BAYTEX DELIVERS SOLID SECOND QUARTER 2025 RESULTS WITH RECORD PEMBINA DUVERNAY WELL PERFORMANCE AND CONTINUED DEBT REDUCTION

CALGARY, ALBERTA (July 31, 2025) - Baytex Energy Corp. ("Baytex" or the "Company") (TSX:BTE) (NYSE:BTE) reports its operating and financial results for the three and six months ended June 30, 2025 (all amounts are in Canadian dollars unless otherwise noted).

"Baytex delivered solid operational and financial results in the second quarter, with top-performing wells in the Pembina Duvernay, setting the highest average 30-day peak oil rates in the West Shale Basin," said Eric T. Greager, President and Chief Executive Officer. "Combined with strong results across heavy oil operations and the Eagle Ford, including continued success with refracs, these results demonstrate the resource potential and value creation opportunities within our portfolio. We remain focused on disciplined capital allocation, prioritizing free cash flow and debt reduction while capitalizing on the most compelling opportunities from our high-quality assets."

Second Quarter 2025 Highlights

- Achieved record Pembina Duvernay well performance with the first pad (3 wells) delivering average peak 30-day initial rates of 1,865 boe/d per well (89% oil and NGL).
- Successfully completed two Lower Eagle Ford refracs, extending inventory duration and improving capital efficiencies.
- Delivered production of 148,095 boe/d (84% oil and NGL), which represents a 2% increase in production per basic share compared to Q2/2024.
- Increased heavy oil production 7% over Q1/2025, driven by strong Peavine, Peace River and Lloydminster performance.
- Reported cash flows from operating activities of $354 million ($0.46 per basic share).
- Generated net income of $152 million ($0.20 per basic share).
- Delivered adjusted funds flow(1) of $367 million ($0.48 per basic share).
- Repurchased and cancelled US$41 million principal amount of 8.5% long-term notes.
- Reduced net debt(1) by 4% ($96 million) and maintained balance sheet strength with a total debt(2) to Bank EBITDA(2) ratio of 1.1x.

2025 Outlook

In light of the current commodity price environment, we are targeting annual production of approximately 148,000 boe/d with full-year exploration and development expenditures of approximately $1.2 billion. Production is expected to average approximately 150,000 boe/d in the second half of 2025.

Based on forward strip pricing(3), we expect to generate approximately $400 million of free cash flow(4) in 2025, with the majority weighted to the second half of the year given our production and capital spending profile. We plan to allocate 100% of free cash flow to debt repayment after funding quarterly dividend payments, targeting net debt of approximately $2 billion by year-end.

We remain committed to disciplined capital allocation, prioritizing free cash flow and strengthening our balance sheet. We will continue to monitor market conditions and execute a prudent approach to shareholder returns, which has historically included a combination of share buybacks and quarterly dividend payments.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Ratio is calculated as total debt on June 30, 2025 divided by EBITDA for the twelve months ended June 30, 2025. Total debt and EBITDA are calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.
(3) 2025 full-year pricing assumptions: WTI - US$67.75/bbl; WCS differential - US$11.50/bbl; NYMEX Gas - US$3.60/MMbtu; Exchange Rate (CAD/USD) - 1.39.
(4) Specified financial measure that does not have any standardized meaning prescribed by International Financial Reporting Standards ("IFRS") and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.

	Three Months Ended			Six Months Ended	
	June 30, 2025	March 31, 2025	June 30, 2024	**June 30, 2025**	June 30, 2024
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 886,579**	$ 999,130	$ 1,133,123	**$ 1,885,709**	$ 2,117,315
Adjusted funds flow (1)	**366,919**	463,870	532,839	**830,789**	956,685
Per share – basic	**0.48**	0.60	0.65	**1.08**	1.17
Per share – diluted	**0.48**	0.60	0.65	**1.07**	1.16
Free cash flow (2)	**3,188**	52,529	180,673	**55,717**	180,585
Per share – basic	**—**	0.07	0.22	**0.07**	0.22
Per share – diluted	**—**	0.07	0.22	**0.07**	0.22
Cash flows from operating activities	**354,312**	431,317	505,584	**785,629**	889,357
Per share – basic	**0.46**	0.56	0.62	**1.02**	1.09
Per share – diluted	**0.46**	0.56	0.62	**1.02**	1.08
Net income	**151,549**	69,591	103,898	**221,140**	89,855
Per share – basic	**0.20**	0.09	0.13	**0.29**	0.11
Per share – diluted	**0.20**	0.09	0.13	**0.29**	0.11
Dividends declared	**17,304**	17,334	18,161	**34,593**	36,655
Per share	**0.0225**	0.0225	0.0225	**0.0450**	0.0450
Capital Expenditures					
Exploration and development expenditures	**$ 356,532**	$ 405,097	$ 339,573	**$ 761,629**	$ 752,124
Acquisitions and divestitures	**468**	(1,009)	654	**(541)**	36,032
Total oil and natural gas capital expenditures	**$ 357,000**	$ 404,088	$ 340,227	**$ 761,088**	$ 788,156
Net Debt					
Credit facilities	**$ 333,516**	$ 250,284	$ 625,976	**$ 333,516**	$ 625,976
Long-term notes	**1,817,707**	1,977,044	1,881,894	**1,817,707**	1,881,894
Total debt (3)	**2,151,223**	2,227,328	2,507,870	**2,151,223**	2,507,870
Working capital deficiency (2)	**142,717**	162,922	131,144	**142,717**	131,144
Net debt (1)	**$ 2,293,940**	$ 2,390,250	$ 2,639,014	**$ 2,293,940**	$ 2,639,014
Shares Outstanding - basic (thousands)					
Weighted average	**768,717**	771,443	814,151	**770,072**	817,931
End of period	**768,317**	770,039	804,977	**768,317**	804,977
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 63.74**	$ 71.42	$ 80.57	**$ 67.58**	$ 78.77
MEH oil (US$/bbl)	**65.56**	73.37	83.10	**69.47**	81.03
MEH oil differential to WTI (US$/bbl)	**1.82**	1.95	2.53	**1.89**	2.26
Edmonton par ($/bbl)	**84.15**	95.27	105.30	**89.71**	98.73
Edmonton par differential to WTI (US$/bbl)	**(2.94)**	(5.03)	(3.62)	**(3.93)**	(6.10)
WCS heavy oil ($/bbl)	**74.10**	84.33	91.72	**79.15**	84.68
WCS differential to WTI (US$/bbl)	**(10.20)**	(12.65)	(13.55)	**(11.43)**	(16.44)
Natural gas					
NYMEX (US$/MMbtu)	**$ 3.44**	$ 3.65	$ 1.89	**$ 3.55**	$ 2.07
AECO ($/Mcf)	**2.07**	2.02	1.44	**2.05**	1.74
CAD/USD average exchange rate	**1.3840**	1.4350	1.3684	**1.4095**	1.3586

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 amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.

	Three Months Ended			Six Months Ended	
	June 30, 2025	March 31, 2025	June 30, 2024	**June 30, 2025**	June 30, 2024
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**62,108**	62,335	67,031	**62,221**	66,534
Heavy oil (bbl/d)	**42,959**	40,192	43,703	**41,583**	42,131
NGL (bbl/d)	**19,948**	19,046	20,167	**19,499**	19,733
Total liquids (bbl/d)	**125,015**	121,573	130,901	**123,303**	128,398
Natural gas (Mcf/d)	**138,482**	135,731	139,764	**137,114**	144,059
Oil equivalent (boe/d @ 6:1) (1)	**148,095**	144,194	154,194	**146,156**	152,407
Adjusted Funds Flow (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 824,198**	$ 926,310	$ 1,065,438	**$ 1,750,508**	$ 1,985,422
Royalties	**(177,390)**	(207,937)	(240,440)	**(385,327)**	(449,611)
Operating expense	**(161,020)**	(147,703)	(167,705)	**(308,723)**	(341,140)
Transportation expense	**(32,907)**	(30,512)	(33,314)	**(63,419)**	(63,149)
Operating netback (2)	**$ 452,881**	$ 540,158	$ 623,979	**$ 993,039**	**$ 1,131,522**
General and administrative expense	**(22,220)**	(25,606)	(21,006)	**(47,826)**	(43,418)
Cash interest	**(44,875)**	(46,787)	(53,946)	**(91,662)**	(107,226)
Realized financial derivatives (loss) gain	**(11,874)**	(194)	(2,257)	**(12,068)**	3,231
Other (3)	**(6,993)**	(3,701)	(13,931)	**(10,694)**	(27,424)
Adjusted funds flow (4)	**$ 366,919**	$ 463,870	$ 532,839	**$ 830,789**	**$ 956,685**
Adjusted Funds Flow (per boe)					
Total sales, net of blending and other expense (2)	**$ 61.16**	$ 71.38	$ 75.93	**$ 66.17**	$ 71.58
Royalties (5)	**(13.16)**	(16.02)	(17.14)	**(14.57)**	(16.21)
Operating expense (5)	**(11.95)**	(11.38)	(11.95)	**(11.67)**	(12.30)
Transportation expense (5)	**(2.44)**	(2.35)	(2.37)	**(2.40)**	(2.28)
Operating netback (2)	**$ 33.61**	$ 41.63	$ 44.47	**$ 37.53**	**$ 40.79**
General and administrative expense (5)	**(1.65)**	(1.97)	(1.50)	**(1.81)**	(1.57)
Cash interest (5)	**(3.33)**	(3.61)	(3.84)	**(3.46)**	(3.87)
Realized financial derivatives (loss) gain (5)	**(0.88)**	(0.01)	(0.16)	**(0.46)**	0.12
Other (3)(5)	**(0.52)**	(0.30)	(1.00)	**(0.40)**	(0.98)
Adjusted funds flow	**$ 27.23**	$ 35.74	$ 37.97	**$ 31.40**	**$ 34.49**

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, other income or expense, current income tax expense and cash share-based compensation. Refer to the Q2/2025 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 interest, realized financial derivatives gain or loss, or other, divided by barrels of oil equivalent production volume for the applicable period.

