BAYTEX REPORTS THIRD QUARTER 2026 RESULTS; ANNOUNCES INCREASED 2026 CAPITAL PLAN, 2027 GUIDANCE AND ACCELERATED THREE-YEAR GROWTH OUTLOOK

CALGARY, ALBERTA (November 5, 2026) - Baytex Energy Corp. ("Baytex" or the "Company") (TSX:BTE) (NYSE:BTE) reports its operating and financial results for the three and nine months ended September 30, 2026 (all amounts are in Canadian dollars unless otherwise noted).

"Third-quarter results were highlighted by strong safety performance, record Duvernay production and continued execution across our heavy oil portfolio," said Chad Lundberg, President and Chief Executive Officer. “With the strength of our business we are accelerating development across an opportunity-rich portfolio through the remainder of 2026 and into 2027. The updated three-year outlook is significantly enhanced through disciplined capital allocation, resulting in production growth increasing to 8% to 10% while an improved cost structure and capital efficiencies achieve the WTI US$50/bbl breakeven target in 2027."

Third Quarter Highlights

- Delivered production of 71,606 boe/d (89% oil and NGL), up 5% from Q3/2025 and in line with the full-year plan.
- Record Duvernay production of 12,806 boe/d (80% oil and NGL), up 26% compared to Q3/2025, and achieved drill and completion costs of $930/ft of completed lateral through efficiencies and cost savings - down 11% from 2025.
- Completed tuck-in acquisitions adding 15,000 acres to core Duvernay, increasing total land position by 16% in 2026.
- Generated adjusted funds flow(1) of $332 million ($0.48 per basic share) and cash flows from operating activities of $283 million ($0.41 per basic share).
- Delivered free cash flow(2) of $139 million ($0.20 per basic share) after exploration and development expenditures of $186 million and net income from continuing operations of $160 million ($0.23 per basic share).
- Repurchased 24 million common shares (3.4% of shares outstanding) for $149 million and paid the quarterly cash dividend of $16 million ($0.0225 per share), while exiting the quarter with net cash(1) of $522 million.

(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 Specified Financial Measures section in this press release for further information.

2027 Budget and Three-Year Plan Highlights

The updated outlook reflects improved capital efficiency, lower operating costs and a lower decline rate.

- 2026 exploration and development expenditures are now expected to be $665 million (up from $625 previously) with accelerated Duvernay, heavy oil and enhanced oil recovery development.
- 2027 production is expected to average 76,000 to 79,000 boe/d (7% to 11% annual growth) and ~83,000 boe/d in Q4/2027, reflecting 15% growth from Q4/2026, with exploration and development expenditures of $775 - $850 million.
- Improved three-year outlook (2027 to 2029) reflects 8% - 10% annual production growth to ~92,000 boe/d in 2029, with annual exploration and development expenditures of approximately $800 million.
- With improved costs and cycle times, Duvernay growth to 25,000 boe/d is achieved in the second half of 2028, one and a half years earlier than the previous, leaving over 15 years of hold flat inventory once 25,000 boe/d is achieved.
- Enhanced oil recovery investment to reduce decline rate and sustaining capital requirements. Waterflood pilots at Peavine and Morinville are ongoing and Lloydminster polymer flood projects are being developed in 2026 and 2027.
- The Gemini thermal modular SAGD project is being advanced towards a target financial investment decision in H2'2027, to further enhance the three-year plan.
- Industry-leading financial position supports continued shareholder returns through production growth, share repurchases and a base dividend, targeting a 15% annual total shareholder return at a mid-cycle price of WTI US$70/bbl.

	Three Months Ended			Nine Months Ended	
	September 30, 2026	June 30, 2026	September 30, 2025	**September 30, 2026**	September 30, 2025
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales - Canada	**$ 605,859**	$ 639,943	$ 437,905	**$ 1,698,756**	$ 1,303,092
Adjusted funds flow (1)	**331,884**	254,433	422,232	**737,442**	1,253,021
Per share – basic	**0.48**	0.35	0.55	**1.02**	1.63
Per share – diluted	**0.47**	0.35	0.55	**1.02**	1.62
Free cash flow (2)	**138,506**	128,045	142,688	**268,256**	198,405
Per share – basic	**0.20**	0.18	0.19	**0.37**	0.26
Per share – diluted	**0.20**	0.18	0.18	**0.37**	0.26
Cash flows from operating activities	**283,034**	230,852	472,676	**636,089**	1,258,305
Per share – basic	**0.41**	0.32	0.62	**0.88**	1.64
Per share – diluted	**0.40**	0.32	0.61	**0.88**	1.63
Net income	**160,268**	174,869	31,968	**267,811**	253,108
Per share – basic	**0.23**	0.24	0.04	**0.37**	0.33
Per share – diluted	**0.23**	0.24	0.04	**0.37**	0.33
Dividends declared	**15,578**	16,144	17,326	**48,328**	51,919
Per share	**0.0225**	0.0225	0.0225	**0.0675**	0.0675
Capital Expenditures					
Exploration and development expenditures	**$ 186,429**	$ 122,242	$ 270,364	**$ 453,683**	$ 1,031,993
Acquisitions and (divestitures)	**11,827**	(5,893)	15,770	**948**	15,229
Total oil and natural gas capital expenditures	**$ 198,256**	$ 116,349	$ 286,134	**$ 454,631**	$ 1,047,222
Net (Cash) Debt					
Credit facilities	**$ —**	$ —	$ 182,345	**$ —**	$ 182,345
Long-term notes	**91,011**	91,107	1,855,605	**91,011**	1,855,605
Total debt (3)	**91,011**	91,107	2,037,950	**91,011**	2,037,950
Working capital (surplus) deficiency (2)	**(613,378)**	(657,393)	206,408	**(613,378)**	206,408
Net (cash) debt (1)	**$ (522,367)**	$ (566,286)	$ 2,244,358	**$ (522,367)**	$ 2,244,358
Shares Outstanding - basic (thousands)					
Weighted average	**695,878**	721,197	768,317	**721,223**	769,481
End of period	**684,800**	708,888	768,317	**684,800**	768,317
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 85.79**	$ 92.79	$ 64.93	**$ 83.50**	$ 66.70
Edmonton par ($/bbl)	**119.21**	132.26	86.20	**114.99**	88.54
Edmonton par differential to WTI (US$/bbl)	**(0.57)**	2.80	(2.35)	**(0.46)**	(3.40)
WCS heavy oil ($/bbl)	**100.59**	108.16	75.14	**95.95**	77.80
WCS differential to WTI (US$/bbl)	**(13.88)**	(14.62)	(10.38)	**(14.21)**	(11.08)
Natural gas					
NYMEX (US$/MMbtu)	**$ 2.95**	$ 2.90	$ 3.07	**$ 3.63**	$ 3.39
AECO ($/Mcf)	**1.54**	1.51	1.00	**1.85**	1.70
CAD/USD average exchange rate	**1.3988**	1.3836	1.3774	**1.3847**	1.3988

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 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			Nine Months Ended	
	September 30, 2026	June 30, 2026	September 30, 2025	**September 30, 2026**	September 30, 2025
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**14,891**	12,236	12,605	**12,998**	11,852
Heavy oil (bbl/d)	**44,341**	46,349	45,269	**45,197**	42,825
NGL (bbl/d)	**4,719**	4,409	3,485	**4,500**	3,199
Total liquids (bbl/d)	**63,951**	62,994	61,359	**62,695**	57,876
Natural gas (Mcf/d)	**45,926**	49,502	40,961	**48,529**	42,335
Total Canada (boe/d) [1]	**71,606**	71,243	68,185	**70,784**	64,932
Discontinued operations (boe/d) [1]	**—**	—	82,765	**—**	82,839
Oil equivalent (boe/d) [1]	**71,606**	71,243	150,950	**70,784**	147,771
Adjusted Funds Flow (thousands of Canadian dollars)					
Total sales, net of blending and other expense [2]	**$ 551,479**	$ 564,875	$ 388,155	**$ 1,493,387**	$ 1,118,141
Royalties	**(94,469)**	(90,378)	(53,645)	**(236,436)**	(160,701)
Operating expense	**(84,377)**	(89,843)	(84,994)	**(255,464)**	(248,609)
Transportation expense	**(23,078)**	(25,932)	(23,060)	**(72,144)**	(62,383)
Operating netback - Canada [2]	**$ 349,555**	$ 358,722	$ 226,456	**$ 929,343**	$ 646,448
General and administrative expense	**(12,445)**	(16,480)	(15,824)	**(51,224)**	(50,985)
Cash share-based compensation	**(9,166)**	(4,317)	(8,440)	**(31,496)**	(9,716)
Net cash interest income (expense)	**540**	702	(39,906)	**3,996**	(124,977)
Realized financial derivatives gain (loss)	**5,808**	(84,146)	(8,580)	**(107,627)**	(20,648)
Other [3]	**(2,408)**	(48)	(1,859)	**(4,464)**	(13,746)
Adjusted funds flow - Canada [4]	**$ 331,884**	$ 254,433	$ 151,847	**$ 738,528**	$ 426,376
Adjusted funds flow - Discontinued operations [4]	**—**	—	270,385	**(1,086)**	826,645
Adjusted funds flow [4]	**$ 331,884**	$ 254,433	$ 422,232	**$ 737,442**	$ 1,253,021
Adjusted Funds Flow (per boe)					
Total sales, net of blending and other expense [2]	**$ 83.71**	$ 87.13	$ 61.88	**$ 77.28**	$ 63.08
Royalties [5]	**(14.34)**	(13.94)	(8.55)	**(12.24)**	(9.07)
Operating expense [5]	**(12.81)**	(13.86)	(13.55)	**(13.22)**	(14.02)
Transportation expense [5]	**(3.50)**	(4.00)	(3.68)	**(3.73)**	(3.52)
Operating netback - Canada [2]	**$ 53.06**	$ 55.33	$ 36.10	**$ 48.09**	$ 36.47
General and administrative expense [5]	**(1.89)**	(2.54)	(2.52)	**(2.65)**	(2.88)
Cash share-based compensation [5]	**(1.39)**	(0.66)	(1.35)	**(1.63)**	(0.55)
Net cash interest income (expense) [5]	**0.08**	0.11	(6.36)	**0.21**	(7.05)
Realized financial derivatives gain (loss) [5]	**0.88**	(12.98)	(1.37)	**(5.57)**	(1.16)
Other [3][5]	**(0.37)**	(0.01)	(0.30)	**(0.23)**	(0.78)
Adjusted funds flow - Canada [4]	**$ 50.37**	$ 39.25	$ 24.20	**$ 38.22**	$ 24.05
Adjusted funds flow - Discontinued operations [4]	**—**	—	35.51	**—**	36.55
Adjusted funds flow [4]	**$ 50.37**	$ 39.25	$ 30.40	**$ 38.16**	$ 31.06

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 and current income tax expense or recovery. Refer to the Q3/2026 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, cash share-based compensation, 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.

Third Quarter 2026 Results

Q3 Production and Capital Consistent with Full-Year Plan

Third-quarter production of 71,606 boe/d (89% oil and NGL) and exploration and development expenditures of $186 million were in line with our full-year plan.

Strong realized pricing and efficient execution of the capital program generated adjusted funds flow(1) of $332 million ($0.48 per basic share) and free cash flow(2) of $139 million ($0.20 per basic share). Net income was $160 million ($0.23 per basic share).

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Duvernay

The second Duvernay pad of 2026 (five wells) was brought onstream in late August. This pad generated average 30-day initial production rates of 1,489 boe/d per well, 87% liquids (973 bbl/d of oil, 317 bbl/d of NGLs and 1,190 mcf/d of natural gas). The third Duvernay pad of 2026 (four wells) is currently being brought onstream. Both pads are on our northern Pembina acreage.

Improved drilling and completions performance has shortened cycle times and reduced costs, contributing to a lower corporate breakeven and enhanced free cash flow generation. Drill and completion costs for 2026 full-length wells of $930/ft of completed lateral surpassed budget expectations and improved by 11% relative to 2025. The resulting cycle time improvement allows for two additional drills in Q4/2026, increasing total wells drilled in 2026 to 19 with 13 wells onstream. The remaining 6 wells will be brought onstream in 2027.

Tuck-in acquisitions completed during the year have increased our Duvernay land holdings to 106,000 net acres, an increase of 16%.

Heavy Oil

Five drill rigs ran in Q3/2026 with 25.5 net wells onstream; 9.0 net Clearwater wells at Peavine, 5.6 net wells at Peace River and 10.9 net wells at Lloydminster.

At Peavine, strong new well performance continued with wells brought onstream during the quarter establishing an average 30-day initial production rate of 408 bbl/d per well. One rig has been active on the Peavine lands in 2026. As a result of efficient operations, five wells have been added to the fourth quarter drilling program for a total of 31 wells planned in the Clearwater for 2026.

At Lloydminster, two rigs focused on the Mannville stack in northeast Alberta were running during the third quarter. Six upper and lower Waseca multi-lateral horizontal wells were brought onstream and established an average 30-day initial production rate of 186 bbl/d per well. One step-out circulation string horizontal trial was brought onstream from the GP formation and established a 30-day initial production rate of 165 bbl/d.

One rig has been active at Peace River since mid-July. Five Bluesky wells brought onstream during the third quarter established average 30-day initial production rates of 225 bbl/d per well. A total of 13.6 net wells are planned on Peace River lands in 2026, including four additional drills added to the fourth quarter program with efficiency gains to-date.

There is one rig drilling at Morinville with plans to bring 4.3 net Clearwater equivalent multi-lateral horizontal wells onstream during Q4/2026.

