months Ended June 30	
	2026	2025	**2026**	2025
Revenue, net of royalties				
Petroleum and natural gas sales	**$ —**	$ 475,543	**$ —**	$ 1,020,522
Royalties	**—**	(129,590)	**—**	(278,271)
	—	345,953	**—**	742,251
Expenses				
Operating	**—**	72,985	**—**	145,108
Transportation	**—**	12,363	**—**	24,096
General and administrative	**—**	5,625	**—**	12,665
Depletion and depreciation	**—**	204,155	**—**	407,335
Share-based compensation	**—**	692	**—**	1,042
Financing and interest	**—**	4,844	**—**	9,523
Other income	**—**	(2,018)	**—**	(3,225)
	—	298,646	**—**	596,544
Net income before income taxes - operations	**—**	47,307	**—**	145,707
Income taxes - operations				
Current income tax recovery - operations	**—**	(1,491)	**—**	(286)
Deferred income tax expense - operations	**—**	267	**—**	10,516
	—	(1,224)	**—**	10,230
Net income - operations	**$ —**	$ 48,531	**$ —**	$ 135,477
Gain on disposition after tax	**6,281**	—	**18,634**	—
Net income - discontinued operations	**$ 6,281**	$ 48,531	**$ 18,634**	$ 135,477

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

	Three Months Ended June 30		Six Months Ended June 30	
	2026	2025	**2026**	2025
Cash provided by (used in) discontinued operations:				
Operating activities	**$ —**	$ 268,626	**$ —**	$ 544,852
Financing activities	**—**	95,021	**—**	39,390
Investing activities	**(750)**	(209,132)	**12,403**	(377,709)
(Decrease) increase in cash from discontinued operations	**$ (750)**	$ 154,515	**$ 12,403**	$ 206,533

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	—	39,745	478	40,223
Modifications	27	1,040	(50)	1,017
Depreciation	(664)	(4,577)	(381)	(5,622)
Balance, June 30, 2026	**$ 5,208**	**$ 50,225**	**$ 997**	**$ 56,430**

Lease Obligations

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

	June 30, 2026	December 31, 2025
Less than 1 year	**$ 15,837**	$ 8,487
1 - 3 years	**23,396**	10,690
3 - 5 years	**18,049**	7,097
After 5 years	**39,474**	—
Total lease payments	**96,756**	26,274
Amounts representing interest over the term of the lease	**(36,500)**	(3,255)
Present value of net lease payments	**60,256**	23,019
Less current portion of lease obligations	**10,449**	7,175
Non-current portion of lease obligations	**$ 49,807**	$ 15,844

For the three and six months ended June 30, 2026 the Company recorded interest expense related to its lease obligations of $1.4 million and $2.5 million respectively ($0.3 million and $0.7 million for the three and six months ended June 30, 2025). For the three and six months ended June 30, 2026 the Company recorded lease payments, excluding interest, of $2.2 million and $4.0 million respectively ($3.6 million and $6.4 million for the three and six months ended June 30, 2025).

8. CREDIT FACILITIES

	June 30, 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 June 30, 2026 is the result of repayments of $1.4 million.

At June 30, 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 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 June 30, 2026.

Covenant Description	**Position as at June 30, 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)	**9.3:1.0**	**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 June 30, 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 June 30, 2026 was $758.9 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 June 30, 2026 was $81.5 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 June 30, 2026, the Company's Total Debt totaled $95.5 million of principal amounts outstanding.

At June 30, 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

	June 30, 2026	December 31, 2025
7.375% notes due March 15, 2032 [1]	**$ 91,107**	$ 95,947
Unamortized debt issuance costs	**(1,878)**	(2,113)
Total long-term notes - net of unamortized debt issuance costs	**$ 89,229**	$ 93,834

(1) The U.S. dollar denominated principal outstanding of the 7.375% notes was US$64.1 million as at June 30, 2026 (December 31, 2025 - US$70.0 million). The decrease in the principal amount outstanding from December 31, 2025 to June 30, 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 $3.1 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 six months ended June 30, 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

	June 30, 2026	December 31, 2025
Balance, beginning of period	**$ 523,815**	$ 640,951
Liabilities incurred [(1)]	**8,019**	20,794
Liabilities settled	**(4,552)**	(20,318)
Liabilities divested	**(3,102)**	(104,223)
Accretion (note 16)	**10,193**	23,012
Change in estimate [(1)]	**1,155**	(7,442)
Changes in discount and inflation rates [(1)(2)]	**10,972**	(24,663)
Foreign currency translation	**—**	(4,296)
Balance, end of period	**$ 546,500**	$ 523,815
Less current portion of asset retirement obligations	**17,346**	17,138
Non-current portion of asset retirement obligations	**$ 529,154**	$ 506,677

(1) The total of these items reflects the total change in asset retirement obligations of $20.1 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 June 30, 2026 were 3.8% 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 June 30, 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	(56,805)	(461,685)
Balance, June 30, 2026	**708,888**	**$ 5,611,565**

Normal Course Issuer Bid ("NCIB") Share Repurchases

On June 26, 2026, Baytex announced that the TSX accepted the renewal of the NCIB under which Baytex is permitted to purchase for cancellation up to 70.9 million common shares over the 12-month period commencing July 2, 2026, which represents 10% of the Company's public float, as defined by the TSX, as at June 19, 2026. 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 19, 2026, Baytex had 712.6 million common shares outstanding.