Financial Results

During the second quarter, we delivered operating and financial results in line with our full-year plan. Adjusted funds flow(1) was $367 million ($0.48 per basic share) and net income was $152 million ($0.20 per basic share).

We generated free cash flow(2) of $3 million and returned $21 million to shareholders through share repurchases of $4 million (1.7 million shares at an average price of $2.36) and a quarterly dividend payment of $17 million.

Net debt(1) decreased 4% ($96 million) to $2.3 billion, driven by unrealized foreign exchange gains from a strengthening Canadian dollar on our U.S. dollar-denominated debt. During the quarter, we repurchased and cancelled US$41 million principal amount of the 8.5% long-term notes below par.

We maintain strong financial flexibility with US$1.1 billion in credit facilities that mature in June 2029 and are less than 25% drawn, positioning us well across various commodity price cycles.

Operations

Production averaged 148,095 boe/d (84% oil and NGL) in the second quarter, representing a 2% increase in production per basic share compared to Q2/2024. Consistent with our full-year plan, exploration and development expenditures for Q2/2025 totaled $357 million and we brought 74 (66.5 net) wells onstream.

Inventory Extension Through Successful Eagle Ford Refracs

Eagle Ford production averaged 83,928 boe/d (81% oil and NGL), up 3% from Q1/2025. We brought onstream 14.9 net wells while realizing an approximate 11% improvement in operated drilling and completion costs per completed lateral foot compared to 2024. We also completed two successful refracs that are delivering initial rates comparable to our broader development program with improved capital efficiencies and returns.

The two refracs (Moulton A5H and Renee Unit 2H) were brought onstream in April and May with average completed lateral lengths of 1,648 meters (5,406 feet) and generated average 30-day peak production rates of 963 boe/d per well (734 bbl/d of crude oil, 124 bbl/d of NGLs, 631 Mcf/d of natural gas).

The refrac program extends inventory duration – we have identified approximately 300 refrac opportunities across our acreage and anticipate an expanded program in 2026.

Record Pembina Duvernay Well Results Demonstrate Asset Potential

Production from our Canadian light oil business averaged 16,349 boe/d (81% oil and NGL), relatively unchanged from Q1/2025. The Pembina Duvernay represents our largest growth asset and accounts for 40% of Canadian light oil production, with the remaining 60% from Viking operations.

The first Pembina Duvernay pad (07-01, 3 wells) from our 2025 program was brought onstream in May with average lateral lengths of 3,800 meters (12,500 feet) and generated average 30-day peak production rates of 1,865 boe/d per well (1,239 bbl/d of crude oil, 422 bbl/d of NGLs, 1,224 Mcf/d of natural gas). The second pad (08-08, 3 wells) came onstream through early July with similar lateral lengths, and over the last 26 days has averaged 1,264 boe/d per well (709 bbl/d of crude oil, 352 bbl/d of NGLs, 1,220 Mcf/d of natural gas. The third pad (10-31, 3 wells) is expected onstream in September.

The first two pads have exceeded initial rate expectations with the first pad delivering the highest peak oil rates to-date in the West Shale Basin. These results demonstrate our continued advancement in drilling and completion performance and facility enhancements. Strong production performance, combined with an approximate 12% improvement in drilling and completion costs per completed lateral foot compared to 2024 has significantly improved well economics.

We have assembled 140 net sections of highly prospective lands and identified approximately 200 drilling locations. As we transition to full commercialization over the next two years, we plan to implement a one-rig drilling program with 18 to 20 wells per year. At this development pace, we expect production to increase to 20,000-25,000 boe/d by 2029-2030, up from 6,665 boe/d in the second quarter.

(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.

Organic Heavy Oil Growth

Heavy oil production averaged 44,895 boe/d (96% oil and NGL), up 7% from Q1/2025. Strong operating results reflect continued performance at Peavine, Peace River, and across the broader Mannville group in Lloydminster. During the quarter, we brought onstream 43 net wells: 15 Clearwater wells at Peavine, 4 wells at Peace River, and 24 wells at Lloydminster.

Our heavy oil operations deliver the strongest economic returns across the portfolio, supported by our extensive acreage position, capital-efficient development, and the continued strength in Western Canadian Select pricing.

Quarterly Dividend

The Board of Directors has declared a quarterly cash dividend of $0.0225 per share, payable October 1, 2025 to shareholders of record on September 15, 2025.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 30, 2025 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
9:00 a.m. MT (11:00 a.m. ET)

Baytex will host a conference call tomorrow, August 1, 2025, starting at 9:00am MT (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=mLhH9WQY 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: we are focused on disciplined capital allocation, prioritizing free cash flow, debt reduction and maximizing shareholder returns; for 2025: our guidance for exploration and development expenditures and production and the amount of free cash flow we expect to generate and its expected allocation; our targeted net debt at year-end 2025; the opportunity for refracs on our Eagle Ford acreage and the expected 2026 refrac program; and our Pembina Duvernay development plans. 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 in drilling new wells; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; operating costs; our ability to borrow under our credit agreements; 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 market oil and natural gas successfully; that we will have sufficient financial resources in the future to 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; risks associated with achieving our total debt target, production guidance, *exploration and development expenditures guidance; the amount of free cash flow we expect to generate; risk that the board of directors determines to allocate capital other than as set forth herein; 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; risks associated with a third-party operating our Eagle Ford properties; additional risks associated with our thermal heavy crude oil projects; our ability to compete with other organizations in the oil and gas industry; risk that we do not achieve our GHG emissions intensity reduction target; 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, 2024 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 2025 guidance for development expenditures; our expected 2025 free cash flow; and our intentions regarding the allocating our annual free cash flow; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Company and the resulting financial results will vary from the amounts set forth in this press release and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Company undertakes no obligation to update such financial outlook, whether as a result of new information, future events or otherwise. The financial outlook contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about the Company's potential future business operations. Readers are cautioned that the financial outlook contained in this press release is not conclusive and is subject to change.

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

Specified Financial Measures

In this press release, we refer to certain financial measures (such as total sales, net of blending and other expense, operating netback, free cash flow, and working capital 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 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

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. 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

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.

The following table reconciles total sales, net of blending and other expense and operating netback to petroleum and natural gas sales.

	Three Months Ended			Six Months Ended	
($ thousands)	**June 30, 2025**	March 31, 2025	June 30, 2024	**June 30, 2025**	June 30, 2024
Petroleum and natural gas sales	**$ 886,579**	$ 999,130	$ 1,133,123	**$ 1,885,709**	$ 2,117,315
Blending and other expense	**(62,381)**	(72,820)	(67,685)	**(135,201)**	(131,893)
Total sales, net of blending and other expense	**$ 824,198**	$ 926,310	$ 1,065,438	**$ 1,750,508**	$ 1,985,422
Royalties	**(177,390)**	(207,937)	(240,440)	**(385,327)**	(449,611)
Operating expense	**(161,020)**	(147,703)	(167,705)	**(308,723)**	(341,140)
Transportation expense	**(32,907)**	(30,512)	(33,314)	**(63,419)**	(63,149)
Operating netback	**$ 452,881**	$ 540,158	$ 623,979	**$ 993,039**	$ 1,131,522
Realized financial derivatives (loss) gain [1]	**(11,874)**	(194)	(2,257)	**(12,068)**	3,231
Operating netback after realized financial derivatives	**$ 441,007**	$ 539,964	$ 621,722	**$ 980,971**	$ 1,134,753

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss. See the Financial Instruments and Risk Management note within the consolidated financial statements for the respective period end 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			Six Months Ended	
($ thousands)	**June 30, 2025**	March 31, 2025	June 30, 2024	**June 30, 2025**	June 30, 2024
Cash flows from operating activities	**$ 354,312**	$ 431,317	$ 505,584	**$ 785,629**	$ 889,357
Change in non-cash working capital	**9,042**	29,034	20,140	**38,076**	52,163
Additions to exploration and evaluation assets	**(930)**	—	—	**(930)**	—
Additions to oil and gas properties	**(355,602)**	(405,097)	(339,573)	**(760,699)**	(752,124)
Payments on lease obligations	**(3,634)**	(2,725)	(5,478)	**(6,359)**	(10,350)
Transaction costs	**—**	—	—	**—**	1,539
Free cash flow	**$ 3,188**	$ 52,529	$ 180,673	**$ 55,717**	$ 180,585

Working capital deficiency

Working capital deficiency is calculated as cash, trade receivables, and prepaids and other assets net of trade payables, share-based compensation liability, dividends payable, and other long-term liabilities. Working capital deficiency is used by management to measure the Company's liquidity. At June 30, 2025, the Company had $1.2 billion of available credit facility capacity to cover any working capital deficiencies.

The following table summarizes the calculation of working capital deficiency.

	As at		
($ thousands)	**June 30, 2025**	March 31, 2025	June 30, 2024
Cash	**$ (7,156)**	$ (5,966)	$ (35,887)
Trade receivables	**(363,507)**	(391,905)	(429,098)
Prepaids and other assets	**(75,856)**	(72,045)	(81,805)
Trade payables	**538,330**	582,053	617,222
Share-based compensation liability	**13,851**	12,602	22,706
Dividends payable	**17,304**	17,334	19,845
Other long-term liabilities	**19,751**	20,849	18,161
Working capital deficiency	**$ 142,717**	$ 162,922	$ 131,144

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 divided by barrels of oil equivalent production volume for the applicable period.

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 and is used to assess our operating performance on a unit of production basis.

Capital Management Measures

Net debt

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

The following table summarizes our calculation of net debt.