A total of 108.9 net heavy oil wells will be brought onstream in 2026.

Polymer Flood Development at Lloydminster and Waterflood Pilots on Injection

The expanded fourth-quarter program includes $13 million for additional polymer flood development at Lloydminster. This project is expected to be on production in Q2/2027.

At Peavine, water injection is underway across two pilot areas with five patterns currently on injection at expected rates and a sixth expected to be on injection in Q4/2026, a response is expected by mid-2027. In addition, a waterflood pilot is underway at Morinville, targeting the Rex formation (a Clearwater equivalent), with drilling completed and injection scheduled to begin in Q4/2026.

Current primary development at Peavine and Morinville maintains optionality for future waterflood development. Successful polymer floods and waterflood will moderate corporate production decline and lower sustaining capital requirements.

Portfolio Optimization Transactions

Several acquisition and divestiture transactions were completed for net consideration of $12 million. Total Duvernay land holdings have increased by 16% to 106,000 net acres through acquisitions contiguous to the core Pembina position. A tuck-in acquisition was completed in northeast Alberta, adding approximately 200 bbl/d of heavy oil production and five sections of multi-zone potential Mannville lands. High operating cost heavy oil assets producing approximately 275 bbl/d were sold for proceeds of $7 million.

Delivering Shareholder Returns

A total of $165 million was returned to shareholders during the third quarter, as 24 million common shares repurchased for $149 million, at an average price of $6.18 per share, and a quarterly cash dividend of $16 million ($0.0225 per share) was paid. Since the disposition of the U.S. business in December 2025 and through October 30, 2026, 91.7 million common shares have been repurchased for $527.9 million, representing 12% of shares outstanding, at an average price of $5.75 per share.

A Normal Course Issuer Bid ("NCIB") is in place with the Toronto Stock Exchange and allows the purchase of up to 70.9 million common shares (10% of Baytex's public float) during the 12-month period commencing July 2, 2026 and ending July 1, 2027.

Quarterly Dividend

The Board of Directors declared a quarterly cash dividend of $0.0225 per share, payable January 4, 2027 to shareholders of record on December 15, 2026.

Outlook: Accelerated Growth, Investing in Organic Opportunities, Delivering Shareholder Returns

Accelerated 2026 Development

2026 exploration and development expenditures of $665 million reflect accelerated Duvernay and heavy oil development along with expanded polymer flood development at Lloydminster. The incremental exploration and development expenditures are not expected to contribute to production in 2026. Annual production guidance remains 71,000 boe/d which equates to Q4/2026 production of 72,000 boe/d.

Higher benchmark prices have resulted in updated annual guidance for the average royalty rate to approximately 16% (previously 15%). Updated operating costs of approximately $13.30/boe (previously $13.75 - $14.25) reflects operating cost savings achieved in 2026 and increased production. Transportation costs are expected to be approximately $3.75/boe for 2026 (previously $3.40 - $3.60/boe).

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

	2026 Annual Guidance	Revised Annual Guidance
Exploration and development expenditures [(1)]	~ $625 million	~ $665 million
Production (boe/d) [(2)]	~ 71,000	No change
Expenses:		
Average royalty rate [(3)(4)]	15%	16 %
Operating [(3)(5)]	$13.75 - $14.25/boe	$13.30/boe
Transportation [(3)(5)]	$3.40 - $3.60/boe	$3.75/boe
Leasing expenditures [(3)]	$7 million	No change
Asset retirement obligations settled [(3)]	$20 million	No change

(1) As announced on May 7, 2026.
(2) As announced July 30, 2026.
(3) As announced on December 22, 2025.
(4) 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.
(5) Calculated as royalties, operating expense, or transportation expense divided by barrels of oil equivalent production volume for the applicable period.

2027 Capital Program Driving 7% - 11% Production Growth

For 2027, exploration and development expenditures guidance of $775 million to $850 million is expected to generate annual production of 76,000 to 79,000 boe/d (7% to 11% growth) while also advancing medium and long-term opportunities within the portfolio. The plan achieves the sustaining capital breakeven target of WTI US$50/bbl in 2027, reflecting an improved cost structure and capital efficiency. The 2027 capital program also includes investments in long-term infrastructure and enhanced oil recovery projects, delineation of heavy oil inventory and advances the Gemini thermal project. Approximately 60% of the program is allocated to the second half of the year.

Initially, $150 million has been allocated to share repurchases under the NCIB in 2027 with the flexibility to adjust depending on market conditions. The annual dividend is expected to be maintained at $0.09 per share ($0.0225 per share paid quarterly), subject to Board of Directors approval.

Three-Year Growth Outlook with Improving Profitability

The updated three-year outlook (2027 to 2029) targets 8% - 10% annual production growth with improving profitability through a lower cost structure, reduced corporate declines, lower sustaining capital requirements and a lower corporate breakeven price. These improvements support stronger free cash flow generation. High-impact organic opportunities which are additive to this outlook, including Clearwater waterflood and thermal, are also being advanced. Average annual exploration and development expenditures of approximately $800 million are expected to result in production of 92,000 boe/d in 2029.

A projected net cash financial position through the outlook period at a mid-cycle price of WTI US$70/bbl, supports the 15% annual total shareholder return target through production growth, share repurchases and the base dividend.

Duvernay

The transition to full-scale commercial development in the Duvernay will be completed with plans to bring 21 wells onstream in 2027 compared to 13 wells onstream in 2026. This pace of activity represents an optimized single-rig drilling program designed to deliver production growth of 64%, average annual production of approximately 18,000 boe/d and a targeted fourth quarter average production rate of 22,000 to 23,000 boe/d. Approximately 40% of the 2027 capital program is allocated to the Duvernay. Infrastructure investments include infield gathering systems, anchor oil batteries, fluid handling, and water infrastructure.

Operating the Duvernay to maximize efficiency is a priority in the three-year plan. The single-rig drilling program is expected to generate 35% annual production growth and produce 25,000 boe/d production in the second half of 2028, one and a half years ahead of the prior plan. Consistent with our prior three-year plan, infrastructure spending for full field development on water handling, anchor batteries, and gathering systems is still expected to be completed by year-end 2028.

Viking

The capital program includes continued light oil development in the Viking with plans to bring 66.1 net wells on production in 2027 with approximately 70 net wells drilled per year through the three-year plan. The Viking is highly repeatable and has strong operating netbacks, contributing meaningful free cash flow within our portfolio.

Heavy Oil

The 2027 heavy oil development program is focused on efficient development, advancing a deep inventory set and further investment in enhanced oil recovery. A total of 130 heavy oil wells are expected to be brought onstream, supporting modest production growth to approximately 48,000 boe/d while generating strong free cash flow.

The 2027 plan includes five rigs running across the heavy oil fairway. At Peavine, multi-lateral horizontal Clearwater development is expected to bring 32 wells onstream while leaving optionality for waterflood development. Development at Lloydminster, primarily within the Mannville stack in northeast Alberta, includes plans to bring 78 wells onstream using a combination of open-hole, multi-lateral and circulation string wells. Multi-lateral horizontal drilling at Peace River will target the Bluesky and Spirit River formations with plans to bring approximately 20 wells onstream.

The three-year heavy oil development plan focuses on the Clearwater at Peavine, the Mannville stack in northeast Alberta, and Spirit River and Bluesky at Peace River. Active development across the heavy oil portfolio is expected to deliver modest production growth and meaningful asset level free cash flow. Exploration activity, including targeted appraisal wells and seismic programs, are planned to expand inventory and support future development.

Enhanced Oil Recovery and Modular SAGD

In 2027, $35 million is allocated to expanded polymer flood development at Lloydminster. Investment in enhanced oil recovery will continue through the three-year plan with the goal of moderating decline and lower sustaining capital requirements.

Gemini thermal has been in the portfolio for more than a decade. A successful pilot was completed in 2014 and there is regulatory approval in place for a 5,000 bbl/d first phase of development. The 2027 capital plan includes $10 million to advance technical characterization of the reservoir and for engineering and design of a central processing facility. The three-year plan will be updated to reflect incremental development plans for Gemini thermal following a final investment decision, targeted for the second half of 2027.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and nine months ended September 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.

Conference Call Tomorrow
10:00 a.m. AT (11:00 a.m. ET)

Baytex will host a conference call tomorrow, November 6, 2026, starting at 10:00am AT (11:00am ET). To participate, please dial toll free in North America 1-833-821-2925 or international 1-647-846-2449. Alternatively, to listen to the conference call online, please enter https://event.choruscall.com/mediaframe/webcast.html?webcastid=jGHCxsPD in your web browser. To register, visit our website at https://www.baytexenergy.com/investors/events-presentations.

An archived recording of the conference call will be available shortly after the event by accessing the webcast link above. The conference call will also be archived on the Baytex website at www.baytexenergy.com.

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: annual production growth of 8 to 10% in the three year outlook; the timing to achieve a break-even target of US$50/bbl WTI; expected exploration and development expenditures for 2026 through 2029 and production for 2026, 2027, Q4/2027 and 2029 and associated comparative growth rates; that Duvernay production will be 25,000 per day by H2/2028 and the amount of hold flat inventory remaining; plans for waterflood and polymer flood development in 2026 and 2027 and potential final investment decision on our Gemini project in H2/2027; anticipated benefits of our Gemini project including our expectations that SAGD will expand our resource with long-life low decline production; targeted annual total shareholder return of 15% at US$70 WTI; plans with respect to wells to be drilled or brought on-stream in Duvernay and Heavy Oil; our 2026 guidance, including exploration and development expenditures, production, average royalty rate, and expenses (operating and transportation); the timing and allocation of our 2027 exploration and development spending, the initial allocation of $150 million to the NCIB in 2027 and expectations that the quarterly dividend will be maintained; Baytex's 3-year outlook including production growth rate, impact on profitability, cost structure, declines, sustaining capital requirements, breakevens, and free cash flow generation; through the outlook, the projected net cash position and 15% total shareholder return through growth, share buybacks and a dividend; 2027 plans with respect to, production growth from heavy oil and the Duvernay, expectations regarding free cash flow generation from heavy oil, Baytex's net cash position and expectations for excess free cash flow; for 2027 and the three year outlook, planned and potential exploration, development and production activities, including production rates, number of wells expected to be drilled and brought on stream in certain areas, spending on infrastructure, enhanced oil recovery and modular SAGD. 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 products; 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 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 target a 15% annual total shareholder return through our 3 year outlook; and our intentions regarding the allocation of $150 million to our NCIB in 2027 and the intent to maintain a quarterly dividend; 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			Nine Months Ended	
($ thousands)	**September 30, 2026**	June 30, 2026	September 30, 2025	**September 30, 2026**	September 30, 2025
Petroleum and natural gas sales	**$ 605,859**	$ 639,943	$ 437,905	**$ 1,698,756**	$ 1,303,092
Blending and other expense	**(54,380)**	(75,068)	(49,750)	**(205,369)**	(184,951)
Total sales, net of blending and other expense	**$ 551,479**	$ 564,875	$ 388,155	**$ 1,493,387**	$ 1,118,141
Royalties	**(94,469)**	(90,378)	(53,645)	**(236,436)**	(160,701)
Operating expense	**(84,377)**	(89,843)	(84,994)	**(255,464)**	(248,609)
Transportation expense	**(23,078)**	(25,932)	(23,060)	**(72,144)**	(62,383)
Operating netback - Canada	**$ 349,555**	$ 358,722	$ 226,456	**$ 929,343**	$ 646,448

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			Nine Months Ended	
($ thousands)	**September 30, 2026**	June 30, 2026	September 30, 2025	**September 30, 2026**	September 30, 2025
Cash flows from operating activities	**$ 283,034**	$ 230,852	$ 472,676	**$ 636,089**	$ 1,258,305
Change in non-cash working capital	**44,330**	21,648	(55,961)	**92,281**	(17,885)
Additions to exploration and evaluation assets	**(1,107)**	—	—	**(2,844)**	(930)
Additions to oil and gas properties	**(185,322)**	(122,242)	(270,364)	**(450,839)**	(1,031,063)
Payments on lease obligations	**(2,429)**	(2,213)	(3,663)	**(6,431)**	(10,022)
Free cash flow	**$ 138,506**	$ 128,045	$ 142,688	**$ 268,256**	$ 198,405

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 September 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)	**September 30, 2026**	June 30, 2026	September 30, 2025
Cash	**$ (652,602)**	$ (720,337)	$ (10,417)
Trade receivables	**(244,000)**	(188,260)	(324,287)
Prepaids and other assets	**(58,498)**	(60,714)	(75,100)
Inventory	**(1,624)**	(8,756)	—
Trade payables	**289,861**	275,032	554,057
Share-based compensation liability	**37,907**	29,498	24,666
Dividends payable	**15,578**	16,144	17,326
Other long-term liabilities	**—**	—	20,163
Working capital (surplus) deficiency	**$ (613,378)**	$ (657,393)	$ 206,408

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)	**September 30, 2026**	June 30, 2026	September 30, 2025
Credit facilities	**$ —**	$ —	$ 166,841
Unamortized debt issuance costs - Credit facilities [(1)]	**—**	—	15,504
Long-term notes	**89,201**	89,229	1,815,230
Unamortized debt issuance costs - Long-term notes [(1)]	**1,810**	1,878	40,375
Trade payables	**289,861**	275,032	554,057
Share-based compensation liability	**37,907**	29,498	24,666
Dividends payable	**15,578**	16,144	17,326
Other long-term liabilities	**—**	—	20,163
Cash	**(652,602)**	(720,337)	(10,417)
Trade receivables	**(244,000)**	(188,260)	(324,287)
Prepaids and other assets	**(58,498)**	(60,714)	(75,100)
Inventory	**(1,624)**	(8,756)	—
Net (cash) debt	**$ (522,367)**	$ (566,286)	$ 2,244,358