During the six months ended June 30, 2026, Baytex recorded $316.3 million related to common share repurchases, which includes $310.1 million of consideration paid for the repurchase and cancellation of common shares as well as $6.2 million (December 31, 2025 - $0.5 million) of federal tax levied on common share repurchases taxed at 2%.

Purchases are made on the open market at prices prevailing at the time of the transaction. During the six months ended June 30, 2026, Baytex repurchased and cancelled 56.8 million common shares (8.1 million for the year ended December 31, 2025) at an average price of $5.46 per share ($3.55 for the year ended December 31, 2025) for total consideration of $310.1 million ($28.9 million for the year ended December 31, 2025). 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.

Dividends

The following dividends were declared by Baytex during the six months ended June 30, 2026.

Record Date	Payable Date	Per Share Amount		Dividend Amount
March 13, 2026	April 1, 2026	$	0.0225	$ 16,606
June 15, 2026	July 2, 2026		0.0225	16,144
Total dividends declared				**$ 32,750**

On July 30, 2026, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on October 1, 2026 to shareholders of record on September 15, 2026.

12. SHARE-BASED COMPENSATION PLAN

For the three and six months ended June 30, 2026 the Company recorded share-based compensation expense for continuing operations of $4.3 million and $27.2 million respectively which includes $4.9 million of non-cash compensation expense recorded in the six months ended June 30, 2026 related to certain awards designated as equity-settled as well as cash compensation expense related to cash-settled awards for both periods. For the three and six months ended June 30, 2025, the Company recorded share-based compensation expense of $0.9 million and $1.3 million respectively for continuing operations and $0.7 million and $1.0 million for discontinued operations respectively which was related to cash-settled awards.

The Company's closing share price on the TSX on June 30, 2026 was $5.69 (December 31, 2025 - $4.44 and June 30, 2025 - $2.44).

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 six months ended June 30, 2026 was $5.57 per restricted and performance award ($2.93 for the six months ended June 30, 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 six months ended June 30, 2026 was $5.52 per incentive award ($2.93 for the six months ended June 30, 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 six months ended June 30, 2026 was $6.13 per DSU award ($2.67 for the six months ended June 30, 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	—	1,328	1,742	88	3,158
Added by performance factor	—	269	—	—	269
Vested	(23)	(2,414)	(2,356)	(236)	(5,029)
Forfeited	—	(43)	(296)	—	(339)
Total, June 30, 2026	**—**	**3,980**	**4,542**	**1,798**	**10,320**

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 June 30		Six Months Ended June 30	
(000s)	**2026**	2025	**2026**	2025
Weighted average common shares - basic	**721,197**	768,717	**734,105**	770,072
Dilutive effect of share-based compensation	**4,773**	3,315	**4,424**	3,376
Weighted average common shares - diluted	**725,970**	772,032	**738,529**	773,448

For the three and six months ended June 30, 2026 and June 30, 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 June 30		Six Months Ended June 30	
	2026	2025 (1)	**2026**	2025 (1)
Light oil and condensate	**$ 146,868**	$ 83,876	**$ 235,861**	$ 183,344
Heavy oil	**475,431**	314,254	**822,168**	652,965
NGL	**10,960**	6,232	**19,520**	14,121
Natural gas	**6,684**	6,674	**15,348**	14,757
Total petroleum and natural gas sales - continuing operations	**$ 639,943**	$ 411,036	**$ 1,092,897**	$ 865,187
Total petroleum and natural gas sales - discontinued operations	**$ —**	$ 475,543	**$ —**	$ 1,020,522

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

Included in trade receivables at June 30, 2026 is $166.8 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 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 June 30		Six Months Ended June 30	
	2026	2025 (1)	**2026**	2025 (1)
Interest on Credit Facilities	**$ 842**	$ 3,502	**$ 1,729**	$ 6,839
Interest on long-term notes	**1,636**	37,683	**3,355**	77,962
Interest on lease obligations	**1,443**	337	**2,538**	662
Interest income	**(4,623)**	(42)	**(11,078)**	(392)
Net cash interest (income) expense	**$ (702)**	$ 41,480	**$ (3,456)**	$ 85,071
Amortization of debt issue costs	**63**	3,526	**579**	5,904
Accretion on asset retirement obligations (note 10)	**5,155**	4,618	**10,193**	9,216
Early redemption expense (gain)	**—**	(2,755)	**297**	(2,755)
Net financing and interest expense - continuing operations	**$ 4,516**	$ 46,869	**$ 7,613**	$ 97,436
Net financing and interest expense - discontinued operations	**$ —**	$ 4,844	**$ —**	$ 9,523