	As at		
($ thousands)	**June 30, 2025**	March 31, 2025	June 30, 2024
Credit facilities	**$ 317,310**	$ 234,683	$ 607,589
Unamortized debt issuance costs - Credit facilities (1)	**16,206**	15,601	18,387
Long-term notes	**1,776,647**	1,930,809	1,833,182
Unamortized debt issuance costs - Long-term notes (1)	**41,060**	46,235	48,712
Trade payables	**538,330**	582,053	617,222
Share-based compensation liability	**13,851**	12,602	22,706
Dividends payable	**17,304**	17,334	19,845
Other long-term liabilities	**19,751**	20,849	18,161
Cash	**(7,156)**	(5,966)	(35,887)
Trade receivables	**(363,507)**	(391,905)	(429,098)
Prepaids and other assets	**(75,856)**	(72,045)	(81,805)
Net debt	**$ 2,293,940**	$ 2,390,250	$ 2,639,014

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

Adjusted funds flow

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

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

	Three Months Ended			Six Months Ended	
($ thousands)	**June 30, 2025**	March 31, 2025	June 30, 2024	**June 30, 2025**	June 30, 2024
Cash flow from operating activities	**$ 354,312**	$ 431,317	$ 505,584	**$ 785,629**	$ 889,357
Change in non-cash working capital	**9,042**	29,034	20,140	**38,076**	52,163
Asset retirement obligations settled	**3,565**	3,519	7,115	**7,084**	13,626
Transaction costs	**—**	—	—	**—**	1,539
Adjusted funds flow	**$ 366,919**	$ 463,870	$ 532,839	**$ 830,789**	$ 956,685

<u>Advisory Regarding Oil and Gas Information</u>

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 peak 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.

Throughout this press release, “oil and NGL” refers to heavy crude oil, bitumen, light and medium crude oil, tight oil, condensate and natural gas liquids (“NGL”) product types as defined by NI 51-101. The following table shows Baytex’s disaggregated production volumes for the three and six months ended June 30, 2025 and 2024. The NI 51-101 product types are included as follows: “Heavy Crude Oil” - heavy crude oil and bitumen, “Light and Medium Crude Oil” - light and medium crude oil, tight oil and condensate, “NGL” - natural gas liquids and “Natural Gas” - shale gas and conventional natural gas.

	Three Months Ended June 30, 2025					**Three Months Ended June 30, 2024**				
	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	9,308	14	34	9,845	10,997	9,116	7	41	10,733	10,953
Lloydminster	12,456	20	—	1,148	12,667	13,688	16	—	1,607	13,972
Peavine	19,662	—	—	—	19,662	19,938	—	—	—	19,938
Remaining Properties	1,439	2	—	770	1,569	957	1	—	535	1,047
Canada - Light										
Viking	89	7,603	198	10,761	9,684	—	8,130	181	10,586	10,075
Duvernay	—	3,180	2,166	7,915	6,665	—	2,509	1,640	5,875	5,128
Remaining Properties	5	348	588	11,892	2,923	4	413	447	10,263	2,575
United States										
Eagle Ford	—	50,941	16,962	96,151	83,928	—	55,955	17,858	100,165	90,506
Total	42,959	62,108	19,948	138,482	148,095	43,703	67,031	20,167	139,764	154,194

	Six Months Ended June 30, 2025					Six Months Ended June 30, 2024				
	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	9,758	12	26	9,734	11,418	9,299	8	44	10,411	11,086
Lloydminster	11,905	17	—	1,169	12,117	13,422	15	—	1,519	13,690
Peavine	18,693	—	—	—	18,693	18,768	—	—	—	18,768
Remaining Properties	1,122	1	—	707	1,241	635	47	—	267	727
Canada - Light										
Viking	100	8,277	176	10,541	10,310	—	8,655	185	10,827	10,645
Duvernay	—	2,794	2,193	7,313	6,206	—	2,156	1,699	5,665	4,799
Remaining Properties	5	368	659	13,569	3,294	7	404	542	13,301	3,169
United States										
Eagle Ford	—	50,752	16,445	94,081	82,877	—	55,249	17,263	102,069	89,523
Total	41,583	62,221	19,499	137,114	146,156	42,131	66,534	19,733	144,059	152,407

Baytex Energy Corp.

Baytex Energy Corp. is an energy company with headquarters based in Calgary, Alberta and offices in Houston, Texas. The Company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. Baytex's common shares trade on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE.

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

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

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Email: investor@baytexenergy.com

Exhibit 99.2

BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three and six months ended June 30, 2025 and 2024
Dated July 31, 2025

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and six months ended June 30, 2025. This information is provided as of July 31, 2025. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three and six months ended June 30, 2025 ("Q2/2025" and "YTD 2025") have been compared with the results for the three and six months ended June 30, 2024 ("Q2/2024" and "YTD 2024"). This MD&A should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements ("consolidated financial statements") for the three and six months ended June 30, 2025, its audited comparative consolidated financial statements for the years ended December 31, 2024 and 2023, together with the accompanying notes, and its Annual Information Form ("AIF") for the year ended December 31, 2024. These documents and additional information about Baytex are accessible on the SEDAR+ website at www.sedarplus.ca and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

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

This MD&A contains forward-looking information and statements along with certain measures which do not have any standardized meaning in accordance with International Financial Reporting Standards ("IFRS") as prescribed by the International Accounting Standards Board. The terms "operating netback", "free cash flow", "average royalty rate", "heavy oil, net of blending and other expense" and "total sales, net of blending and other expense" are specified financial measures that do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. This MD&A also contains the terms "adjusted funds flow" and "net debt" 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 North American focused oil and gas company based in Calgary, Alberta. The Company operates in Canada and the United States ("U.S."). The Canadian operating segment includes our light oil assets in the Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford operated and non-operated assets in Texas.

SECOND QUARTER HIGHLIGHTS

Baytex delivered strong operating and financial results in Q2/2025. Production of 148,095 boe/d and exploration and development expenditures of $356.5 million for Q2/2025 were consistent with our full-year plan and reflect our successful development programs in the U.S. and Canada. In the U.S., we successfully completed two refracs on our operated Eagle Ford properties that extend inventory duration and improve capital efficiencies. In Canada, we achieved record well performance in our Duvernay light oil operations and delivered a 7% increase in production from our heavy oil properties.

We spent $356.5 million on exploration and development expenditures in Q2/2025, compared to $339.6 million in Q2/2024 and consistent with our full year plans to spend approximately $1.2 billion. In the U.S., we invested $208.8 million and production averaged 83,928 boe/d during Q2/2025 compared to exploration and development expenditures of $237.7 million and production of 90,506 boe/d for Q2/2024. In Canada, we invested $147.7 million and generated production of 64,167 boe/d in Q2/2025 compared to exploration and development expenditures of $101.9 million and production of 63,688 boe/d in Q2/2024.

Oil prices were volatile during Q2/2025 due to geopolitical events along with concerns over global economic conditions. The WTI benchmark price for Q2/2025 was US$63.74/bbl which was lower than Q2/2024 when WTI averaged US$80.57/bbl. Adjusted funds flow[(1)] of $366.9 million and cash flows from operating activities of $354.3 million for Q2/2025 were primarily a result of lower realized pricing compared to Q2/2024 when we generated adjusted funds flow of $532.8 million and cash flows from operating activities of $505.6 million.

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

Net debt[1] of $2.3 billion at June 30, 2025 was $123.2 million lower than at December 31, 2024. Free cash flow[2] of $55.7 million generated in YTD 2025 was allocated to debt repayment along with $51.4 million of shareholder returns including share buybacks and quarterly dividends. We expect net debt to decline over the remainder of 2025 as we continue to allocate free cash flow to the balance sheet after funding our dividend.

(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.

2025 GUIDANCE

We continue to execute our 2025 plan and anticipate full year production of approximately 148,000 boe/d and exploration and development expenditures of approximately $1.2 billion, consistent with our previous guidance. We have fine-tuned several of our cost assumptions to reflect lower production and lower commodity prices. The following table compares our 2025 annual guidance to our YTD 2025 results.

	2025 Annual Guidance (1)	Revised Annual Guidance	YTD 2025 Results
Exploration and development expenditures	$1.2 - $1.3 billion	~ $1.2 billion	$761.6 million
Production (boe/d)	148,000 - 152,000 (2)	~148,000	146,156
Expenses:			
Average royalty rate (3)	~ 23%	~ 22%	22.0 %
Operating (4)	$11.75 - $12.50/boe	no change	$11.67/boe
Transportation (4)	$2.40 - $2.55/boe	no change	$2.40/boe
General and administrative (4)	$90 million ($1.67/boe) (5)	$95 million ($1.76/boe)	$47.8 million ($1.81/boe)
Cash interest (4)	$180 million ($3.33/boe) (5)	no change	$91.7 million ($3.46/boe)
Current income tax	~ 1% of EBITDA (6)	no change	0.7% of EBITDA (6)
Leasing expenditures	$10 million	$15 million	$6.4 million
Asset retirement obligations	$25 million	$20 million	$7.1 million

(1) As announced on December 3, 2024.
(2) As announced December 20, 2024 in conjunction with the Kerrobert Thermal asset sale.
(3) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(4) Refer to Operating Expense, Transportation Expense, General and Administrative Expense and Financing and Interest Expense sections of this MD&A for a description of the composition of these measures.
(5) Per boe amounts for general and administrative and cash interest have been updated to reflect the low end of the production guidance range.
(6) EBITDA is calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.

RESULTS OF OPERATIONS

The Canadian operating segment includes our light oil assets in Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our operated and non-operated Eagle Ford assets in Texas.