(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			Nine Months Ended	
($ thousands)	**September 30, 2026**	June 30, 2026	September 30, 2025	**September 30, 2026**	September 30, 2025
Cash flow from operating activities	**$ 283,034**	$ 230,852	$ 472,676	**$ 636,089**	$ 1,258,305
Change in non-cash working capital	**44,330**	21,648	(55,961)	**92,281**	(17,885)
Asset retirement obligations settled	**4,520**	1,933	5,517	**9,072**	12,601
Adjusted funds flow	**$ 331,884**	$ 254,433	$ 422,232	**$ 737,442**	$ 1,253,021

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 acreage and an assumption as to the number of wells that can be drilled per section based on preliminary development plans. Unbooked locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. Unbooked locations do not have attributed reserves. Risked unbooked locations are based on the chance of commerciality, which incorporates contingencies including geologic uncertainty, economic status, regulatory approvals, infrastructure and market considerations, timing of production and development. There is no certainty that we will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The wells developed will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relatively close proximity to such unbooked drilling locations, other unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that 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 risked 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 risked 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 nine months ended September 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 September 30, 2026					Three Months Ended September 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	9,699	11	19	7,871	11,040	9,900	13	38	10,079	11,631
Lloydminster	15,603	6	—	1,185	15,807	13,260	26	1	1,224	13,491
Peavine	18,581	—	—	—	18,581	20,953	—	—	—	20,953
Remaining Properties	426	1	—	437	500	1,094	3	—	648	1,205
Canada - Light										
Viking	28	8,243	251	8,453	9,931	56	7,500	210	9,832	9,404
Duvernay	—	6,392	3,792	15,730	12,806	—	4,824	3,068	13,758	10,185
Remaining Properties	4	238	657	12,250	2,941	6	239	168	5,420	1,316
Total Canada	44,341	14,891	4,719	45,926	71,606	45,269	12,605	3,485	40,961	68,185
United States										
Eagle Ford	—	—	—	—	—	—	52,330	15,582	89,115	82,765
Total	44,341	14,891	4,719	45,926	71,606	45,269	64,935	19,067	130,076	150,950

	Nine Months Ended September 30, 2026					Nine Months Ended September 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	9,674	8	22	8,270	11,082	9,805	13	30	9,850	11,490
Lloydminster	15,718	6	—	1,210	15,926	12,362	20	—	1,188	12,580
Peavine	19,232	—	—	—	19,232	19,455	—	—	—	19,455
Remaining Properties	544	2	—	586	644	1,113	2	—	687	1,229
Canada - Light										
Viking	23	8,185	254	9,279	10,009	85	8,015	187	10,302	10,004
Duvernay	—	4,480	3,434	13,437	10,154	—	3,478	2,488	9,485	7,547
Remaining Properties	6	317	790	15,747	3,737	5	324	494	10,823	2,627

Total Canada	45,197	12,998	4,500	48,529	70,784	42,825	11,852	3,199	42,335	64,932
United States										
Eagle Ford	—	—	—	—	—	—	51,284	16,154	92,407	82,839
Total	45,197	12,998	4,500	48,529	70,784	42,825	63,136	19,353	134,742	147,771

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
President and Chief Executive Officer
Baytex Energy Corp.

Chad Kalmakoff
Chief Financial Officer
Baytex Energy Corp.

Chris Lessoway
Vice President, Finance and Treasurer
Baytex Energy Corp.

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

Baytex Energy Corp.
Management's Discussion and Analysis
For the three and nine months ended September 30, 2026 and 2025
Dated November 5, 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 nine months ended September 30, 2026. This information is provided as of November 5, 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 nine months ended September 30, 2026 ("Q3/2026" and "YTD 2026") have been compared with the results for the three and nine months ended September 30, 2025 ("Q3/2025" 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 nine months ended September 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 heavy oil assets in Peace River and Lloydminster along with Duvernay and Viking light oil assets.

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 operations and its results are classified as discontinued operations. The financial results for the three and nine months ended September 30, 2026 and September 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 September 30					
	2026			2025		
	Continuing	**Discontinued**	**Total**	Continuing	Discontinued	Total
Revenue, net of royalties						
Petroleum and natural gas sales	**$ 605,859**	**$ —**	**$ 605,859**	$ 437,905	$ 489,743	$ 927,648
Royalties	**(94,469)**	**—**	**(94,469)**	(53,645)	(127,585)	(181,230)
	511,390	**—**	**511,390**	384,260	362,158	746,418
Expenses						
Operating	**84,377**	**—**	**84,377**	84,994	75,290	160,284
Transportation	**23,078**	**—**	**23,078**	23,060	12,235	35,295
Blending and other	**54,380**	**—**	**54,380**	49,750	—	49,750
General and administrative	**12,445**	**—**	**12,445**	15,824	4,912	20,736
Exploration and evaluation	**50**	**—**	**50**	127	—	127
Depletion and depreciation	**131,138**	**—**	**131,138**	126,218	202,875	329,093
Share-based compensation	**9,166**	**—**	**9,166**	8,440	2,297	10,737
Net financing and interest expense	**4,669**	**—**	**4,669**	47,062	5,374	52,436
Financial derivatives (gain) loss	**(10,880)**	**—**	**(10,880)**	5,039	—	5,039
Foreign exchange loss	**368**	**—**	**368**	36,921	—	36,921
Gain on dispositions	**(7,906)**	**—**	**(7,906)**	(1,591)	—	(1,591)
Other expense (income)	**1,883**	**—**	**1,883**	702	(119)	583
	302,768	**—**	**302,768**	396,546	302,864	699,410
Net income (loss) before income taxes	**208,622**	**—**	**208,622**	(12,286)	59,294	47,008
Income taxes						
Current income tax expense (recovery)	**25**	**—**	**25**	1,076	(6,809)	(5,733)
Deferred income tax expense	**48,329**	**—**	**48,329**	15,089	5,684	20,773
	48,354	**—**	**48,354**	16,165	(1,125)	15,040
Net income (loss)	**$ 160,268**	**$ —**	**$ 160,268**	$ (28,451)	$ 60,419	$ 31,968

	Nine Months Ended September 30					
	2026			2025		
	Continuing	**Discontinued**	**Total**	Continuing	Discontinued	Total
Revenue, net of royalties						
Petroleum and natural gas sales	**$ 1,698,756**	**$ —**	**$ 1,698,756**	$ 1,303,092	$ 1,510,265	$ 2,813,357
Royalties	**(236,436)**	**—**	**(236,436)**	(160,701)	(405,856)	(566,557)
	1,462,320	**—**	**1,462,320**	1,142,391	1,104,409	2,246,800
Expenses						
Operating	**255,464**	**—**	**255,464**	248,609	220,398	469,007
Transportation	**72,144**	**—**	**72,144**	62,383	36,331	98,714
Blending and other	**205,369**	**—**	**205,369**	184,951	—	184,951
General and administrative	**51,224**	**—**	**51,224**	50,985	17,577	68,562
Exploration and evaluation	**1,525**	**—**	**1,525**	691	—	691
Depletion and depreciation	**383,773**	**—**	**383,773**	360,965	610,210	971,175
Share-based compensation	**36,353**	**—**	**36,353**	9,716	3,339	13,055
Net financing and interest expense	**12,282**	**—**	**12,282**	144,498	14,897	159,395
Financial derivatives loss	**118,433**	**—**	**118,433**	35,995	—	35,995
Foreign exchange loss (gain)	**1,986**	**—**	**1,986**	(67,543)	—	(67,543)
Gain on dispositions	**(10,184)**	**(19,720)**	**(29,904)**	(1,028)	—	(1,028)
Other expense (income)	**5,644**	**—**	**5,644**	5,801	(3,344)	2,457
	1,134,013	**(19,720)**	**1,114,293**	1,036,023	899,408	1,935,431
Net income before income taxes	**328,307**	**19,720**	**348,027**	106,368	205,001	311,369
Income taxes						
Current income tax expense (recovery)	**25**	**1,086**	**1,111**	8,061	(7,095)	966
Deferred income tax expense	**79,105**	**—**	**79,105**	41,095	16,200	57,295
	79,130	**1,086**	**80,216**	49,156	9,105	58,261
Net income	**$ 249,177**	**$ 18,634**	**$ 267,811**	$ 57,212	$ 195,896	$ 253,108

THIRD QUARTER HIGHLIGHTS

Baytex delivered strong operating and financial results in Q3/2026. Production of 71,606 boe/d and exploration and development expenditures of $186.4 million for Q3/2026 were consistent with our full-year plan. During the quarter, we brought 46.9 net wells on production and continued to advance our 2026 development program, which is focused on our heavy oil and Duvernay properties.

We generated adjusted funds flow[(1)] of $331.9 million and cash flows from operating activities of $283.0 million, compared to adjusted funds flow from continuing operations of $151.8 million and cash flows from operating activities from continuing operations of $178.9 million in Q3/2025.

We generated free cash flow[(2)] of $138.5 million in Q3/2026, reflecting the disciplined execution of our exploration and development programs while maintaining a strong net cash[(1)] position of $522.4 million at period end. During the quarter, we repurchased 24.1 million common shares for $152.0 million under our normal course issuer bid and declared a quarterly dividend of $0.0225 per share.

Net cash[(1)] was $522.4 million at September 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

We continue to execute our 2026 plan and anticipate full year 2026 production of approximately 71,000 boe/d. Guidance for exploration and development expenditures, average royalty rate, operating expense, and transportation expense has been revised to reflect year-to-date results and our expectation for the fourth quarter.

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	~ $665 million	$453.7 million
Production (boe/d) [(2)]	~ 71,000	No change	70,784
Expenses:			
Average royalty rate [(3)(4)]	15%	16 %	15.8 %
Operating [(3)(5)]	$13.75 - $14.25/boe	$13.30/boe	$13.22/boe
Transportation [(3)(5)]	$3.40 - $3.60/boe	$3.75/boe	$3.73/boe
Leasing expenditures [(3)]	$7 million	No change	$6.4 million
Asset retirement obligations settled [(3)]	$20 million	No change	$9.1 million

(1) As announced on May 7, 2026.
(2) As announced July 30, 2026.
(3) As announced on December 22, 2025.
(4) 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.
(5) 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 September 30			Nine Months Ended September 30		
	2026	2025	Change	**2026**	2025	Change
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**14,891**	12,605	18%	**12,998**	11,852	10%
Heavy oil	**44,341**	45,269	(2)%	**45,197**	42,825	6%
Natural Gas Liquids (NGL)	**4,719**	3,485	35%	**4,500**	3,199	41%
Total liquids (bbl/d)	**63,951**	61,359	4%	**62,695**	57,876	8%
Natural gas (mcf/d)	**45,926**	40,961	12%	**48,529**	42,335	15%
Daily production (boe/d) - continuing operations	**71,606**	68,185	5%	**70,784**	64,932	9%
Daily production (boe/d) - discontinued operations	**—**	82,765	(100)%	**—**	82,839	(100)%
Total production (boe/d)	**71,606**	150,950	(53)%	**70,784**	147,771	(52)%
Production Mix - continuing operations						
Light oil and condensate	**20 %**	19 %	1 %	**19 %**	18 %	1 %
Heavy oil	**62 %**	66 %	(4)%	**64 %**	66 %	(2)%
NGL	**7 %**	5 %	2 %	**6 %**	5 %	1 %
Natural gas	**11 %**	10 %	1 %	**11 %**	11 %	— %

Production from continuing operations of 71,606 boe/d for Q3/2026 and 70,784 boe/d for YTD 2026 increased 5% and 9% respectively compared to 68,185 boe/d for Q3/2025 and 64,932 boe/d for YTD 2025 with strong performance from both our heavy oil and Duvernay development programs over the last year.