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

17. FOREIGN EXCHANGE

	Three Months Ended June 30		Six Months Ended June 30	
	2026	2025	**2026**	2025
Unrealized foreign exchange loss (gain)	**$ 1,693**	$ (100,792)	**$ 3,323**	$ (104,267)
Realized foreign exchange (gain) loss	**(2,009)**	206	**(1,705)**	(197)
Foreign exchange (gain) loss - continuing operations	**$ (316)**	$ (100,586)	**$ 1,618**	$ (104,464)

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:

	June 30, 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	**$ 10,614**	**$ 10,614**	$ 28,898	$ 28,898	Level 2
Total	**$ 10,614**	**$ 10,614**	$ 28,898	$ 28,898	
Amortized cost					
Cash	**$ 720,337**	**$ 720,337**	$ 953,113	$ 953,113	—
Trade receivables	**188,260**	**188,260**	135,230	135,230	—
Total	**$ 908,597**	**$ 908,597**	$ 1,088,343	$ 1,088,343	
Financial Liabilities					
Fair value through profit and loss					
Financial derivatives	**$ —**	**$ —**	$ (2,406)	$ (2,406)	Level 2
Total	**$ —**	**$ —**	$ (2,406)	$ (2,406)	
Amortized cost					
Trade payables	**$ (275,032)**	**$ (275,032)**	$ (236,373)	$ (236,373)	—
Dividends payable	**(16,144)**	**(16,144)**	(17,268)	(17,268)	—
Credit Facilities (1)	**—**	**—**	(1,138)	(1,400)	—
Long-term notes	**(89,229)**	**(94,248)**	(93,834)	(99,808)	Level 1
Total	**$ (380,405)**	**$ (385,424)**	$ (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 six months ended June 30, 2026 and 2025.

Foreign Currency Risk

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

	Assets		Liabilities	
	June 30, 2026	December 31, 2025	**June 30, 2026**	December 31, 2025
U.S. dollar denominated	**US$12,114**	US$22,204	**US$80,085**	US$84,500

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following commodity financial derivative contracts outstanding as at July 30, 2026.

	Remaining Period	Volume	Price/Unit (1)	Index
Oil				
Basis differential	Jul 2026 to Sep 2026	2,500 bbl/d	WTI less US$13.05/bbl	WCS
Basis differential	Jul 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	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	Jul 2026 to Sep 2026	3,000 bbl/d	WTI less US$2.70/bbl	MSW
Natural Gas				
Swap	Jul 2026 to Dec 2026	2,000 GJ/d	$3.21/GJ	AECO
Swap	Jul 2026 to Dec 2026	7,000 GJ/d	$1.64/GJ	AECO
Basis differential	Jul 2026 to Dec 2026	2,500 mmbtu/d	NYMEX less US$1.66/mmbtu	NYMEX/AECO
Collar	Jul 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.

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

	Three Months Ended June 30		Six Months Ended June 30	
	2026	2025	**2026**	2025
Realized financial derivatives loss	**$ 84,146**	$ 11,874	**$ 113,435**	$ 12,068
Unrealized financial derivatives (gain) loss	**(105,589)**	(30,537)	**15,878**	18,888
Financial derivatives (gain) loss	**$ (21,443)**	$ (18,663)	**$ 129,313**	$ 30,956

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. Baytex assesses its capital structure in response to operational requirements and changes in economic conditions. At June 30, 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.

		June 30, 2026		December 31, 2025
Credit Facilities	**$**	**—**	$	1,138
Unamortized debt issuance costs - Credit Facilities (note 8)		**—**		262
Long-term notes		**89,229**		93,834
Unamortized debt issuance costs - Long-term notes (note 9)		**1,878**		2,113
Trade payables		**275,032**		236,373
Share-based compensation liability		**29,498**		34,802
Dividends payable		**16,144**		17,268
Cash		**(720,337)**		(953,113)
Trade receivables		**(188,260)**		(135,230)
Prepaids and other assets		**(60,714)**		(63,232)
Inventory		**(8,756)**		—
Net Cash	**$**	**(566,286)**	$	(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 June 30				Six Months Ended June 30			
		2026		2025		**2026**		2025
Cash flows from operating activities	**$**	**230,852**	$	354,312	**$**	**353,055**	$	785,629
Change in non-cash working capital		**21,648**		9,042		**47,951**		38,076
Asset retirement obligations settled		**1,933**		3,565		**4,552**		7,084
Adjusted Funds Flow	**$**	**254,433**	$	366,919	**$**	**405,558**	$	830,789

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
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
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
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**

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David L. Pearce [2,4]
Director

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Director

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(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

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Chad L. Kalmakoff
Chief Financial Officer

Kendall D. Arthur
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Nicole M. Frechette
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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

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