Production

Three Months Ended June 30						
	2025			2024		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**11,167**	**50,941**	**62,108**	11,076	55,955	67,031
Heavy oil	**42,959**	**—**	**42,959**	43,703	—	43,703
Natural Gas Liquids (NGL)	**2,986**	**16,962**	**19,948**	2,309	17,858	20,167
Total liquids (bbl/d)	**57,112**	**67,903**	**125,015**	57,088	73,813	130,901
Natural gas (mcf/d)	**42,331**	**96,151**	**138,482**	39,599	100,165	139,764
Total production (boe/d)	**64,167**	**83,928**	**148,095**	63,688	90,506	154,194
Production Mix						
Segment as a percent of total	**43 %**	**57 %**	**100 %**	41 %	59 %	100 %
Light oil and condensate	**17 %**	**61 %**	**42 %**	17 %	62 %	44 %
Heavy oil	**67 %**	**— %**	**29 %**	69 %	— %	28 %
NGL	**5 %**	**20 %**	**13 %**	4 %	20 %	13 %
Natural gas	**11 %**	**19 %**	**16 %**	10 %	18 %	15 %

Six Months Ended June 30						
	2025			2024		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**11,469**	**50,752**	**62,221**	11,285	55,249	66,534
Heavy oil	**41,583**	**—**	**41,583**	42,131	—	42,131
Natural Gas Liquids (NGL)	**3,054**	**16,445**	**19,499**	2,470	17,263	19,733
Total liquids (bbl/d)	**56,106**	**67,197**	**123,303**	55,886	72,512	128,398
Natural gas (mcf/d)	**43,033**	**94,081**	**137,114**	41,990	102,069	144,059
Total production (boe/d)	**63,279**	**82,877**	**146,156**	62,884	89,523	152,407
Production Mix						
Segment as a percent of total	**43 %**	**57 %**	**100 %**	41 %	59 %	100 %
Light oil and condensate	**18 %**	**61 %**	**43 %**	18 %	62 %	44 %
Heavy oil	**66 %**	**— %**	**28 %**	67 %	— %	28 %
NGL	**5 %**	**20 %**	**13 %**	4 %	19 %	13 %
Natural gas	**11 %**	**19 %**	**16 %**	11 %	19 %	15 %

Production was 148,095 boe/d for Q2/2025 and 146,156 boe/d for YTD 2025 compared to 154,194 boe/d for Q2/2024 and 152,407 boe/d for YTD 2024 which reflects lower development on our non-operated Eagle Ford assets and the disposition of non-core heavy oil assets in Q4/2024.

In Canada, production was 64,167 boe/d for Q2/2025 and 63,279 boe/d for YTD 2025 compared to 63,688 boe/d for Q2/2024 and 62,884 boe/d for YTD 2024. Our successful light and heavy oil development programs resulted in production that was 479 boe/d higher for Q2/2025 and 395 boe/d higher for YTD 2025 relative to the same periods of 2024 despite the disposition of 2,000 boe/d of heavy oil production from the Kerrobert thermal assets in Q4/2024.

In the U.S., production was 83,928 boe/d for Q2/2025 and 82,877 for YTD 2025 compared to 90,506 boe/d for Q2/2024 and 89,523 boe/d for YTD 2024. Lower production for both periods of 2025 reflects reduced non-operated Eagle Ford activity in late 2024 and early 2025. We initiated production from 19 (14.9 net) wells during Q2/2025 and 46 (30.6 net) wells during YTD 2025 compared to 30 (14.8 net) wells during Q2/2024 and 67 (37.2 net) wells during YTD 2024.

Total production of 146,156 boe/d for YTD 2025 is consistent with expectations. We are expecting production of approximately 148,000 boe/d for 2025 which reflects average production of approximately 150,000 boe/d over the second half of 2025.

COMMODITY PRICES

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

Crude Oil

During Q2/2025 and YTD 2025, global benchmark prices for crude oil were lower compared to the same periods of 2024 as a result of increasing supply, geopolitical events and concerns over slowing global economic activity. The WTI benchmark price averaged US$63.74/bbl for Q2/2025 and US$67.58/bbl for YTD 2025 compared to US$80.57/bbl for Q2/2024 and US$78.77/bbl for YTD 2024.

We compare the price received for our U.S. crude oil production to the Magellan East Houston ("MEH") stream at Houston, Texas which is a representative benchmark for light oil pricing at the U.S. Gulf Coast. The MEH benchmark averaged US$65.56/bbl during Q2/2025 and US$69.47/bbl during YTD 2025 compared to US$83.10/bbl for Q2/2024 and US$81.03/bbl for YTD 2024, and typically trades at a premium to WTI as a result of access to global markets. The MEH benchmark premium to WTI was US$1.82/bbl for Q2/2025 and US$1.89/bbl for YTD 2025 compared to premiums of US$2.53/bbl for Q2/2024 and US$2.26/bbl for YTD 2024.

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets and the cost of transportation from Western Canada. Differentials for Canadian oil prices relative to WTI fluctuate from period to period based on production and inventory levels in Western Canada. Canadian oil differentials were narrower in Q2/2025 and YTD 2025 relative to both periods of 2024 after exports commenced from the TMX pipeline expansion in May 2024.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $84.15/bbl during Q2/2025 and $89.71/bbl during YTD 2025 compared to $105.30/bbl during Q2/2024 and $98.73/bbl during YTD 2024. Edmonton par traded at a discount to WTI of US$2.94/bbl for Q2/2025 and $3.93/bbl for YTD 2025 compared to a discount of US$3.62/bbl for Q2/2024 and $6.10/bbl for YTD 2024.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS benchmark for Q2/2025 averaged $74.10/bbl and $79.15/bbl for YTD 2025 compared to $91.72/bbl for Q2/2024 and $84.68/bbl for YTD 2024. The WCS heavy oil differential to WTI was US$10.20/bbl in Q2/2025 and US$11.43/bbl in YTD 2025 compared to US$13.55/bbl for Q2/2024 and US$16.44/bbl for YTD 2024.

Natural Gas

Natural gas prices in Canada and the U.S. were higher in both periods of 2025 compared to 2024 and reflect incremental demand from cold winter weather and lower inventory levels.

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. The NYMEX natural gas benchmark averaged US$3.44/mmbtu for Q2/2025 and US$3.55/mmbtu for YTD 2025 compared to US$1.89/mmbtu for Q2/2024 and US$2.07/mmbtu for YTD 2024.

In Canada, we receive natural gas pricing based on the AECO benchmark which trades at a discount to NYMEX as a result of limited market access for Canadian natural gas production. The AECO benchmark averaged $2.07/mcf during Q2/2025 and $2.05/mcf for YTD 2025 which is higher than $1.44/mcf for Q2/2024 and $1.74/mcf for YTD 2024.

The following tables compare select benchmark prices and our average realized selling prices for the three and six months ended June 30, 2025 and 2024.

	Three Months Ended June 30			Six Months Ended June 30		
	2025	2024	Change	**2025**	2024	Change
Benchmark Averages						
WTI oil (US$/bbl) (1)	**63.74**	80.57	(16.83)	**67.58**	78.77	(11.19)
MEH oil (US$/bbl) (2)	**65.56**	83.10	(17.54)	**69.47**	81.03	(11.56)
MEH oil differential to WTI (US$/bbl)	**1.82**	2.53	(0.71)	**1.89**	2.26	(0.37)
Edmonton par oil ($/bbl) (3)	**84.15**	105.30	(21.15)	**89.71**	98.73	(9.02)
Edmonton par oil differential to WTI (US$/bbl)	**(2.94)**	(3.62)	0.68	**(3.93)**	(6.10)	2.17
WCS heavy oil ($/bbl) (4)	**74.10**	91.72	(17.62)	**79.15**	84.68	(5.53)
WCS heavy oil differential to WTI (US$/bbl)	**(10.20)**	(13.55)	3.35	**(11.43)**	(16.44)	5.01
AECO natural gas ($/mcf) (5)	**2.07**	1.44	0.63	**2.05**	1.74	0.31
NYMEX natural gas (US$/mmbtu) (6)	**3.44**	1.89	1.55	**3.55**	2.07	1.48
CAD/USD average exchange rate	**1.3840**	1.3684	0.0156	**1.4095**	1.3586	0.0509

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) MEH refers to arithmetic average of the Argus WTI Houston differential weighted index price for the applicable period.
(3) Edmonton par refers to the average posting price for the benchmark MSW crude oil.
(4) WCS refers to the average posting price for the benchmark WCS heavy oil.
(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(6) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Three Months Ended June 30					
	2025			2024		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) (1)	**$ 82.54**	**$ 86.73**	**$ 85.98**	$ 103.21	$ 109.71	$ 108.64
Heavy oil, net of blending and other expense ($/bbl) (2)	**64.43**	**—**	**64.43**	82.29	—	82.29
NGL ($/bbl) (1)	**22.93**	**26.17**	**25.68**	24.48	27.30	26.98
Natural gas ($/mcf) (1)	**1.73**	**3.78**	**3.16**	1.23	2.37	2.04
Total sales, net of blending and other expense ($/boe) (2)	**$ 59.71**	**$ 62.26**	**$ 61.16**	$ 76.07	$ 75.83	$ 75.93

	Six Months Ended June 30					
	2025			2024		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) (1)	**$ 88.32**	**$ 93.68**	**$ 92.69**	$ 97.02	$ 105.87	$ 104.37
Heavy oil, net of blending and other expense ($/bbl) (2)	**68.79**	**—**	**68.79**	74.07	—	74.07
NGL ($/bbl) (1)	**25.54**	**28.95**	**28.42**	25.61	26.71	26.57
Natural gas ($/mcf) (1)	**1.89**	**4.33**	**3.57**	1.86	2.37	2.22
Total sales, net of blending and other expense ($/boe) (2)	**$ 63.74**	**$ 68.03**	**$ 66.17**	$ 69.29	$ 73.19	$ 71.58

(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.
(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.

Average Realized Sales Prices

Our total sales, net of blending and other expense per boe[1] was $61.16/boe for Q2/2025 and $66.17/boe for YTD 2025 compared to $75.93/boe for Q2/2024 and $71.58/boe for YTD 2024. Our average realized sales price decreased due to lower WTI pricing partially offset by narrower Canadian oil differentials, higher natural gas prices and improved NGL realizations.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price[2] represents a discount to the Edmonton par price of $1.61/bbl for Q2/2025 and $1.39/bbl for YTD 2025 which is consistent with discounts of $2.09/bbl in Q2/2024 and $1.71/bbl in YTD 2024.

The price received for our U.S. light oil and condensate production is based on the MEH benchmark. Expressed in U.S. dollars, our realized light oil and condensate price[2] represents a discount to MEH of US$2.89/bbl for Q2/2025 and $3.01/bbl for YTD 2025 consistent with a discount of US$2.93/bbl for Q2/2024 and $3.10/bbl for YTD 2024.