Total production of 70,784 boe/d for YTD 2026 is consistent with 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 September 30			Nine Months Ended September 30		
	2026	2025	Change	**2026**	2025	Change
WTI oil (US$/bbl) [(1)]	**85.79**	64.93	20.86	**83.50**	66.70	16.80
Edmonton par oil ($/bbl) [(2)]	**119.21**	86.20	33.01	**114.99**	88.54	26.45
Edmonton par oil differential to WTI (US$/bbl)	**(0.57)**	(2.35)	1.78	**(0.46)**	(3.40)	2.94
WCS heavy oil ($/bbl) [(3)]	**100.59**	75.14	25.45	**95.95**	77.80	18.15
WCS heavy oil differential to WTI (US$/bbl)	**(13.88)**	(10.38)	(3.50)	**(14.21)**	(11.08)	(3.13)
AECO 7A natural gas price ($/mcf) [(4)]	**1.54**	1.00	0.54	**1.85**	1.70	0.15
AECO 5A natural gas price ($/mcf) [(5)]	**1.57**	0.63	0.94	**1.74**	1.50	0.24
CAD/USD average exchange rate	**1.3988**	1.3774	0.0214	**1.3847**	1.3988	(0.0141)

(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$85.79/bbl for Q3/2026 and US$83.50/bbl for YTD 2026 compared to US$64.93/bbl for Q3/2025 and US$66.70/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 demand for heavy oil as well as 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 $119.21/bbl during Q3/2026 and $114.99/bbl for YTD 2026 compared to $86.20/bbl during Q3/2025 and $88.54/bbl for YTD 2025. Edmonton par differentials strengthened in 2026 as Canadian light oil benefited from tighter global light crude and refined product markets. Edmonton par traded at a discount to WTI of US$0.57/bbl for Q3/2026 and US$0.46/bbl for YTD 2026, compared to discounts of US$2.35/bbl for Q3/2025 and US$3.40/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 $100.59/bbl for Q3/2026 and $95.95/bbl for YTD 2026 compared to $75.14/bbl for Q3/2025 and $77.80/bbl for YTD 2025. The WCS heavy oil differential to WTI was US$13.88/bbl in Q3/2026 and US$14.21/bbl for YTD 2026 which was wider compared to US$10.38/bbl for Q3/2025 and US$11.08/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 $1.54/mcf during Q3/2026 and $1.85/mcf during YTD 2026 compared to $1.00/mcf for Q3/2025 and $1.70/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 September 30			Nine Months Ended September 30		
	2026	2025	Change	**2026**	2025	Change
Light oil and condensate ($/bbl) [1]	**$ 118.44**	$ 85.53	$ 32.91	**$ 112.19**	$ 87.32	$ 24.87
Heavy oil, net of blending and other expense ($/bbl) [2]	**91.26**	67.05	24.21	**84.57**	68.17	16.40
NGL ($/bbl) [1]	**24.62**	22.62	2.00	**24.59**	24.47	0.12
Natural gas ($/mcf) [1]	**1.47**	0.65	0.82	**1.63**	1.49	0.14
Total sales, net of blending and other expense ($/boe) [2] - continuing operations	**$ 83.71**	$ 61.88	$ 21.83	**$ 77.28**	$ 63.08	$ 14.20
Total sales ($/boe) - discontinued operations	**—**	64.32	(64.32)	**—**	66.78	(66.78)
Total sales, net of blending and other expense ($/boe) [2]	**$ 83.71**	$ 63.22	$ 20.49	**$ 77.28**	$ 65.15	$ 12.13

(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 $83.71/boe for Q3/2026 and $77.28/boe for YTD 2026 compared to $61.88/boe for Q3/2025 and $63.08/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 $0.77/bbl for Q3/2026 and $2.80/bbl for YTD 2026 compared to a discount of $0.67/bbl in Q3/2025 and $1.22/bbl in YTD 2025. The narrower discount in Q3/2026 is more reflective of normal operations compared to the wider discount in YTD 2026 which reflects the timing of production along with the increase in benchmark oil prices later in Q1 2026.

Our realized heavy oil price, net of blending and other expense for continuing operations was higher in Q3/2026 and YTD 2026 compared to the same periods of 2025 which reflects the increase in WCS benchmark pricing. Our realized pricing for Q3/2026 and YTD 2026 represents a discount to the WCS benchmark of $9.33/bbl and $11.38/bbl respectively compared to $8.09/bbl Q3/2025 and $9.63/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 Q3/2026 and YTD 2026 compared to 25% of WTI in Q3/2025 and 26% 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 $1.47/mcf for Q3/2026 and $1.63/mcf for YTD 2026 was higher than $0.65/mcf for Q3/2025 and $1.49/mcf for YTD 2025, consistent with the increase in AECO benchmark pricing.

PETROLEUM AND NATURAL GAS SALES

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2026**	2025	Change	**2026**	2025	Change
Oil sales						
Light oil and condensate	**$ 162,266**	$ 99,188	$ 63,078	**$ 398,126**	$ 282,532	$ 115,594
Heavy oil	**426,675**	329,005	97,670	**1,248,844**	981,970	266,874
NGL	**10,690**	7,250	3,440	**30,210**	21,371	8,839
Total oil sales	**599,631**	435,443	164,188	**1,677,180**	1,285,873	391,307
Natural gas sales	**6,228**	2,462	3,766	**21,576**	17,219	4,357
Total petroleum and natural gas sales	**605,859**	437,905	167,954	**1,698,756**	1,303,092	395,664
Blending and other expense	**(54,380)**	(49,750)	(4,630)	**(205,369)**	(184,951)	(20,418)
Total sales, net of blending and other expense [(1)] - continuing operations	**$ 551,479**	$ 388,155	$ 163,324	**$ 1,493,387**	$ 1,118,141	$ 375,246
Total sales - discontinued operations	**—**	489,743	(489,743)	**—**	1,510,265	(1,510,265)
Total sales, net of blending and other expense [(1)]	**$ 551,479**	$ 877,898	$ (326,419)	**$ 1,493,387**	$ 2,628,406	$(1,135,019)

(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 $551.5 million for Q3/2026 and $1,493.4 million for YTD 2026 compared to $388.2 million for Q3/2025 and $1,118.1 million for YTD 2025. The increase in total sales, net of blending and other expense reflects higher realized pricing and higher production in both Q3/2026 and YTD 2026. The increase in our realized pricing for Q3/2026 relative to Q3/2025 resulted in a $143.8 million increase in total sales, net of blending and other expense, and higher production contributed a $19.5 million increase in total sales, net of blending and other expense. Higher realized pricing resulted in a $274.4 million increase in total sales, net of blending and other expense, in YTD 2026 relative to YTD 2025 while higher production contributed an $100.8 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 nine months ended September 30, 2026 and 2025.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for % and per boe)	**2026**	2025	Change	**2026**	2025	Change
Royalties - continuing operations	**$ 94,469**	$ 53,645	$ 40,824	**$ 236,436**	$ 160,701	$ 75,735
Royalties - discontinued operations	**—**	127,585	(127,585)	**—**	405,856	(405,856)
Total royalties	**$ 94,469**	$ 181,230	$ (86,761)	**$ 236,436**	$ 566,557	$(330,121)
Average royalty rate [(1)] - continuing operations	**17.1 %**	13.8 %	3.3 %	**15.8 %**	14.4 %	1.4 %
Average royalty rate [(1)] - discontinued operations	**— %**	26.1 %	(26.1)%	**— %**	26.9 %	(26.9)%
Total average royalty rate [(1)]	**17.1 %**	20.6 %	(3.5)%	**15.8 %**	21.6 %	(5.8)%
Royalties per boe [(2)] - continuing operations	**$ 14.34**	$ 8.55	$ 5.79	**$ 12.24**	$ 9.07	$ 3.17
Royalties per boe [(2)] - discontinued operations	**$ —**	$ 16.76	$ (16.76)	**$ —**	$ 17.95	$ (17.95)
Total royalties per boe [(2)]	**$ 14.34**	$ 13.05	$ 1.29	**$ 12.24**	$ 14.04	$ (1.80)

(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 $94.5 million or 17.1% of total sales, net of blending and other expense for Q3/2026 compared to $53.6 million or 13.8% for Q3/2025. Royalties for continuing operations were $236.4 million or 15.8% of total sales, net of blending and other expense for YTD 2026 compared to $160.7 million or 14.4% for YTD 2025. Our average royalty rate was higher for Q3/2026 and YTD 2026 as a result of higher benchmark prices.

Our average royalty rate of 15.8% for YTD 2026 is consistent with our revised annual guidance of approximately 16% for 2026.

OPERATING EXPENSE

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2026**	2025	Change	**2026**	2025	Change
Operating expense - continuing operations	**$ 84,377**	$ 84,994	$ (617)	**$ 255,464**	$ 248,609	$ 6,855
Operating expense - discontinued operations	**—**	75,290	(75,290)	**—**	220,398	(220,398)
Total operating expense	**$ 84,377**	$ 160,284	$ (75,907)	**$ 255,464**	$ 469,007	$ (213,543)
Operating expense per boe [(1)] - continuing operations	**$ 12.81**	$ 13.55	$ (0.74)	**$ 13.22**	$ 14.02	$ (0.80)
Operating expense per boe [(1)] - discontinued operations	**$ —**	$ 9.89	$ (9.89)	**$ —**	$ 9.75	$ (9.75)
Total operating expense per boe [(1)]	**$ 12.81**	$ 11.54	$ 1.27	**$ 13.22**	$ 11.63	$ 1.59

(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 $84.4 million ($12.81/boe) for Q3/2026 and $255.5 million ($13.22/boe) for YTD 2026 compared to $85.0 million ($13.55/boe) for Q3/2025 and $248.6 million ($14.02/boe) for YTD 2025. Operating expense for continuing operations for Q3/2026 and YTD 2026 was relatively consistent with both Q3/2025 and YTD 2025 while per unit operating expense decreased as higher production volumes enabled costs to be absorbed over a larger production base.

Operating expense of $13.22/boe for YTD 2026 is consistent with our revised annual guidance of $13.30/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 nine months ended September 30, 2026 and 2025.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2026**	2025	Change	**2026**	2025	Change
Transportation expense - continuing operations	**$ 23,078**	$ 23,060	$ 18	**$ 72,144**	$ 62,383	$ 9,761
Transportation expense - discontinued operations	**—**	12,235	(12,235)	**—**	36,331	(36,331)
Total transportation expense	**$ 23,078**	$ 35,295	$ (12,217)	**$ 72,144**	$ 98,714	$ (26,570)
Transportation expense per boe [(1)] - continuing operations	**$ 3.50**	$ 3.68	$ (0.18)	**$ 3.73**	$ 3.52	$ 0.21
Transportation expense per boe [(1)] - discontinued operations	**$ —**	$ 1.61	$ (1.61)	**$ —**	$ 1.61	$ (1.61)
Total transportation expense per boe [(1)]	**$ 3.50**	$ 2.54	$ 0.96	**$ 3.73**	$ 2.45	$ 1.28

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

Transportation expense for continuing operations was $23.1 million ($3.50/boe) for Q3/2026 and $72.1 million ($3.73/boe) for YTD 2026 compared to $23.1 million ($3.68/boe) for Q3/2025 and $62.4 million ($3.52/boe) for YTD 2025. Transportation expense for continuing operations for Q3/2026 was consistent with Q3/2025 while YTD 2026 increased as a result of higher heavy oil production and an increase in trucking rates relative to 2025.

Transportation expense of $3.73/boe for YTD 2026 is consistent with our revised annual guidance of $3.75/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 $54.4 million for Q3/2026 and $205.4 million for YTD 2026 compared to $49.8 million for Q3/2025 and $185.0 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 as well as higher heavy oil production in YTD 2026 compared to YTD 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 new contracts are entered into.

The following table summarizes the results of our financial derivative contracts for the three and nine months ended September 30, 2026 and 2025.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2026**	2025	Change	**2026**	2025	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ 4,990**	$ (9,203)	$ 14,193	**$ (109,725)**	$ (22,484)	$ (87,241)
Natural gas	**818**	623	195	**2,098**	1,836	262
Total	**$ 5,808**	$ (8,580)	$ 14,388	**$ (107,627)**	$ (20,648)	$ (86,979)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ 6,908**	$ (4,401)	$ 11,309	**$ (8,585)**	$ (20,016)	$ 11,431
Natural gas	**(1,836)**	7,942	(9,778)	**(2,221)**	4,669	(6,890)
Total	**$ 5,072**	$ 3,541	$ 1,531	**$ (10,806)**	$ (15,347)	$ 4,541
Total financial derivatives gain (loss)						
Crude oil	**$ 11,898**	$ (13,604)	$ 25,502	**$ (118,310)**	$ (42,500)	$ (75,810)
Natural gas	**(1,018)**	8,565	(9,583)	**(123)**	6,505	(6,628)
Total	**$ 10,880**	$ (5,039)	$ 15,919	**$ (118,433)**	$ (35,995)	$ (82,438)

We recorded a total financial derivatives gain of $10.9 million for Q3/2026 and a loss of $118.4 million for YTD 2026 compared to losses of $5.0 million for Q3/2025 and $36.0 million for YTD 2025. The realized financial derivatives loss of $107.6 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 $10.8 million for YTD 2026 reflects both the reclassification of unrealized losses to realized losses upon settlement of contracts during 2026 and the increase in forecasted crude oil pricing used to revalue outstanding volumes on crude oil contracts in place at September 30, 2026, relative to December 31, 2025. The fair value of our financial derivative contracts resulted in a net asset of $15.7 million at September 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 November 5, 2026.

OPERATING NETBACK

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

	Three Months Ended September 30			Nine Months Ended September 30		
($ per boe except for volume)	**2026**	2025	Change	**2026**	2025	Change
Daily production (boe/d) - continuing operations	**71,606**	68,185	5 %	**70,784**	64,932	9 %
Daily production (boe/d) - discontinued operations	**—**	82,765	(100)%	**—**	82,839	(100)%
Total production (boe/d)	**71,606**	150,950	(53)%	**70,784**	147,771	(52)%
Operating netback:						
Total sales, net of blending and other expense [(1)]	**$ 83.71**	$ 61.88	$ 21.83	**$ 77.28**	$ 63.08	$ 14.20
Less:						
Royalties [(2)]	**(14.34)**	(8.55)	(5.79)	**(12.24)**	(9.07)	(3.17)
Operating expense [(2)]	**(12.81)**	(13.55)	0.74	**(13.22)**	(14.02)	0.80
Transportation expense [(2)]	**(3.50)**	(3.68)	0.18	**(3.73)**	(3.52)	(0.21)
Operating netback [(1)] - continuing operations	**$ 53.06**	$ 36.10	$ 16.96	**$ 48.09**	$ 36.47	$ 11.62
Operating netback [(1)] - discontinued operations	**—**	36.06	(36.06)	**—**	37.47	(37.47)
Operating netback [(1)]	**$ 53.06**	$ 36.09	$ 16.97	**$ 48.09**	$ 37.03	$ 11.06
Realized financial derivatives gain (loss) [(3)]	**0.88**	(0.62)	1.50	**(5.57)**	(0.51)	(5.06)
Operating netback after financial derivatives [(1)]	**$ 53.94**	$ 35.47	$ 18.47	**$ 42.52**	$ 36.52	$ 6.00

(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 of 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 $53.06/boe for Q3/2026 and $48.09/boe for YTD 2026 was higher than $36.10/boe for Q3/2025 and $36.47/boe for YTD 2025 due to the increase in our realized price which resulted in higher per unit sales net of royalties. Our operating netback after financial derivatives of $53.94/boe for Q3/2026 and $42.52/boe for YTD 2026 was higher than $35.47/boe for Q3/2025 and $36.52/boe for YTD 2025 due to higher realized pricing.

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 nine months ended September 30, 2026 and 2025.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2026**	2025 [1]	Change	**2026**	2025 [1]	Change
Gross G&A expense - continuing operations	**$ 14,616**	$ 17,533	$ (2,917)	**$ 56,723**	$ 56,336	$ 387
Overhead recoveries - continuing operations	**(2,171)**	(1,709)	(462)	**(5,499)**	(5,351)	(148)
G&A expense - continuing operations	**$ 12,445**	$ 15,824	$ (3,379)	**$ 51,224**	$ 50,985	$ 239
G&A expense - discontinued operations [2]	**—**	4,912	(4,912)	**—**	17,577	(17,577)
Total G&A expense	**$ 12,445**	$ 20,736	$ (8,291)	**$ 51,224**	$ 68,562	$ (17,338)
G&A expense per boe [3] - continuing operations	**$ 1.89**	$ 2.52	$ (0.63)	**$ 2.65**	$ 2.88	$ (0.23)
G&A expense per boe [3] - discontinued operations	**$ —**	$ 0.65	$ (0.65)	**$ —**	$ 0.78	$ (0.78)
Total G&A expense per boe [3]	**$ 1.89**	$ 1.49	$ 0.40	**$ 2.65**	$ 1.70	$ 0.95

(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 $12.4 million ($1.89/boe) for Q3/2026 and $51.2 million ($2.65/boe) for YTD 2026 compared to $15.8 million ($2.52/boe) for Q3/2025 and $51.0 million ($2.88/boe) for YTD 2025. G&A expense for continuing operations for YTD 2026 was consistent with YTD 2025 while Q3/2026 decreased compared to Q3/2025 due to savings realized in professional fees and insurance costs, as well as reduced personnel costs. G&A expense for continuing operations for YTD 2026 includes severance and other non-recurring costs related to staff reductions in Canada which resulted in higher G&A expense per boe for YTD 2026 compared to Q3/2026.

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 nine months ended September 30, 2026 and 2025.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2026**	2025 [1]	Change	**2026**	2025 [1]	Change
Interest on credit facilities	**$ 827**	$ 2,951	$ (2,124)	**$ 2,556**	$ 9,790	$ (7,234)
Interest on long-term notes	**1,676**	36,718	(35,042)	**5,031**	114,680	(109,649)
Interest on lease obligations	**1,423**	323	1,100	**3,961**	985	2,976
Interest income	**(4,466)**	(86)	(4,380)	**(15,544)**	(478)	(15,066)
Net cash interest (income) expense	**$ (540)**	$ 39,906	$ (40,446)	**$ (3,996)**	$ 124,977	$ (128,973)
Amortization of debt issue costs	**63**	2,217	(2,154)	**642**	8,121	(7,479)
Accretion of asset retirement obligations	**5,146**	4,939	207	**15,339**	14,155	1,184
Early redemption expense (gain)	**—**	—	—	**297**	(2,755)	3,052
Net financing and interest expense - continuing operations	**$ 4,669**	$ 47,062	$ (42,393)	**$ 12,282**	$ 144,498	$ (132,216)
Net financing and interest expense - discontinued operations	**—**	5,374	(5,374)	**—**	14,897	(14,897)
Total net financing and interest expense	**$ 4,669**	$ 52,436	$ (47,767)	**$ 12,282**	$ 159,395	$ (147,113)
Net financing and interest expense per boe [2] - continuing operations	**$ 0.71**	$ 7.50	$ (6.79)	**$ 0.64**	$ 8.15	$ (7.51)
Net financing and interest expense per boe [2] - discontinued operations	**$ —**	$ 0.71	$ (0.71)	**$ —**	$ 0.66	$ (0.66)
Total net financing and interest expense per boe [2]	**$ 0.71**	$ 3.78	$ (3.07)	**$ 0.64**	$ 3.95	$ (3.31)

(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 $4.7 million ($0.71/boe) for Q3/2026 and $12.3 million ($0.64/boe) for YTD 2026 compared to $47.1 million ($7.50/boe) for Q3/2025 and $144.5 million ($8.15/boe) for YTD 2025. Lower net financing and interest expense for Q3/2026 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 $0.5 million for Q3/2026 and $4.0 million for YTD 2026 compared to interest expense of $39.9 million for Q3/2025 and $125.0 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 Q3/2026 and YTD 2026. Interest on our credit facilities for Q3/2026 and YTD 2026 reflects the standby fees rate of 0.5% compared to the weighted average interest rate of 6.7% for Q3/2025 and YTD 2025. Interest income for Q3/2026 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 $5.1 million for Q3/2026 and $15.3 million for YTD 2026 was consistent with $4.9 million for Q3/2025 and $14.2 million for YTD 2025. Amortization of debt issue costs for continuing operations of $0.1 million for Q3/2026 and $0.6 million for YTD 2026 was lower than $2.2 million for Q3/2025 and $8.1 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 $0.1 million for Q3/2026 and $1.5 million for YTD 2026 compared to $0.1 million for Q3/2025 and $0.7 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 nine months ended September 30, 2026 and 2025.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2026**	2025 [1]	Change	**2026**	2025 [1]	Change
Depletion and depreciation - continuing operations	**$ 131,138**	$ 126,218	$ 4,920	**$ 383,773**	$ 360,965	$ 22,808
Depletion and depreciation - discontinued operations	**—**	202,875	(202,875)	**—**	610,210	(610,210)
Total depletion and depreciation	**$ 131,138**	$ 329,093	$ (197,955)	**$ 383,773**	$ 971,175	$ (587,402)
Depletion and depreciation per boe [2] - continuing operations	**$ 19.91**	$ 20.12	$ (0.21)	**$ 19.86**	$ 20.36	$ (0.50)
Depletion and depreciation per boe [2] - discontinued operations	**$ —**	$ 26.64	$ (26.64)	**$ —**	$ 26.98	$ (26.98)
Total depletion and depreciation per boe [2]	**$ 19.91**	$ 23.70	$ (3.79)	**$ 19.86**	$ 24.07	$ (4.21)

(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 $131.1 million ($19.91/boe) for Q3/2026 and $383.8 million ($19.86/boe) for YTD 2026 compared to $126.2 million ($20.12/boe) for Q3/2025 and $361.0 million ($20.36/boe) for YTD 2025. Depletion and depreciation expense for continuing operations was higher in Q3/2026 and YTD 2026 relative to Q3/2025 and YTD 2025 due to higher production.

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 September 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-settled 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 $9.2 million for Q3/2026 and $36.4 million for YTD 2026 for our continuing operations compared to $8.4 million for Q3/2025 and $9.7 million for YTD 2025. The increase for Q3/2026 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 YTD 2026 for continuing operations is comprised of $31.5 million of cash expense and $4.9 million of non-cash expense for awards designated as equity-settled.

FOREIGN EXCHANGE

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

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for exchange rates)	**2026**	2025	Change	**2026**	2025	Change
Unrealized foreign exchange (gain) loss	**$ (132)**	$ 36,840	$ (36,972)	**$ 3,191**	$ (67,427)	$ 70,618
Realized foreign exchange loss (gain)	**500**	81	419	**(1,205)**	(116)	(1,089)
Foreign exchange loss (gain) - continuing operations	**$ 368**	$ 36,921	$ (36,553)	**$ 1,986**	$ (67,543)	$ 69,529
CAD/USD exchange rates:						
At beginning of period	**1.4206**	1.3622		**1.3715**	1.4405	
At end of period	**1.4191**	1.3906		**1.4191**	1.3906	

We recorded a foreign exchange loss for continuing operations of $0.4 million for Q3/2026 and $2.0 million for YTD 2026 compared to a loss of $36.9 million for Q3/2025 and a gain of $67.5 million for YTD 2025.

The unrealized foreign exchange gain for continuing operations of $0.1 million for Q3/2026 and the loss of $3.2 million for YTD 2026 is related to changes in the reported amount of our U.S. dollar denominated long-term notes due to changes in the value of the Canadian dollar relative to the U.S. dollar at September 30, 2026 compared to June 30, 2026 and December 31, 2025. The unrealized foreign exchange loss of $36.8 million for Q3/2025 and gain of $67.4 million for YTD 2025 is related to changes in the reported amount of our long-term notes and credit facilities due to changes in the value of the Canadian dollar relative to the U.S. dollar at September 30, 2025 compared to June 30, 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 loss for continuing operations of $0.5 million for Q3/2026 and a gain of $1.2 million for YTD 2026 compared to a loss of $0.1 million for Q3/2025 and a gain of $0.1 million for YTD 2025.

INCOME TAXES

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2026**	2025 [(1)]	Change	**2026**	2025 [(1)]	Change
Current income tax expense	**$ 25**	$ 1,076	$ (1,051)	**$ 25**	$ 8,061	$ (8,036)
Deferred income tax expense	**48,329**	15,089	33,240	**79,105**	41,095	38,010
Income tax expense - continuing operations	**$ 48,354**	$ 16,165	$ 32,189	**$ 79,130**	$ 49,156	$ 29,974
Income tax (recovery) expense - discontinued operations	**$ —**	$ (1,125)	$ 1,125	**$ —**	$ 9,105	$ (9,105)

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

We recorded current income tax expense for continuing operations of $25 thousand in Q3/2026 and YTD 2026 compared to an expense of $1.1 million for Q3/2025 and $8.1 million for YTD 2025. Current income tax expense for Q3/2025 and YTD 2025 relates to the financing structure previously utilized in connection with our Eagle Ford operations.

We recorded a deferred income tax expense for continuing operations of $48.3 million for Q3/2026 and $79.1 million for YTD 2026 compared to expense of $15.1 million for Q3/2025 and $41.1 million for YTD 2025. The deferred tax expense for Q3/2026 and YTD 2026 reflects an effective tax rate of 23.2% and 24.1% which is similar to our statutory rate of 24.0%.

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 nine months ended September 30, 2026 and 2025 are set forth in the following table.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2026**	2025 [1]	Change	**2026**	2025 [1]	Change
Petroleum and natural gas sales	**$ 605,859**	$ 437,905	$ 167,954	**$ 1,698,756**	$ 1,303,092	$ 395,664
Royalties	**(94,469)**	(53,645)	(40,824)	**(236,436)**	(160,701)	(75,735)
Revenue, net of royalties	**511,390**	384,260	127,130	**1,462,320**	1,142,391	319,929
Expenses						
Operating	**(84,377)**	(84,994)	617	**(255,464)**	(248,609)	(6,855)
Transportation	**(23,078)**	(23,060)	(18)	**(72,144)**	(62,383)	(9,761)
Blending and other	**(54,380)**	(49,750)	(4,630)	**(205,369)**	(184,951)	(20,418)
Operating netback [2] from continuing operations	**$ 349,555**	$ 226,456	$ 123,099	**$ 929,343**	$ 646,448	$ 282,895
General and administrative	**(12,445)**	(15,824)	3,379	**(51,224)**	(50,985)	(239)
Net cash interest income (expense)	**540**	(39,906)	40,446	**3,996**	(124,977)	128,973
Realized financial derivatives gain (loss)	**5,808**	(8,580)	14,388	**(107,627)**	(20,648)	(86,979)
Realized foreign exchange (loss) gain	**(500)**	(81)	(419)	**1,205**	116	1,089
Cash other expense	**(1,883)**	(702)	(1,181)	**(5,644)**	(5,801)	157
Current income tax expense	**(25)**	(1,076)	1,051	**(25)**	(8,061)	8,036
Cash share-based compensation	**(9,166)**	(8,440)	(726)	**(31,496)**	(9,716)	(21,780)
Adjusted funds flow [3] from continuing operations	**$ 331,884**	$ 151,847	$ 180,037	**$ 738,528**	$ 426,376	$ 312,152
Exploration and evaluation	**(50)**	(127)	77	**(1,525)**	(691)	(834)
Depletion and depreciation	**(131,138)**	(126,218)	(4,920)	**(383,773)**	(360,965)	(22,808)
Non-cash share-based compensation	**—**	—	—	**(4,857)**	—	(4,857)
Non-cash financing and interest	**(5,209)**	(7,156)	1,947	**(16,278)**	(19,521)	3,243
Unrealized financial derivatives gain (loss)	**5,072**	3,541	1,531	**(10,806)**	(15,347)	4,541
Unrealized foreign exchange gain (loss)	**132**	(36,840)	36,972	**(3,191)**	67,427	(70,618)
Gain on dispositions	**7,906**	1,591	6,315	**10,184**	1,028	9,156
Deferred income tax expense	**(48,329)**	(15,089)	(33,240)	**(79,105)**	(41,095)	(38,010)
Net income (loss) from continuing operations	**$ 160,268**	$ (28,451)	$ 188,719	**$ 249,177**	$ 57,212	$ 191,965
Net income from discontinued operations	**—**	60,419	(60,419)	**18,634**	195,896	(177,262)
Net income	**$ 160,268**	$ 31,968	$ 128,300	**$ 267,811**	$ 253,108	$ 14,703

(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[(1)] from continuing operations of $331.9 million for Q3/2026 and $738.5 million for YTD 2026 compared to $151.8 million for Q3/2025 and $426.4 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 and an increase in production, and lower cash interest expense due to the repayment of nearly all outstanding debt in Q4/2025. The increase in YTD 2026 operating netback was partially offset by higher realized losses on financial derivatives.