Our realized heavy oil price, net of blending and other expense[1] was lower in Q2/2025 and YTD 2025 compared to the same periods of 2024 which reflects the decrease in WCS benchmark pricing. Our realized pricing for Q2/2025 and YTD 2025 represents a discount to the WCS benchmark of $9.67/bbl and $10.36/bbl compared to $9.43/bbl and $10.61/bbl for the same periods of 2024.

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[2] was 29% of WTI in Q2/2025 and 30% of WTI in YTD 2025, which reflects strong ethane pricing compared to 24% of WTI in Q2/2024 and 25% of WTI for YTD 2024.

We compare our realized natural gas price in the U.S. to the NYMEX benchmark and to the AECO benchmark price in Canada. The increase in AECO and NYMEX benchmark prices for Q2/2025 and YTD 2025 resulted in higher realized natural gas pricing in Canada and the U.S. relative to both periods of 2024.

(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) 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.

PETROLEUM AND NATURAL GAS SALES

	Three Months Ended June 30					
	2025			2024		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 83,876**	**$ 402,046**	**$ 485,922**	$ 104,030	$ 558,620	$ 662,650
Heavy oil	**314,254**	**—**	**314,254**	394,960	—	394,960
NGL	**6,232**	**40,390**	**46,622**	5,144	44,366	49,510
Total oil sales	**404,362**	**442,436**	**846,798**	504,134	602,986	1,107,120
Natural gas sales	**6,674**	**33,107**	**39,781**	4,426	21,577	26,003
Total petroleum and natural gas sales	**411,036**	**475,543**	**886,579**	508,560	624,563	1,133,123
Blending and other expense	**(62,381)**	**—**	**(62,381)**	(67,685)	—	(67,685)
Total sales, net of blending and other expense (1)	**$ 348,655**	**$ 475,543**	**$ 824,198**	$ 440,875	$ 624,563	$ 1,065,438

	Six Months Ended June 30					
	2025			2024		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 183,344**	**$ 860,540**	**$ 1,043,884**	$ 199,251	$ 1,064,514	$ 1,263,765
Heavy oil	**652,965**	**—**	**652,965**	699,884	—	699,884
NGL	**14,121**	**86,178**	**100,299**	11,513	83,928	95,441
Total oil sales	**850,430**	**946,718**	**1,797,148**	910,648	1,148,442	2,059,090
Natural gas sales	**14,757**	**73,804**	**88,561**	14,225	44,000	58,225
Total petroleum and natural gas sales	**865,187**	**1,020,522**	**1,885,709**	924,873	1,192,442	2,117,315
Blending and other expense	**(135,201)**	**—**	**(135,201)**	(131,893)	—	(131,893)
Total sales, net of blending and other expense (1)	**$ 729,986**	**$ 1,020,522**	**$ 1,750,508**	$ 792,980	$ 1,192,442	$ 1,985,422

(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, was $824.2 million for Q2/2025 and $1.8 billion for YTD 2025 compared to $1.1 billion for Q2/2024 and $2.0 billion for YTD 2024. The decrease in total sales, net of blending and other expense reflects lower realized pricing and lower production in both periods of 2025 compared to 2024.

In Canada, total sales, net of blending and other expense, of $348.7 million for Q2/2025 and $730.0 million for YTD 2025 decreased from $440.9 million reported for Q2/2024 and $793.0 million for YTD 2024. The decrease in benchmark prices in Q2/2025 and YTD 2025 relative to Q2/2024 and YTD 2024 was the primary factor that resulted in lower total sales, net of blending and other expense over the same periods.

In the U.S., total petroleum and natural gas sales of $475.5 million for Q2/2025 and $1.0 billion for YTD 2025 decreased from $624.6 million reported for Q2/2024 and $1.2 billion for YTD 2024. Lower realized pricing resulted in a $103.6 million decrease in total sales in Q2/2025 relative to Q2/2024 while lower production contributed to a $45.4 million decrease in total sales relative to Q2/2024. Lower realized pricing resulted in a $77.3 million decrease in total sales in YTD 2025 relative to YTD 2024 while lower production contributed to a $94.6 million decrease in total sales relative to YTD 2024.

ROYALTIES

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three and six months ended June 30, 2025 and 2024.

	Three Months Ended June 30					
	2025			2024		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 47,800**	**$ 129,590**	**$ 177,390**	$ 72,894	$ 167,546	$ 240,440
Average royalty rate (1)(2)	**13.7 %**	**27.3 %**	**21.5 %**	16.5 %	26.8 %	22.6 %
Royalties per boe (3)	**$ 8.19**	**$ 16.97**	**$ 13.16**	$ 12.58	$ 20.34	$ 17.14

	Six Months Ended June 30					
	2025			2024		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 107,056**	**$ 278,271**	**$ 385,327**	$ 129,458	$ 320,153	$ 449,611
Average royalty rate (1)(2)	**14.7 %**	**27.3 %**	**22.0 %**	16.3 %	26.8 %	22.6 %
Royalties per boe (3)	**$ 9.35**	**$ 18.55**	**$ 14.57**	$ 11.31	$ 19.65	$ 16.21

(1) Average royalty rate is calculated as royalties divided by total sales, net of blending and other expense.
(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) Royalties per boe is calculated as royalties divided by barrels of oil equivalent production volume for the applicable period.

Royalties for Q2/2025 were $177.4 million or 21.5% of total sales, net of blending and other expense, compared to $240.4 million or 22.6% for Q2/2024. Total royalties for YTD 2025 were $385.3 million or 22.0% of total sales, net of blending and other expense, compared to $449.6 million or 22.6% for YTD 2024. Total royalty expense was lower for Q2/2025 and YTD 2025 due to lower total sales, net of blending and other expense, relative to the same periods of 2024.

Our average royalty rate in Canada of 13.7% for Q2/2025 and 14.7% for YTD 2025 was lower than 16.5% for Q2/2024 and 16.3% for YTD 2024 due to lower benchmark commodity prices. In the U.S., our average royalty rate was 27.3% for both periods of 2025 which was relatively consistent with 26.8% for both periods of 2024.

Our average royalty rate of 22.0% for YTD 2025 is consistent with expectations and we have updated our annual guidance to approximately 22% for 2025.

OPERATING EXPENSE

	Three Months Ended June 30					
	2025			2024		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 88,035**	**$ 72,985**	**$ 161,020**	$ 84,415	$ 83,290	$ 167,705
Operating expense per boe (1)	**$ 15.08**	**$ 9.56**	**$ 11.95**	$ 14.57	$ 10.11	$ 11.95

	Six Months Ended June 30					
	2025			2024		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 163,615**	**$ 145,108**	**$ 308,723**	$ 169,818	$ 171,322	$ 341,140
Operating expense per boe (1)	**$ 14.29**	**$ 9.67**	**$ 11.67**	$ 14.84	$ 10.51	$ 12.30

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

Total operating expense was $161.0 million ($11.95/boe) for Q2/2025 and $308.7 million ($11.67/boe) for YTD 2025 compared to $167.7 million ($11.95/boe) for Q2/2024 and $341.1 million ($12.30/boe) for YTD 2024. Total operating expense for both periods of 2025 decreased relative to 2024 due to lower production while per unit operating costs were relatively consistent over the same periods.

In Canada, total operating expense was $88.0 million ($15.08/boe) for Q2/2025 and $163.6 million ($14.29/boe) for YTD 2025 compared to $84.4 million ($14.57/boe) for Q2/2024 and $169.8 million ($14.84/boe) for YTD 2024. Operating expense in Canada for Q2/2025 has increased with higher production relative to Q2/2024 while per unit operating expense of $15.08/boe for Q2/2025 and $14.29/boe for YTD 2025 was relatively consistent with $14.57/boe for Q2/2024 and $14.84/boe for YTD 2024.

In the U.S., operating expense was $73.0 million ($9.56/boe) for Q2/2025 and $145.1 million ($9.67/boe) for YTD 2025 which was lower than $83.3 million ($10.11/boe) for Q2/2024 and $171.3 million ($10.51/boe) for YTD 2024. Per boe operating expense in the U.S., expressed in U.S. dollars, was US$6.91/boe for Q2/2025 and US$6.86/boe for YTD 2025 which was lower than US$7.39/boe for Q2/2024 and US$7.74/boe for YTD 2024. The decrease in total and per unit operating expense reflects our cost savings initiatives and lower production in both periods of 2025 compared to 2024.

Operating expense of $11.67/boe for YTD 2025 is consistent with expectations and slightly below our annual guidance range of $11.75 - $12.50/boe for 2025.

TRANSPORTATION EXPENSE

Transportation expense includes the costs incurred to move production via truck or pipeline to the sales point. Transportation expense can vary from period to period as we seek to optimize sales prices and transportation rates.

The following table compares our transportation expense for the three and six months ended June 30, 2025 and 2024.

	Three Months Ended June 30					
	2025			2024		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 20,544**	**$ 12,363**	**$ 32,907**	$ 19,569	$ 13,745	$ 33,314
Transportation expense per boe (1)	**$ 3.52**	**$ 1.62**	**$ 2.44**	$ 3.38	$ 1.67	$ 2.37

	Six Months Ended June 30					
	2025			2024		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 39,323**	**$ 24,096**	**$ 63,419**	$ 37,779	$ 25,370	$ 63,149
Transportation expense per boe (1)	**$ 3.43**	**$ 1.61**	**$ 2.40**	$ 3.30	$ 1.56	$ 2.28

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

Transportation expense was $32.9 million ($2.44/boe) for Q2/2025 and $63.4 million ($2.40/boe) for YTD 2025 consistent with $33.3 million ($2.37/boe) for Q2/2024 and $63.1 million ($2.28/boe) for YTD 2024.

Per unit transportation expense of $2.40/boe for YTD 2025 is consistent with expectations and our annual guidance range of $2.40 - $2.55/boe for 2025.

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 $62.4 million for Q2/2025 and $135.2 million for YTD 2025 compared to $67.7 million for Q2/2024 and $131.9 million for YTD 2024. Blending and other expense for Q2/2025 was comparable to Q2/2024 and YTD 2024 as heavy oil production was relatively consistent over the same periods.

FINANCIAL DERIVATIVES

Our business is exposed to fluctuations in commodity prices, foreign exchange rates, interest rates and changes in our share price. We utilize various financial derivative contracts which are intended to partially reduce the volatility in our free cash flow caused by these exposures. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the three and six months ended June 30, 2025 and 2024.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2025**	2024	Change	**2025**	2024	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ (12,448)**	$ (4,847)	$ (7,601)	**$ (13,281)**	$ (3,900)	$ (9,381)
Natural gas	**574**	2,590	(2,016)	**1,213**	7,131	(5,918)
Total	**$ (11,874)**	$ (2,257)	$ (9,617)	**$ (12,068)**	$ 3,231	$ (15,299)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ 18,426**	$ 13,476	$ 4,950	**$ (15,615)**	$ (17,989)	$ 2,374
Natural gas	**12,111**	(2,686)	14,797	**(3,273)**	(3,571)	298
Total	**$ 30,537**	$ 10,790	$ 19,747	**$ (18,888)**	$ (21,560)	$ 2,672
Total financial derivatives gain (loss)						
Crude oil	**$ 5,978**	$ 8,629	$ (2,651)	**$ (28,896)**	$ (21,889)	$ (7,007)
Natural gas	**12,685**	(96)	12,781	**(2,060)**	3,560	(5,620)
Total	**$ 18,663**	$ 8,533	$ 10,130	**$ (30,956)**	$ (18,329)	$ (12,627)

We recorded a total financial derivatives gain of $18.7 million for Q2/2025 and a loss of $31.0 million for YTD 2025 compared to a gain of $8.5 million for Q2/2024 and a loss of $18.3 million for YTD 2024. The realized financial derivatives loss of $12.1 million for YTD 2025 resulted from losses of $13.3 million on crude oil contracts and gains of $1.2 million on natural gas contracts. The unrealized financial derivatives loss of $18.9 million for YTD 2025 resulted from a $15.6 million loss on crude oil contracts and a $3.3 million loss on natural gas contracts. The fair value of our financial derivative contracts resulted in a net asset of $5.0 million at June 30, 2025 compared to a net asset of $23.9 million at December 31, 2024.

Refer to Note 16 of the consolidated financial statements for a complete listing of our outstanding contracts at July 31, 2025.

OPERATING NETBACK

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the three and six months ended June 30, 2025 and 2024.

	Three Months Ended June 30					
	2025			2024		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**64,167**	**83,928**	**148,095**	63,688	90,506	154,194
Operating netback:						
Total sales, net of blending and other expense (1)	**$ 59.71**	**$ 62.26**	**$ 61.16**	$ 76.07	$ 75.83	$ 75.93
Less:						
Royalties (2)	**(8.19)**	**(16.97)**	**(13.16)**	(12.58)	(20.34)	(17.14)
Operating expense (2)	**(15.08)**	**(9.56)**	**(11.95)**	(14.57)	(10.11)	(11.95)
Transportation expense (2)	**(3.52)**	**(1.62)**	**(2.44)**	(3.38)	(1.67)	(2.37)
Operating netback (1)	**$ 32.92**	**$ 34.11**	**$ 33.61**	$ 45.54	$ 43.71	$ 44.47
Realized financial derivatives loss (3)	**—**	**—**	**(0.88)**	—	—	(0.16)
Operating netback after financial derivatives (1)	**$ 32.92**	**$ 34.11**	**$ 32.73**	$ 45.54	$ 43.71	$ 44.31

	Six Months Ended June 30					
	2025			2024		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**63,279**	**82,877**	**146,156**	62,884	89,523	152,407
Operating netback:						
Total sales, net of blending and other expense (1)	**$ 63.74**	**$ 68.03**	**$ 66.17**	$ 69.29	$ 73.19	$ 71.58
Less:						
Royalties (2)	**(9.35)**	**(18.55)**	**(14.57)**	(11.31)	(19.65)	(16.21)
Operating expense (2)	**(14.29)**	**(9.67)**	**(11.67)**	(14.84)	(10.51)	(12.30)
Transportation expense (2)	**(3.43)**	**(1.61)**	**(2.40)**	(3.30)	(1.56)	(2.28)
Operating netback (1)	**$ 36.67**	**$ 38.20**	**$ 37.53**	$ 39.84	$ 41.47	$ 40.79
Realized financial derivatives (loss) gain (3)	**—**	**—**	**(0.46)**	—	—	0.12
Operating netback after financial derivatives (1)	**$ 36.67**	**$ 38.20**	**$ 37.07**	$ 39.84	$ 41.47	$ 40.91

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Refer to Royalties, Operating Expense and Transportation Expense sections in this MD&A for a description of the composition these measures.
(3) Calculated as realized financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

Our operating netback of $33.61/boe for Q2/2025 and $37.53/boe for YTD 2025 was lower than $44.47/boe for Q2/2024 and $40.79/boe for YTD 2024 due to the decrease in our realized price which resulted in lower per unit sales net of royalties. Total operating and transportation expense for Q2/2025 and YTD 2025 was consistent with the same periods of 2024. Our operating netback net of realized gains and losses on financial derivatives was $32.73/boe for Q2/2025 and $37.07/boe for YTD 2025 was lower than $44.31/boe for Q2/2024 and $40.91/boe for YTD 2024 due to the decrease in realized prices.

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. G&A expense fluctuates with head office staffing levels and the level of operated exploration and development activity during the period.

The following table summarizes our G&A expense for the three and six months ended June 30, 2025 and 2024.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2025**	2024	Change	**2025**	2024	Change
Gross general and administrative expense	**$ 28,859**	$ 27,064	$ 1,795	**$ 61,522**	$ 55,827	$ 5,695
Overhead recoveries	**(6,639)**	(6,058)	(581)	**(13,696)**	(12,409)	(1,287)
General and administrative expense	**$ 22,220**	$ 21,006	$ 1,214	**$ 47,826**	$ 43,418	$ 4,408
General and administrative expense per boe (1)	**$ 1.65**	$ 1.50	$ 0.15	**$ 1.81**	$ 1.57	$ 0.24

(1) 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.

G&A expense was $22.2 million ($1.65/boe) for Q2/2025 and $47.8 million ($1.81/boe) for YTD 2025 compared to $21.0 million ($1.50/boe) for Q2/2024 and $43.4 million ($1.57/boe) for YTD 2024. G&A expense of $47.8 million ($1.81/boe) for YTD 2025 is consistent with expectations and our revised 2025 annual guidance of approximately $95.0 million ($1.76/boe) which reflects the timing of certain costs and our expectations for production over the remainder of 2025.

FINANCING AND INTEREST EXPENSE

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

The following table summarizes our financing and interest expense for the three and six months ended June 30, 2025 and 2024.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2025**	2024	Change	**2025**	2024	Change
Interest on credit facilities	**$ 6,855**	$ 15,639	$ (8,784)	**$ 13,038**	$ 33,928	$ (20,890)
Interest on long-term notes	**37,683**	37,656	27	**77,962**	72,334	5,628
Interest on lease obligations	**337**	651	(314)	**662**	964	(302)
Cash interest	**$ 44,875**	$ 53,946	$ (9,071)	**$ 91,662**	$ 107,226	$ (15,564)
Accretion of debt issue costs	**3,926**	7,862	(3,936)	**6,736**	10,922	(4,186)
Accretion of asset retirement obligations	**5,667**	5,459	208	**11,316**	10,386	930
Gain on repurchase and cancellation of long-term notes	**(2,755)**	—	(2,755)	**(2,755)**	—	(2,755)
Early redemption expense	**—**	24,350	(24,350)	**—**	24,350	(24,350)
Financing and interest expense	**$ 51,713**	$ 91,617	$ (39,904)	**$ 106,959**	$ 152,884	$ (45,925)
Cash interest per boe (1)	**$ 3.33**	$ 3.84	$ (0.51)	**$ 3.46**	$ 3.87	$ (0.41)
Financing and interest expense per boe (1)	**$ 3.84**	$ 6.53	$ (2.69)	**$ 4.04**	$ 5.51	$ (1.47)

(1) Calculated as cash interest or financing and interest expense divided by barrels of oil equivalent production volume for the applicable period.

Financing and interest expense was $51.7 million ($3.84/boe) for Q2/2025 and $107.0 million ($4.04/boe) for YTD 2025 compared to $91.6 million ($6.53/boe) for Q2/2024 and $152.9 million ($5.51/boe) for YTD 2024. The decrease for both periods of 2025 is due to lower outstanding debt balances for YTD 2025 and early redemption expense recognized in Q2/2024 related to the redemption of the 8.75% senior notes.

Cash interest of $44.9 million ($3.33/boe) for Q2/2025 and $91.7 million ($3.46/boe) for YTD 2025 was lower than $53.9 million ($3.84/boe) for Q2/2024 and $107.2 million ($3.87/boe) for YTD 2024. Lower interest on our credit facilities reflects lower debt balances outstanding in both periods of 2025, while higher interest on long-term notes is a result of additional principal amounts outstanding after the issuance of the 7.375% Senior Notes in Q2/2024. The weighted average interest rate applicable on our credit facilities was 6.5% for Q2/2025 and 6.6% for YTD 2025 compared to 7.9% for Q2/2024 and 8.0% for YTD 2024.

Accretion of asset retirement obligations of $5.7 million for Q2/2025 and $11.3 million for YTD 2025 was consistent with $5.5 million for Q2/2024 and $10.4 million for YTD 2024. Accretion of debt issue costs of $3.9 million for Q2/2025 and $6.7 million for YTD 2025 was lower than $7.9 million for Q2/2024 and $10.9 million for YTD 2024. In Q2/2024, we recorded $24.4 million of early redemption expense related to the redemption of the 8.75% senior notes.