We reported net income from continuing operations of $160.3 million for Q3/2026 and $249.2 million for YTD 2026 compared to a net loss of $28.5 million for Q3/2025 and net income of $57.2 million for YTD 2025. The increase in net income for both periods of 2026 relative to 2025 is primarily due to an increase in adjusted funds flow.

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

CAPITAL EXPENDITURES

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

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2026**	2025	Change	**2026**	2025	Change
Drilling, completion and equipping	**$ 164,875**	$ 109,383	$ 55,492	**$ 385,001**	$ 398,810	$ (13,809)
Facilities and other	**21,554**	14,196	7,358	**68,682**	56,822	11,860
Exploration and development expenditures - continuing operations	**$ 186,429**	$ 123,579	$ 62,850	**$ 453,683**	$ 455,632	$ (1,949)
Exploration and development expenditures - discontinued operations	**—**	146,785	(146,785)	**—**	576,361	(576,361)
Total exploration and development expenditures	**$ 186,429**	$ 270,364	$ (83,935)	**$ 453,683**	$ 1,031,993	$ (578,310)
Property acquisitions - continuing operations	**$ 18,804**	$ 23,560	$ (4,756)	**$ 27,157**	$ 24,934	$ 2,223
Proceeds from dispositions - continuing operations	**$ (6,977)**	$ (8,254)	$ 1,277	**$ (6,775)**	$ (11,794)	$ 5,019
Property acquisitions - discontinued operations	**$ —**	$ 464	$ (464)	**$ —**	$ 1,540	$ (1,540)
Proceeds from dispositions - discontinued operations	**$ —**	$ —	$ —	**$ (19,434)**	$ 549	$ (19,983)

Exploration and development expenditures for continuing operations were $186.4 million in Q3/2026 and $453.7 million for YTD 2026 compared to $123.6 million in Q3/2025 and $455.6 million in YTD 2025. Exploration and development expenditures were higher in Q3/2026 compared to Q3/2025 due to increased activity in our Duvernay development program. Exploration and development expenditures for continuing operations for YTD 2026 included costs associated with drilling 158 (131.1 net) wells along with 148 (125.5 net) wells that were brought on production compared to drilling 175 (164.8 net) wells along with 177 (169.7 net) wells brought on production during YTD 2025. Total YTD spend is relatively consistent between the periods, but the focus has shifted in 2026 to Duvernay properties. Exploration and development expenditures for YTD 2026 in Duvernay were $197 million, while Viking and heavy oil properties had spend of $61 million and $196 million, respectively, compared to YTD 2025 which had expenditures in Duvernay of $141 million, and spend related to Viking and heavy oil properties of $85 million and $230 million, respectively. We also invested $68.7 million on facilities and other expenditures during YTD 2026.

Exploration and development expenditures of $453.7 million for YTD 2026 were consistent with expectations and our revised annual guidance for 2026 of approximately $665 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 September 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 September 30, 2026 we had net cash[(1)] of $522.4 million compared to $765.8 million at December 31, 2025. The decrease in net cash from December 31, 2025 primarily reflects shareholder returns of $507.5 million during YTD 2026, which includes share buybacks and quarterly dividends, partially offset by $268.3 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 September 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 September 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 September 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 financial covenants applicable to the Credit Facilities and calculated in accordance with the credit facility agreement are Senior Secured Debt to Bank EBITDA, Interest coverage, and Total Debt to Bank EBITDA. Senior Secured Debt to Bank EBITDA measures senior secured leverage based on the principal amount of the Credit Facilities and other secured obligations relative to Bank EBITDA, which is calculated on a twelve-month trailing basis and reflects net income or loss adjusted for various items specified in the credit facility agreement and has a maximum ratio of 3.5:1. Interest Coverage measures the Company's ability to cover financing and interest expense based on Bank EBITDA relative to financing and interest expense and has a minimum ratio of 3.5:1. Total Debt to Bank EBITDA measures overall leverage based on the Company's obligations, liabilities and indebtedness, excluding certain specified liabilities, relative to Bank EBITDA and has a maximum ratio of 4.0:1. Baytex is in compliance with all covenants contained in the credit facility agreement.

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 September 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 nine months ended September 30, 2026, we issued 0.1 million common shares pursuant to our share-based compensation program. As at September 30, 2026, we had 684.8 million common shares issued and outstanding and no preferred shares issued and outstanding. As at November 5, 2026, there were 675.2 million common shares issued and outstanding and no preferred shares issued and outstanding.

During the nine months ended September 30, 2026, we repurchased 80.9 million common shares under our normal course issuer bid ("NCIB") at an average price of $5.68 per share for total consideration of $459.2 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 nine months ended September 30, 2026, we recorded a $9.1 million charge to shareholders' capital related to the federal tax on equity repurchases (December 31, 2025 - $0.5 million).

On January 2, April 1, July 2, and October 1, 2026, we paid quarterly cash dividends of $0.0225 per share to shareholders of record. On November 5, 2026, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on January 4, 2027 to shareholders of record on December 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 September 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	**$ 91,011**	$ —	$ —	$ —	$ 91,011
Interest on long-term notes	**36,649**	6,712	13,424	13,424	3,089
Lease obligations - principal	**94,327**	15,723	23,473	16,912	38,219
Processing agreements	**4,252**	460	543	521	2,728
Transportation agreements	**60,766**	36,516	18,766	3,276	2,208
Total	**$ 287,005**	$ 59,411	$ 56,206	$ 34,133	$ 137,255

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 September 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)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Petroleum and natural gas sales	**605,859**	639,943	452,954	759,815	927,648	886,579	999,130	1,017,017
Net income (loss) - continuing operations [1]	**160,268**	168,588	(79,679)	(334,057)	(28,451)	103,018	(17,355)	(124,903)
Per common share - basic	**0.23**	0.23	(0.11)	(0.43)	(0.04)	0.13	(0.02)	(0.16)
Per common share - diluted	**0.23**	0.23	(0.11)	(0.43)	(0.04)	0.13	(0.02)	(0.16)
Net income (loss)	**160,268**	174,869	(67,326)	(856,887)	31,968	151,549	69,591	(38,477)
Per common share - basic	**0.23**	0.24	(0.09)	(1.12)	0.04	0.20	0.09	(0.05)
Per common share - diluted	**0.23**	0.24	(0.09)	(1.12)	0.04	0.20	0.09	(0.05)
Adjusted funds flow [2]	**331,884**	254,433	151,125	261,531	422,232	366,919	463,870	461,886
Per common share - basic	**0.48**	0.35	0.20	0.34	0.55	0.48	0.60	0.59
Per common share - diluted	**0.47**	0.35	0.20	0.34	0.55	0.48	0.60	0.59
Free cash flow [3]	**138,506**	128,045	1,705	76,486	142,688	3,188	52,529	254,838
Per common share - basic	**0.20**	0.18	—	0.10	0.19	—	0.07	0.33
Per common share - diluted	**0.20**	0.18	—	0.10	0.18	—	0.07	0.33
Cash flows from operating activities	**283,034**	230,852	122,203	227,657	472,676	354,312	431,317	468,865
Per common share - basic	**0.41**	0.32	0.16	0.30	0.62	0.46	0.56	0.60
Per common share - diluted	**0.40**	0.32	0.16	0.30	0.61	0.46	0.56	0.60
Dividends declared	**15,578**	16,144	16,606	17,268	17,326	17,304	17,289	17,598
Per common share	**0.0225**	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225
Exploration and development	**186,429**	122,242	145,012	174,078	270,364	356,532	405,097	198,177
Canada	**186,429**	122,242	145,012	92,720	123,579	147,734	184,319	108,971
U.S. [4]	**—**	—	—	81,358	146,785	208,798	220,778	89,206
Property acquisitions	**18,804**	226	8,127	5,544	24,024	1,193	1,257	12,621
Proceeds from dispositions	**(6,977)**	(6,119)	(13,113)	(3,012,058)	(8,254)	(725)	(2,266)	(42,339)
Net (cash) debt [2]	**(522,367)**	(566,286)	(591,151)	(765,785)	2,244,358	2,293,940	2,390,250	2,417,172
Total assets	**3,206,395**	3,169,943	3,252,692	3,345,414	7,601,389	7,552,013	7,824,576	7,759,745
Common shares outstanding	**684,800**	708,888	730,561	765,568	768,317	768,317	770,039	773,590
Daily production								
Total production (boe/d)	**71,606**	71,243	69,478	137,087	150,950	148,095	144,194	152,894
Canada (boe/d)	**71,606**	71,243	69,478	67,295	68,185	64,167	62,380	65,332
U.S. (boe/d) [4]	**—**	—	—	69,792	82,765	83,928	81,814	87,562
Benchmark prices								
WTI oil (US$/bbl)	**85.79**	92.79	71.93	59.14	64.93	63.74	71.42	70.27
WCS heavy oil ($/bbl)	**100.59**	108.16	79.28	66.88	75.14	74.10	84.33	80.77
Edmonton par oil ($/bbl)	**119.21**	132.26	93.50	76.49	86.20	84.15	95.27	94.98
AECO 7A natural gas ($/mcf)	**1.54**	1.51	2.49	2.34	1.00	2.07	2.02	1.46
CAD/USD avg exchange rate	**1.3988**	1.3836	1.3716	1.3949	1.3774	1.3840	1.4350	1.3992
Total sales, net of blending and other expense ($/boe) [3]	**83.71**	87.13	60.30	56.28	63.22	61.16	71.38	66.60
Royalties ($/boe) [5]	**(14.34)**	(13.94)	(8.25)	(11.54)	(13.05)	(13.16)	(16.02)	(14.69)
Operating expense ($/boe) [5]	**(12.81)**	(13.86)	(12.99)	(12.51)	(11.54)	(11.95)	(11.38)	(10.36)
Transportation expense ($/boe) [5]	**(3.50)**	(4.00)	(3.70)	(2.43)	(2.54)	(2.44)	(2.35)	(2.35)
Operating netback ($/boe) [3]	**53.06**	55.33	35.36	29.80	36.09	33.61	41.63	39.20
Financial derivatives (loss) gain ($/boe) [5]	**0.88**	(12.98)	(4.68)	0.08	(0.62)	(0.88)	(0.01)	(0.15)
Operating netback after financial derivatives ($/boe) [3]	**53.94**	42.35	30.68	29.88	35.47	32.73	41.62	39.05

(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 71,606 boe/d in Q3/2026 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 71,606 boe/d from 65,332 boe/d in Q4/2024 despite the disposition of certain thermal assets in Q4/2024.

Benchmark prices for crude oil declined from Q4/2024 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 Q3/2026 due to supply disruptions related to the conflict in Iran and resulted in realized pricing of $83.71/boe for Q3/2026 and operating netback after financial derivatives of $53.94/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 $331.9 million and cash flows from operating activities of $283.0 million for Q3/2026 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 $522.4 million at Q3/2026 compared to a net debt position of $2.4 billion at Q4/2024. The change in net (cash) debt also reflects free cash flow(2) of $543.1 million generated in the period since Q4/2024, along with $605.5 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 September 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 nine months ended September 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.

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 does not alter the recognition and measurement of items included in the statements of income or loss and comprehensive income or loss; however, it does change how items are presented. The statements of income or loss and comprehensive income or loss will include three new categories: operating, investing and financing. Items such as interest expense will be included in the financing section and items such as interest income on cash and cash equivalents will be included in the investing section. IFRS 18 establishes increased disclosure in the financial statements around management-defined performance measures, such as operating netback. 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.

In addition, consequential amendments have been made to IAS 7 *Statement of Cash Flows*, which include changing the starting point for determining cash flows from operations under the indirect method, from 'net income or loss' to a new subtotal referred to as 'operating income or loss' and removing the optionality around classification of cash flows from interest.

The Company is completing the evaluation of the impact that this standard will have on the consolidated financial statements.