Cash interest expense of $91.7 million ($3.46/boe) for YTD 2025 is consistent with our expectations and our 2025 annual guidance of $180 million ($3.33/boe) as we expect to reduce debt over the remainder of 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 was $0.5 million for Q2/2025 and $0.6 million for YTD 2025 compared to $0.6 million for Q2/2024 and $0.7 million for YTD 2024.

DEPLETION AND DEPRECIATION

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved and probable reserves volumes and the rate of production for the period. The following table summarizes depletion and depreciation expense for the three and six months ended June 30, 2025 and 2024.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2025**	2024	Change	**2025**	2024	Change
Depletion	**$ 318,187**	$ 349,718	$ (31,531)	**$ 634,030**	$ 691,153	$ (57,123)
Depreciation	**3,972**	3,383	589	**8,052**	6,085	1,967
Depletion and depreciation	**$ 322,159**	$ 353,101	$ (30,942)	**$ 642,082**	$ 697,238	$ (55,156)
Depletion and depreciation per boe [1]	**$ 23.90**	$ 25.16	$ (1.26)	**$ 24.27**	$ 25.14	$ (0.87)

(1) 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.

Depletion and depreciation expense was $322.2 million ($23.90/boe) for Q2/2025 and $642.1 million ($24.27/boe) for YTD 2025 compared to $353.1 million ($25.16/boe) for Q2/2024 and $697.2 million ($25.14/boe) for YTD 2024. Total depletion and depreciation expense and depletion and depreciation per boe were lower in Q2/2025 and YTD 2025 relative to Q2/2024 and YTD 2024 due to lower production and a decrease in future development costs for proved plus probable reserves which resulted in a lower depletable base for our oil and gas properties during 2025.

IMPAIRMENT

We assessed our oil and gas properties and exploration and evaluation assets for indicators of impairment or impairment reversal and concluded that the estimation of recoverable amount was not required for any of our cash generating units at June 30, 2025 and December 31, 2024.

SHARE-BASED COMPENSATION EXPENSE

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

We recorded SBC expense of $1.6 million for Q2/2025 and $2.3 million for YTD 2025 compared to $5.6 million for Q2/2024 and $15.1 million for YTD 2024. SBC expense for Q2/2025 and YTD 2025 reflects a decrease in the Company's share price which resulted in lower SBC expense relative to the same periods of 2024.

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 June 30			Six Months Ended June 30		
($ thousands except for exchange rates)	**2025**	2024	Change	**2025**	2024	Change
Unrealized foreign exchange (gain) loss	**$ (100,792)**	$ 19,189	$ (119,981)	**$ (104,267)**	$ 57,907	$ (162,174)
Realized foreign exchange loss (gain)	**206**	866	(660)	**(197)**	2,085	(2,282)
Foreign exchange (gain) loss	**$ (100,586)**	$ 20,055	$ (120,641)	**$ (104,464)**	$ 59,992	$ (164,456)
CAD/USD exchange rates:						
At beginning of period	**1.4379**	1.3533		**1.4405**	1.3205	
At end of period	**1.3622**	1.3687		**1.3622**	1.3687	

We recorded a foreign exchange gain of $100.6 million for Q2/2025 and $104.5 million for YTD 2025 compared to losses of $20.1 million for Q2/2024 and $60.0 million for YTD 2024.

The unrealized foreign exchange gain of $100.8 million for Q2/2025 and $104.3 million for YTD 2025 is related to changes in the reported amount of our U.S. dollar denominated long-term notes and credit facilities due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2025 compared to March 31, 2025 and December 31, 2024. The unrealized foreign exchange loss of $19.2 million for Q2/2024 and $57.9 million for YTD 2024 is related to changes in the reported amount of our long-term notes and credit facilities due to a weakening of the Canadian dollar relative to the U.S. dollar at June 30, 2024 compared to March 31, 2024 and December 31, 2023.

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 functional currency entities. We recorded a realized foreign exchange loss of $0.2 million for Q2/2025 and a gain of $0.2 million for YTD 2025 compared to losses of $0.9 million for Q2/2024 and $2.1 million for YTD 2024.

INCOME TAXES

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2025**	2024	Change	**2025**	2024	Change
Current income tax expense	**$ 4,547**	$ 6,475	$ (1,928)	**$ 6,699**	$ 8,155	$ (1,456)
Deferred income tax expense	**17,911**	22,810	(4,899)	**36,522**	38,611	(2,089)
Total income tax expense	**$ 22,458**	$ 29,285	$ (6,827)	**$ 43,221**	$ 46,766	$ (3,545)

We recorded current income tax expense of $4.5 million for Q2/2025 and $6.7 million for YTD 2025 compared to $6.5 million for Q2/2024 and $8.2 million for YTD 2024. The current income tax expense for both periods of 2025 and 2024 primarily relates to repatriation and related taxes.

We recorded deferred income tax expense of $17.9 million for Q2/2025 and $36.5 million for YTD 2025 compared to $22.8 million for Q2/2024 and $38.6 million for YTD 2024. The deferred tax expense for Q2/2025 decreased compared to Q2/2024 as a result of unrecognized future capital gains on foreign exchange relative to the increase in income generated for the period.

On July 4, 2025, the U.S. enacted a budget reconciliation package known as the One Big Beautiful Bill Act of 2025 ("OBBBA") which includes both tax and non-tax provisions. The changes resulting from the tax provisions in OBBBA are not expected to have a material impact on the Company’s financial results.

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

We remain confident that the tax filings of the affected entities are correct and will defend our tax filing positions. During Q4/2023, 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 reassessments issued by the CRA assert taxes owing by the trusts of $244.8 million, late payment interest of $232.9 million as at the date of reassessments 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 June 2025, the Department of Justice, legal counsel for the Crown, notified Baytex that they intend to abandon 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 for the three and six months ended June 30, 2025 and 2024 are set forth in the following table.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2025**	2024	Change	**2025**	2024	Change
Petroleum and natural gas sales	**$ 886,579**	$ 1,133,123	$ (246,544)	**$ 1,885,709**	$ 2,117,315	$ (231,606)
Royalties	**(177,390)**	(240,440)	63,050	**(385,327)**	(449,611)	64,284
Revenue, net of royalties	**709,189**	892,683	(183,494)	**1,500,382**	1,667,704	(167,322)
Expenses						
Operating	**(161,020)**	(167,705)	6,685	**(308,723)**	(341,140)	32,417
Transportation	**(32,907)**	(33,314)	407	**(63,419)**	(63,149)	(270)
Blending and other	**(62,381)**	(67,685)	5,304	**(135,201)**	(131,893)	(3,308)
Operating netback (1)	**$ 452,881**	$ 623,979	$ (171,098)	**$ 993,039**	$ 1,131,522	$ (138,483)
General and administrative	**(22,220)**	(21,006)	(1,214)	**(47,826)**	(43,418)	(4,408)
Cash interest	**(44,875)**	(53,946)	9,071	**(91,662)**	(107,226)	15,564
Realized financial derivatives (loss) gain	**(11,874)**	(2,257)	(9,617)	**(12,068)**	3,231	(15,299)
Realized foreign exchange gain (loss)	**(206)**	(866)	660	**197**	(2,085)	2,282
Cash other expense	**(685)**	(1,025)	340	**(1,874)**	(2,096)	222
Current income tax expense	**(4,547)**	(6,475)	1,928	**(6,699)**	(8,155)	1,456
Cash share-based compensation	**(1,555)**	(5,565)	4,010	**(2,318)**	(15,088)	12,770
Adjusted funds flow (2)	**$ 366,919**	$ 532,839	$ (165,920)	**$ 830,789**	$ 956,685	$ (125,896)
Transaction costs	**—**	—	—	**—**	(1,539)	1,539
Exploration and evaluation	**(457)**	(649)	192	**(564)**	(667)	103
Depletion and depreciation	**(322,159)**	(353,101)	30,942	**(642,082)**	(697,238)	55,156
Non-cash financing and interest	**(6,838)**	(37,671)	30,833	**(15,297)**	(45,658)	30,361
Unrealized financial derivatives gain (loss)	**30,537**	10,790	19,747	**(18,888)**	(21,560)	2,672
Unrealized foreign exchange gain (loss)	**100,792**	(19,189)	119,981	**104,267**	(57,907)	162,174
Gain (loss) on dispositions	**666**	(6,311)	6,977	**(563)**	(3,650)	3,087
Deferred income tax expense	**(17,911)**	(22,810)	4,899	**(36,522)**	(38,611)	2,089
Net income	**$ 151,549**	$ 103,898	$ 47,651	**$ 221,140**	$ 89,855	$ 131,285

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

We generated adjusted funds flow of $366.9 million for Q2/2025 and $830.8 million for YTD 2025 compared $532.8 million for Q2/2024 and $956.7 million for YTD 2024. The decrease in adjusted funds flow was primarily due to realized pricing that resulted in decreased revenues net of royalties partially offset by lower operating expense.

We reported net income of $151.5 million for Q2/2025 and $221.1 million for YTD 2025 compared to a net income of $103.9 million for Q2/2024 and $89.9 million for YTD 2024. The increase in net income for Q2/2025 and YTD 2025 is the result of lower depletion expense, non-cash financing and interest expense along with an unrealized foreign exchange gain.

OTHER COMPREHENSIVE INCOME (LOSS)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets which is not recognized in net income or loss. The foreign currency translation loss of $247.4 million for Q2/2025 and $255.9 million for YTD 2025 relates to the change in value of our U.S. net assets and is due to a strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2025 compared to March 31, 2025 and December 31, 2024. The CAD/USD exchange rate was 1.3622 CAD/USD as at June 30, 2025 compared to 1.4379 CAD/USD at March 31, 2025 and 1.4405 CAD/USD at December 31, 2024.

CAPITAL EXPENDITURES

Capital expenditures for the three and six months ended June 30, 2025 and 2024 are summarized as follows.