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 September 30		Nine Months Ended September 30	
($ thousands)	**2026**	2025	**2026**	2025
Petroleum and natural gas sales	**$ 605,859**	$ 437,905	**$ 1,698,756**	$ 1,303,092
Light oil and condensate [(1)]	**(162,266)**	(99,188)	**(398,126)**	(282,532)
NGL [(1)]	**(10,690)**	(7,250)	**(30,210)**	(21,371)
Natural gas [(1)]	**(6,228)**	(2,462)	**(21,576)**	(17,219)
Heavy oil	**$ 426,675**	$ 329,005	**$ 1,248,844**	$ 981,970
Blending and other expense [(2)]	**(54,380)**	(49,750)	**(205,369)**	(184,951)
Heavy oil, net of blending and other expense	**$ 372,295**	$ 279,255	**$ 1,043,475**	$ 797,019

(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 nine months ended September 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 September 30		Nine Months Ended September 30	
($ thousands)	**2026**	2025	**2026**	2025
Petroleum and natural gas sales	**$ 605,859**	$ 437,905	**$ 1,698,756**	$ 1,303,092
Blending and other expense	**(54,380)**	(49,750)	**(205,369)**	(184,951)
Total sales, net of blending and other expense	**551,479**	388,155	**1,493,387**	1,118,141
Royalties	**(94,469)**	(53,645)	**(236,436)**	(160,701)
Operating expense	**(84,377)**	(84,994)	**(255,464)**	(248,609)
Transportation expense	**(23,078)**	(23,060)	**(72,144)**	(62,383)
Operating netback - continuing operations	**$ 349,555**	$ 226,456	**$ 929,343**	$ 646,448
Realized financial derivatives gain (loss) [(1)]	**5,808**	(8,580)	**(107,627)**	(20,648)
Operating netback after realized financial derivatives - continuing operations	**$ 355,363**	$ 217,876	**$ 821,716**	$ 625,800

(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 nine months ended September 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 September 30		Nine Months Ended September 30	
($ thousands)	**2026**	2025	**2026**	2025
Cash flows from operating activities	**$ 283,034**	$ 472,676	**$ 636,089**	$ 1,258,305
Change in non-cash working capital	**44,330**	(55,961)	**92,281**	(17,885)
Additions to exploration and evaluation assets	**(1,107)**	—	**(2,844)**	(930)
Additions to oil and gas properties	**(185,322)**	(270,364)	**(450,839)**	(1,031,063)
Payments on lease obligations	**(2,429)**	(3,663)	**(6,431)**	(10,022)
Free cash flow	**$ 138,506**	$ 142,688	**$ 268,256**	$ 198,405

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)	**September 30, 2026**	December 31, 2025
Credit facilities	**$ —**	$ 1,138
Unamortized debt issuance costs - Credit facilities [(1)]	**—**	262
Long-term notes	**89,201**	93,834
Unamortized debt issuance costs - Long-term notes [(1)]	**1,810**	2,113
Trade payables	**289,861**	236,373
Share-based compensation liability	**37,907**	34,802
Dividends payable	**15,578**	17,268
Cash	**(652,602)**	(953,113)
Trade receivables	**(244,000)**	(135,230)
Prepaids and other assets	**(58,498)**	(63,232)
Inventory	**(1,624)**	—
Net cash	**$ (522,367)**	$ (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 nine months ended September 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 September 30		Nine Months Ended September 30	
($ thousands)	**2026**	2025	**2026**	2025
Cash flow from operating activities	**$ 283,034**	$ 472,676	**$ 636,089**	$ 1,258,305
Change in non-cash working capital	**44,330**	(55,961)	**92,281**	(17,885)
Asset retirement obligations settled	**4,520**	5,517	**9,072**	12,601
Adjusted funds flow	**$ 331,884**	$ 422,232	**$ 737,442**	$ 1,253,021

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 nine months ended September 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 September 30, 2026	December 31, 2025
ASSETS			
Current assets			
Cash	18	**$ 652,602**	$ 953,113
Trade receivables	14, 18	**244,000**	135,230
Prepaids and other assets		**35,643**	35,008
Inventory		**1,624**	—
Financial derivatives	18	**16,933**	28,898
Assets held for sale	3	**—**	38,117
		950,802	1,190,366
Non-current assets			
Exploration and evaluation assets	4	**142,986**	133,585
Oil and gas properties	5	**2,027,713**	1,918,435
Other plant and equipment		**6,844**	7,648
Lease assets	7	**54,650**	20,812
Prepaids and other assets	15	**22,855**	28,224
Deferred income tax asset	15	**545**	46,344
		$ 3,206,395	$ 3,345,414
LIABILITIES			
Current liabilities			
Trade payables	18	**$ 289,861**	$ 236,373
Share-based compensation liability	12	**29,425**	26,108
Dividends payable	11, 18	**15,578**	17,268
Financial derivatives	18	**1,247**	2,406
Liabilities related to assets held for sale	3	**—**	23,710
Lease obligations	7	**10,438**	7,175
Asset retirement obligations	10	**17,440**	17,138
		363,989	330,178
Non-current liabilities			
Share-based compensation liability	12	**8,482**	8,694
Credit facilities	8, 18	**—**	1,138
Long-term notes	9, 18	**89,201**	93,834
Lease obligations	7	**48,662**	15,844
Asset retirement obligations	10	**516,761**	506,677
Deferred income tax liability	15	**33,287**	—
		1,060,382	956,365
SHAREHOLDERS' EQUITY			
Shareholders' capital	11	**5,417,909**	6,072,562
Contributed surplus		**589,610**	397,681
Accumulated other comprehensive income		**13,561**	13,356
Deficit		**(3,875,067)**	(4,094,550)
		2,146,013	2,389,049
		$ 3,206,395	$ 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
(thousands of Canadian dollars, except per common share amounts and weighted average common shares) (unaudited)

		Three Months Ended September 30		Nine Months Ended September 30	
	Notes	**2026**	2025 Revised [1]	**2026**	2025 Revised [1]
Revenue, net of royalties					
Petroleum and natural gas sales	14	**$ 605,859**	$ 437,905	**$ 1,698,756**	$ 1,303,092
Royalties		**(94,469)**	(53,645)	**(236,436)**	(160,701)
		511,390	384,260	**1,462,320**	1,142,391
Expenses					
Operating		**84,377**	84,994	**255,464**	248,609
Transportation		**23,078**	23,060	**72,144**	62,383
Blending and other		**54,380**	49,750	**205,369**	184,951
General and administrative		**12,445**	15,824	**51,224**	50,985
Exploration and evaluation	4	**50**	127	**1,525**	691
Depletion and depreciation		**131,138**	126,218	**383,773**	360,965
Share-based compensation	12	**9,166**	8,440	**36,353**	9,716
Net financing and interest expense	16	**4,669**	47,062	**12,282**	144,498
Financial derivatives (gain) loss	18	**(10,880)**	5,039	**118,433**	35,995
Foreign exchange loss (gain)	17	**368**	36,921	**1,986**	(67,543)
Gain on dispositions		**(7,906)**	(1,591)	**(10,184)**	(1,028)
Other expense		**1,883**	702	**5,644**	5,801
		302,768	396,546	**1,134,013**	1,036,023
Net income (loss) before income taxes from continuing operations		**208,622**	(12,286)	**328,307**	106,368
Income taxes	15				
Current income tax expense		**25**	1,076	**25**	8,061
Deferred income tax expense		**48,329**	15,089	**79,105**	41,095
		48,354	16,165	**79,130**	49,156
Net income (loss) from continuing operations		**$ 160,268**	$ (28,451)	**$ 249,177**	$ 57,212
Net income from discontinued operations	6	**$ —**	$ 60,419	**$ 18,634**	$ 195,896
Net income		**$ 160,268**	$ 31,968	**$ 267,811**	$ 253,108
Other comprehensive (loss) income					
Foreign currency translation adjustment		**(10)**	90,523	**205**	(165,343)
Comprehensive income		**$ 160,258**	$ 122,491	**$ 268,016**	$ 87,765
Net income (loss) per common share					
Continuing operations - basic		**$ 0.23**	$ (0.04)	**$ 0.34**	$ 0.07
Discontinued operations - basic		**$ —**	$ 0.08	**$ 0.03**	$ 0.26
Net income per share - basic		**$ 0.23**	$ 0.04	**$ 0.37**	$ 0.33
Continuing operations - diluted		**$ 0.23**	$ (0.04)	**$ 0.34**	$ 0.07
Discontinued operations - diluted		**$ —**	$ 0.08	**$ 0.03**	$ 0.26
Net income per share - diluted		**$ 0.23**	$ 0.04	**$ 0.37**	$ 0.33
Weighted average common shares (000s)	13				
Basic		**695,878**	768,317	**721,223**	769,481
Diluted		**700,731**	773,165	**725,800**	773,680

(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		—	—	—	(51,919)	**(51,919)**
Comprehensive (loss) income		—	—	(165,343)	253,108	**87,765**
Balance at September 30, 2025		$ 6,094,686	$ 387,818	$ 927,918	$ (3,220,395)	**$ 4,190,027**
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	(655,341)	187,072	—	—	**(468,269)**
Dividends declared	11	—	—	—	(48,328)	**(48,328)**
Comprehensive income		—	—	205	267,811	**268,016**
Balance at September 30, 2026		$ 5,417,909	$ 589,610	$ 13,561	$ (3,875,067)	**$ 2,146,013**

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)

	Notes	Three Months Ended September 30		Nine Months Ended September 30	
		2026	2025	**2026**	2025
CASH PROVIDED BY (USED IN):					
Operating activities					
Net income		**$ 160,268**	$ 31,968	**$ 267,811**	$ 253,108
Adjustments for:					
Non-cash share-based compensation	12	**—**	—	**4,857**	—
Unrealized foreign exchange (gain) loss	17	**(132)**	36,840	**3,191**	(67,427)
Exploration and evaluation	4	**50**	127	**1,525**	691
Depletion and depreciation		**131,138**	329,093	**383,773**	971,175
Non-cash financing and interest	16	**5,209**	8,563	**16,278**	23,860
Unrealized financial derivatives (gain) loss	18	**(5,072)**	(3,541)	**10,806**	15,347
Gain on dispositions		**(7,906)**	(1,591)	**(29,904)**	(1,028)
Deferred income tax expense	15	**48,329**	20,773	**79,105**	57,295
Asset retirement obligations settled	10	**(4,520)**	(5,517)	**(9,072)**	(12,601)
Change in non-cash working capital		**(44,330)**	55,961	**(92,281)**	17,885
Cash flows from operating activities		**283,034**	472,676	**636,089**	1,258,305
Financing activities					
Decrease in credit facilities	8	**—**	(155,729)	**(1,400)**	(153,582)
Debt issuance costs		**—**	—	**—**	(2,714)
Payments on lease obligations	7	**(2,429)**	(3,663)	**(6,431)**	(10,022)
Redemption of long-term notes	9	**—**	—	**(8,270)**	(53,681)
Repurchase of common shares	11	**(151,951)**	—	**(468,269)**	(17,159)
Dividends declared	11	**(15,578)**	(17,326)	**(48,328)**	(51,919)
Change in non-cash working capital		**2,977**	—	**8,234**	(2,803)
Cash flows used in financing activities		**(166,981)**	(176,718)	**(524,464)**	(291,880)
Investing activities					
Additions to exploration and evaluation assets	4	**(1,107)**	—	**(2,844)**	(930)
Additions to oil and gas properties	5	**(185,322)**	(270,364)	**(450,839)**	(1,031,063)
Additions to other plant and equipment		**(243)**	(611)	**(909)**	(1,405)
Additions to assets held for sale	3	**—**	(35,655)	**—**	(35,655)
Consideration related to assets held for sale	3	**—**	7,925	**14,407**	7,925
Property acquisitions		**(18,804)**	(24,024)	**(27,157)**	(26,474)
Proceeds from dispositions		**6,977**	8,254	**26,209**	11,245
Change in non-cash working capital		**14,711**	21,778	**27,194**	103,739
Cash flows used in investing activities		**(183,788)**	(292,697)	**(413,939)**	(972,618)
Change in cash		**(67,735)**	3,261	**(302,314)**	(6,193)
Opening balance prior to restatement for IFRS 9 amendments		**720,337**	7,156	**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		**720,337**	7,156	**954,916**	16,610
Cash, end of period		**$ 652,602**	$ 10,417	**$ 652,602**	$ 10,417
Supplementary information					
Interest paid		**$ 3,385**	$ 36,088	**$ 8,680**	$ 126,720
Interest received		**$ 4,513**	$ —	**$ 14,842**	$ —
Income taxes paid		**$ —**	$ 2,453	**$ 29,770**	$ 22,094
Income taxes refunded		**$ —**	$ —	**$ 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 November 5, 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 does not alter the recognition and measurement of items included in the statements of income or loss and comprehensive income or loss; however, it does change how items are presented. The statements of income or loss and comprehensive income or loss will include three new categories: operating, investing and financing. Items such as interest expense will be included in the financing section and items such as interest income on cash and cash equivalents will be included in the investing section. IFRS 18 establishes increased disclosure in the financial statements around management-defined performance measures, such as operating netback. 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.

In addition, consequential amendments have been made to IAS 7 *Statement of Cash Flows*, which include changing the starting point for determining cash flows from operations under the indirect method, from 'net income or loss' to a new subtotal referred to as 'operating income or loss' and removing the optionality around classification of cash flows from interest.

The Company is completing the evaluation of 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

	September 30, 2026	December 31, 2025
Balance, beginning of period	**$ 133,585**	$ 124,355
Additions to exploration and evaluation assets	**2,844**	930
Property acquisitions	**12,064**	34,148
Divestitures	**(2,067)**	(8,577)
Exploration and evaluation expense	**(1,525)**	(5,534)
Transfer to oil and gas properties (note 5)	**(1,915)**	(11,737)
Balance, end of period	**$ 142,986**	$ 133,585

At September 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	450,839	—	450,839
Property acquisitions	16,268	—	16,268
Transfers from exploration and evaluation assets (note 4)	1,915	—	1,915
Change in asset retirement obligations (note 10)	10,824	—	10,824
Divestitures	(10,309)	7,905	(2,404)
Depletion	—	(368,164)	(368,164)
Balance, September 30, 2026	**$ 7,832,119**	**$ (5,804,406)**	**$ 2,027,713**

At September 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 December 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 nine months ended September 30, 2026, the Company recorded post-closing adjustments of $18.6 million. There were no post-closing adjustments in the three months ended September 30, 2026.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2026	2025	**2026**	2025
Revenue, net of royalties				
Petroleum and natural gas sales	**$ —**	$ 489,743	**$ —**	$ 1,510,265
Royalties	**—**	(127,585)	**—**	(405,856)
	—	362,158	**—**	1,104,409
Expenses				
Operating	**—**	75,290	**—**	220,398
Transportation	**—**	12,235	**—**	36,331
General and administrative	**—**	4,912	**—**	17,577
Depletion and depreciation	**—**	202,875	**—**	610,210
Share-based compensation	**—**	2,297	**—**	3,339
Financing and interest	**—**	5,374	**—**	14,897
Other income	**—**	(119)	**—**	(3,344)
	—	302,864	**—**	899,408
Net income before income taxes - operations	**—**	59,294	**—**	205,001
Income taxes - operations				
Current income tax recovery - operations	**—**	(6,809)	**—**	(7,095)
Deferred income tax expense - operations	**—**	5,684	**—**	16,200
	—	(1,125)	**—**	9,105
Net income - operations	**$ —**	$ 60,419	**$ —**	$ 195,896
Gain on disposition after tax	**—**	—	**18,634**	—
Net income - discontinued operations	**$ —**	$ 60,419	**$ 18,634**	$ 195,896

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2026	2025	**2026**	2025
Cash provided by (used in) discontinued operations:				
Operating activities	**$ —**	$ 293,739	**$ —**	$ 838,591
Financing activities	**—**	(108,554)	**—**	(69,164)
Investing activities	**—**	(123,946)	**12,403**	(501,655)
Increase in cash from discontinued operations	**$ —**	$ 61,239	**$ 12,403**	$ 267,772

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	—	40,561	599	41,160
Modifications	27	1,365	(40)	1,352
Depreciation	(997)	(7,107)	(570)	(8,674)
Balance, September 30, 2026	**$ 4,875**	**$ 48,836**	**$ 939**	**$ 54,650**

Lease Obligations

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

	September 30, 2026	December 31, 2025
Less than 1 year	**$ 15,723**	$ 8,487
1 - 3 years	**23,473**	10,690
3 - 5 years	**16,912**	7,097
After 5 years	**38,219**	—
Total lease payments	**94,327**	26,274
Amounts representing interest over the term of the lease	**(35,227)**	(3,255)
Present value of net lease payments	**59,100**	23,019
Less current portion of lease obligations	**10,438**	7,175
Non-current portion of lease obligations	**$ 48,662**	$ 15,844

For the three and nine months ended September 30, 2026 the Company recorded interest expense related to its lease obligations of $1.4 million and $4.0 million respectively ($0.3 million and $1.0 million for the three and nine months ended September 30, 2025). For the three and nine months ended September 30, 2026 the Company recorded lease payments, excluding interest, of $2.4 million and $6.4 million respectively ($3.7 million and $10.0 million for the three and nine months ended September 30, 2025).

8. CREDIT FACILITIES

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

At September 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 financial covenants applicable to the Credit Facilities and calculated in accordance with the credit facility agreement are Senior Secured Debt to Bank EBITDA, Interest coverage, and Total Debt to Bank EBITDA. Senior Secured Debt to Bank EBITDA measures senior secured leverage based on the principal amount of the Credit Facilities and other secured obligations relative to Bank EBITDA, which is calculated on a twelve-month trailing basis and reflects net income or loss adjusted for various items specified in the credit facility agreement and has a maximum ratio of 3.5:1. Interest Coverage measures the Company's ability to cover financing and interest expense based on Bank EBITDA relative to financing and interest expense and has a minimum ratio of 3.5:1. Total Debt to Bank EBITDA measures overall leverage based on the Company's obligations, liabilities and indebtedness, excluding certain specified liabilities, relative to Bank EBITDA and has a maximum ratio of 4.0:1. Baytex is in compliance with all covenants contained in the credit facility agreement.

At September 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

	September 30, 2026	December 31, 2025
7.375% notes due March 15, 2032 [(1)]	**$ 91,011**	$ 95,947
Unamortized debt issuance costs	**(1,810)**	(2,113)
Total long-term notes - net of unamortized debt issuance costs	**$ 89,201**	$ 93,834

(1) The U.S. dollar denominated principal outstanding of the 7.375% notes was US$64.1 million as at September 30, 2026 (December 31, 2025 - US$70.0 million). The decrease in the principal amount outstanding from December 31, 2025 to September 30, 2026 is the result of the repurchase and cancellation of US$5.8 million ($8.0 million). This was partially offset by changes in the reported amount of U.S. denominated debt of $3.0 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 nine months ended September 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

	September 30, 2026	December 31, 2025
Balance, beginning of period	**$ 523,815**	$ 640,951
Liabilities incurred [(1)]	**10,684**	20,794
Liabilities settled	**(9,072)**	(20,318)
Liabilities acquired from property acquisitions	**1,175**	—
Liabilities divested	**(7,880)**	(104,223)
Accretion (note 16)	**15,339**	23,012
Change in estimate [(1)]	**6,216**	(7,442)
Changes in discount and inflation rates [(1)(2)]	**(6,076)**	(24,663)
Foreign currency translation	**—**	(4,296)
Balance, end of period	**$ 534,201**	$ 523,815
Less current portion of asset retirement obligations	**17,440**	17,138
Non-current portion of asset retirement obligations	**$ 516,761**	$ 506,677

(1) The total of these items reflects the total change in asset retirement obligations of $10.8 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 September 30, 2026 were 4.3% and 2.3% 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 September 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	(80,893)	(655,341)
Balance, September 30, 2026	**684,800**	**$ 5,417,909**

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 nine months ended September 30, 2026, Baytex recorded $468.3 million related to common share repurchases, which includes $459.2 million of consideration paid for the repurchase and cancellation of common shares as well as $9.1 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 nine months ended September 30, 2026, Baytex repurchased and cancelled 80.9 million common shares (8.1 million for the year ended December 31, 2025) at an average price of $5.68 per share ($3.55 for the year ended December 31, 2025) for total consideration of $459.2 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 nine months ended September 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
September 15, 2026	October 1, 2026	0.0225	15,578
Total dividends declared			**$ 48,328**

On November 5, 2026, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on January 4, 2027 to shareholders of record on December 15, 2026.

12. SHARE-BASED COMPENSATION PLAN

For the three and nine months ended September 30, 2026 the Company recorded share-based compensation expense for continuing operations of $9.2 million and $36.4 million respectively which includes $4.9 million of non-cash compensation expense recorded in the nine months ended September 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 nine months ended September 30, 2025, the Company recorded share-based compensation expense of $8.4 million and $9.7 million respectively for continuing operations and $2.3 million and $3.3 million for discontinued operations respectively which was related to cash-settled awards.

The Company's closing share price on the TSX on September 30, 2026 was $6.43 (December 31, 2025 - $4.44 and September 30, 2025 - $3.26).

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 nine months ended September 30, 2026 was $5.57 per performance award ($2.92 for the nine months ended September 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 nine months ended September 30, 2026 was $5.53 per incentive award ($2.91 for the nine months ended September 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 nine months ended September 30, 2026 was $6.07 per DSU award ($2.73 for the nine months ended September 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	—	1,365	1,816	131	3,312
Added by performance factor	—	269	—	—	269
Vested	(23)	(2,414)	(2,356)	(371)	(5,164)
Forfeited	—	(79)	(401)	—	(480)
Total, September 30, 2026	**—**	**3,981**	**4,511**	**1,706**	**10,198**

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 September 30		Nine Months Ended September 30	
(000s)	**2026**	2025	**2026**	2025
Weighted average common shares - basic	**695,878**	768,317	**721,223**	769,481
Dilutive effect of share-based compensation	**4,853**	4,848	**4,577**	4,199
Weighted average common shares - diluted	**700,731**	773,165	**725,800**	773,680

For the three and nine months ended September 30, 2026 and September 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 September 30		Nine Months Ended September 30	
	2026	2025 [(1)]	**2026**	2025 [(1)]
Light oil and condensate	**$ 162,266**	$ 99,188	**$ 398,126**	$ 282,532
Heavy oil	**426,675**	329,005	**1,248,844**	981,970
NGL	**10,690**	7,250	**30,210**	21,371
Natural gas	**6,228**	2,462	**21,576**	17,219
Total petroleum and natural gas sales - continuing operations	**$ 605,859**	$ 437,905	**$ 1,698,756**	$ 1,303,092
Total petroleum and natural gas sales - discontinued operations	**$ —**	$ 489,743	**$ —**	$ 1,510,265

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

Included in trade receivables at September 30, 2026 is $217.0 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 September 30		Nine Months Ended September 30	
	2026	2025 [1]	**2026**	2025 [1]
Interest on Credit Facilities	**$ 827**	$ 2,951	**$ 2,556**	$ 9,790
Interest on long-term notes	**1,676**	36,718	**5,031**	114,680
Interest on lease obligations	**1,423**	323	**3,961**	985
Interest income	**(4,466)**	(86)	**(15,544)**	(478)
Net cash interest (income) expense	**$ (540)**	$ 39,906	**$ (3,996)**	$ 124,977
Amortization of debt issue costs	**63**	2,217	**642**	8,121
Accretion on asset retirement obligations (note 10)	**5,146**	4,939	**15,339**	14,155
Early redemption expense (gain)	**—**	—	**297**	(2,755)
Net financing and interest expense - continuing operations	**$ 4,669**	$ 47,062	**$ 12,282**	$ 144,498
Net financing and interest expense - discontinued operations	**$ —**	$ 5,374	**$ —**	$ 14,897

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

17. FOREIGN EXCHANGE

	Three Months Ended September 30		Nine Months Ended September 30	
	2026	2025	**2026**	2025
Unrealized foreign exchange (gain) loss	**$ (132)**	$ 36,840	**$ 3,191**	$ (67,427)
Realized foreign exchange loss (gain)	**500**	81	**(1,205)**	(116)
Foreign exchange loss (gain) - continuing operations	**$ 368**	$ 36,921	**$ 1,986**	$ (67,543)

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:

	September 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	**$ 16,933**	**$ 16,933**	$ 28,898	$ 28,898	Level 2
Total	**$ 16,933**	**$ 16,933**	$ 28,898	$ 28,898	
Amortized cost					
Cash	**$ 652,602**	**$ 652,602**	$ 953,113	$ 953,113	—
Trade receivables	**244,000**	**244,000**	135,230	135,230	—
Total	**$ 896,602**	**$ 896,602**	$ 1,088,343	$ 1,088,343	
Financial Liabilities					
Fair value through profit and loss					
Financial derivatives	**$ (1,247)**	**$ (1,247)**	$ (2,406)	$ (2,406)	Level 2
Total	**$ (1,247)**	**$ (1,247)**	$ (2,406)	$ (2,406)	
Amortized cost					
Trade payables	**$ (289,861)**	**$ (289,861)**	$ (236,373)	$ (236,373)	—
Dividends payable	**(15,578)**	**(15,578)**	(17,268)	(17,268)	—
Credit Facilities [(1)]	**—**	**—**	(1,138)	(1,400)	—
Long-term notes	**(89,201)**	**(93,818)**	(93,834)	(99,808)	Level 1
Total	**$ (394,640)**	**$ (399,257)**	$ (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 nine months ended September 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	
	September 30, 2026	December 31, 2025	**September 30, 2026**	December 31, 2025
U.S. dollar denominated	**US$17,264**	US$22,204	**US$68,409**	US$84,500

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following commodity financial derivative contracts outstanding as at November 5, 2026.

	Remaining Period	Volume	Price/Unit [(1)]	Index
Oil				
Basis differential	Oct 2026 to Dec 2026	22,000 bbl/d	WTI less US$13.20/bbl	WCS
Basis differential	Oct 2026 to Dec 2026	1,000 bbl/d	WTI less US$4.25/bbl	MSW
Natural Gas				
Swap	Oct 2026 to Dec 2026	9,000 GJ/d	$1.99/GJ	AECO 5A
Swap	Jan 2027 to Dec 2027	12,500 GJ/d	$2.00/GJ	AECO 5A
Swap	Jan 2027 to Dec 2027	12,500 GJ/d	$2.01/GJ	AECO 7A
Basis differential	Oct 2026 to Dec 2026	2,500 mmbtu/d	NYMEX less US$1.66/mmbtu	NYMEX/AECO 7A
Collar	Oct 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 September 30		Nine Months Ended September 30	
	2026	2025	**2026**	2025
Realized financial derivatives (gain) loss	**$ (5,808)**	$ 8,580	**$ 107,627**	$ 20,648
Unrealized financial derivatives (gain) loss	**(5,072)**	(3,541)	**10,806**	15,347
Financial derivatives (gain) loss	**$ (10,880)**	$ 5,039	**$ 118,433**	$ 35,995

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 September 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.

	September 30, 2026	December 31, 2025
Credit Facilities	**$ —**	$ 1,138
Unamortized debt issuance costs - Credit Facilities (note 8)	**—**	262
Long-term notes	**89,201**	93,834
Unamortized debt issuance costs - Long-term notes (note 9)	**1,810**	2,113
Trade payables	**289,861**	236,373
Share-based compensation liability	**37,907**	34,802
Dividends payable	**15,578**	17,268
Cash	**(652,602)**	(953,113)
Trade receivables	**(244,000)**	(135,230)
Prepaids and other assets	**(58,498)**	(63,232)
Inventory	**(1,624)**	—
Net Cash	**$ (522,367)**	$ (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 September 30		Nine Months Ended September 30	
	2026	2025	**2026**	2025
Cash flows from operating activities	**$ 283,034**	$ 472,676	**$ 636,089**	$ 1,258,305
Change in non-cash working capital	**44,330**	(55,961)	**92,281**	(17,885)
Asset retirement obligations settled	**4,520**	5,517	**9,072**	12,601
Adjusted Funds Flow	**$ 331,884**	$ 422,232	**$ 737,442**	$ 1,253,021