	Three Months Ended June 30					
	2025			2024		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 121,950**	**$ 208,592**	**$ 330,542**	$ 80,349	$ 208,662	$ 289,011
Facilities and other	**25,784**	**206**	**25,990**	21,567	28,995	50,562
Exploration and development expenditures	**$ 147,734**	**$ 208,798**	**$ 356,532**	$ 101,916	$ 237,657	$ 339,573
Property acquisitions	**$ 905**	**$ 288**	**$ 1,193**	$ 1,802	$ 1,547	$ 3,349
Proceeds from dispositions	**$ (863)**	**$ 138**	**$ (725)**	$ 157	$ (2,852)	$ (2,695)

	Six Months Ended June 30					
	2025			2024		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 289,428**	**$ 393,798**	**$ 683,226**	$ 206,357	$ 428,601	$ 634,958
Facilities and other	**42,625**	**35,778**	**78,403**	53,685	63,481	117,166
Exploration and development expenditures	**$ 332,053**	**$ 429,576**	**$ 761,629**	$ 260,042	$ 492,082	$ 752,124
Property acquisitions	**$ 1,374**	**$ 1,076**	**$ 2,450**	$ 36,077	$ 2,675	$ 38,752
Proceeds from dispositions	**$ (3,540)**	**$ 549**	**$ (2,991)**	$ 132	$ (2,852)	$ (2,720)

Exploration and development expenditures were $356.5 million for Q2/2025 and $761.6 million for YTD 2025 compared to $339.6 million for Q2/2024 and $752.1 million for YTD 2024. Exploration and development expenditures in Q2/2025 and YTD 2025 reflect our active heavy and light oil development program in Canada along with lower non-operated Eagle Ford development in the U.S.

In Canada, exploration and development expenditures were $147.7 million in Q2/2025 and $332.1 million for YTD 2025 compared to $101.9 million in Q2/2024 and $260.0 million for YTD 2024. Drilling and completion spending of $122.0 million in Q2/2025 and $289.4 million for YTD 2025 was higher than the comparative periods of 2024 which reflects increased development activity on our light and heavy oil properties.

Total U.S. exploration and development expenditures were $208.8 million for Q2/2025 and $429.6 million for YTD 2025 compared to $237.7 million in Q2/2024 and $492.1 million for YTD 2024. The decrease in exploration and development expenditures for both periods of 2025 compared to the same periods of 2024 reflects lower development activity primarily on our non-operated Eagle Ford properties coupled with realized improvements in operated drilling and completion costs per completed lateral foot.

Exploration and development expenditures of $761.6 million for YTD 2025 were consistent with expectations. We expect exploration and development expenditures for 2025 to be approximately $1.2 billion.

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain a strong balance sheet that provides financial flexibility to execute our development programs, provide returns to shareholders and optimize our portfolio through strategic acquisitions and dispositions. We strive to actively manage our capital structure in response to changes in economic conditions. At June 30, 2025, our capital structure was comprised of shareholders' capital, long-term notes, trade receivables, prepaids and other assets, trade payables, dividends payable, share-based compensation liability, other long-term liabilities, cash and the credit facilities.

In order to manage our capital structure and liquidity, we 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.

Management of debt levels is a priority for Baytex in order to sustain operations and support our business strategy. Net debt(1) of $2.3 billion at June 30, 2025 was $123.2 million lower than $2.4 billion at December 31, 2024 which was primarily due to a strengthening Canadian dollar relative to the U.S. dollar and also reflects our allocation of free cash flow to debt repayment. At current commodity prices we have adjusted our shareholder returns to allocate free cash flow to debt repayment after funding our quarterly dividend.

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

Credit Facilities

At June 30, 2025, we had $333.5 million of principal amount outstanding under our revolving credit facilities which total US$1.1 billion ($1.5 billion) (the "Credit Facilities"). The Credit Facilities are secured and are comprised of a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex and a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc.

On June 27, 2025, we extended the maturity of the Credit Facilities from May 9, 2028 to June 27, 2029. There were no changes to the loan balances or financial covenants as a result of the amendment.

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

The weighted average interest rate on the Credit Facilities was 6.5% for Q2/2025 and 6.6% for YTD 2025 compared to 7.9% for Q2/2024 and 8.0% for YTD 2024. The interest rate on our Credit Facilities has decreased with lower government benchmark rates.

At June 30, 2025, we had $5.1 million of outstanding letters of credit (December 31, 2024 - $5.8 million outstanding) under the Credit Facilities.

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

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at June 30, 2025.

Covenant Description	Position as at June 30, 2025	Covenant
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0.2:1.0**	3.5:1.0
Interest Coverage (3) (Minimum Ratio)	**10.8:1.0**	3.5:1.0
Total Debt (4) to Bank EBITDA (2) (Maximum Ratio)	**1.1:1.0**	4:0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at June 30, 2025, the Company's Senior Secured Debt totaled $337.9 million.
(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended June 30, 2025 was $2.0 billion.
(3) "Interest coverage" is calculated in accordance with the credit facility agreement and is computed as the ratio of Bank EBITDA to financing and interest expense, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Financing and interest expense for the twelve months ended June 30, 2025 was $189.2 million.
(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade payables, share-based compensation liability, dividends payable, asset retirement obligations, leases, deferred income tax liabilities, other long-term liabilities and financial derivative liabilities. As at June 30, 2025, the Company's Total Debt totaled $2.2 billion of principal amounts outstanding.

Long-Term Notes

At June 30, 2025 we have two issuances of long-term notes outstanding with a total principal amount of $1.8 billion. The long-term notes do not contain any financial maintenance covenants.

On April 27, 2023, we issued US$800 million aggregate principal amount of senior unsecured notes due April 30, 2030 bearing interest at a rate of 8.50% per annum semi-annually (the "8.50% Senior Notes"). The 8.50% Senior Notes are redeemable at our option, in whole or in part, at specified redemption prices after April 30, 2026 and will be redeemable at par from April 30, 2028 to maturity.

On April 1, 2024, we issued US$575 million aggregate principal amount of senior unsecured notes due March 15, 2032 bearing interest at a rate of 7.375% per annum payable semi-annually ("7.375% Senior Notes"). The 7.375% Senior Notes 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.

During Q2/2025, Baytex repurchased and cancelled US$40.6 million principal of the 8.50% Senior Notes for US$38.8 million ($53.7 million) and recorded a gain of $2.8 million.

Shareholders’ Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the six months ended June 30, 2025, we issued 0.1 million common shares pursuant to our share-based compensation program. As at June 30, 2025, we had 768.3 million common shares issued and outstanding and no preferred shares issued and outstanding. As at July 31, 2025, there were 768.3 million common shares issued and outstanding and no preferred shares issued and outstanding.

Our shareholder returns framework includes common share repurchases and a quarterly dividend. During the six months ended June 30, 2025, we repurchased 5.4 million common shares under our normal course issuer bid ("NCIB") at an average price of $3.12 per share for total consideration of $16.8 million. In June 2025, we renewed our NCIB under which we are permitted to purchase for cancellation up to 66.2 million common shares over the 12-month period commencing July 2, 2025, which represents 10% of Baytex's public float, as defined by the Toronto Stock Exchange, as at June 18, 2025. We have obtained an exemption order from the Canadian securities regulators which permits us to purchase its common shares through the New York Stock Exchange and other U.S.-based trading systems.

During the six months ended June 30, 2025, we recorded a $0.4 million liability related to the 2% federal tax on equity repurchases (December 31, 2024 - $4.3 million), which is charged to shareholders’ equity.

On January 2, April 1 and July 2, 2025 we paid a quarterly cash dividend of $0.0225 per share to shareholders of record. On July 31, 2025, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on October 1, 2025 to shareholders of record on September 15, 2025. These dividends are designated as “eligible dividends” for Canadian income tax purposes. These dividends are considered “qualified dividends” for U.S income tax purposes.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of June 30, 2025 and the expected timing for funding these obligations are noted in the table below.

($ thousands)	**Total**	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Credit facilities - principal	**$ 333,516**	$ —	$ —	$ 333,516	$ —
Long-term notes - principal	**1,817,707**	—	—	1,034,471	783,236
Interest on long-term notes (1)	**812,924**	145,694	291,387	276,933	98,910
Lease obligations - principal	**35,766**	15,204	12,893	6,853	816
Processing agreements	**5,445**	948	902	540	3,055
Transportation agreements	**210,633**	71,206	77,500	24,784	37,143
Total	**$ 3,215,991**	$ 233,052	$ 382,682	$ 1,677,097	$ 923,160

(1) Excludes interest on our credit facilities as interest payments fluctuate based on a floating rate of interest and changes in the outstanding balances.

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.

QUARTERLY FINANCIAL INFORMATION

	2025		2024				2023	
($ thousands, except per common share amounts)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Petroleum and natural gas sales	**886,579**	999,130	1,017,017	1,074,623	1,133,123	984,192	1,065,515	1,163,010
Net income (loss)	**151,549**	69,591	(38,477)	185,219	103,898	(14,043)	(625,830)	127,430
Per common share - basic	**0.20**	0.09	(0.05)	0.23	0.13	(0.02)	(0.75)	0.15
Per common share - diluted	**0.20**	0.09	(0.05)	0.23	0.13	(0.02)	(0.75)	0.15
Adjusted funds flow (1)	**366,919**	463,870	461,886	537,947	532,839	423,846	502,148	581,623
Per common share - basic	**0.48**	0.60	0.59	0.68	0.65	0.52	0.60	0.68
Per common share - diluted	**0.48**	0.60	0.59	0.67	0.65	0.52	0.60	0.68
Free cash flow (2)	**3,188**	52,529	254,838	220,159	180,673	(88)	290,785	158,440
Per common share - basic	**—**	0.07	0.33	0.28	0.22	—	0.35	0.19
Per common share - diluted	**—**	0.07	0.33	0.28	0.22	—	0.35	0.18
Cash flows from operating activities	**354,312**	431,317	468,865	550,042	505,584	383,773	474,452	444,033
Per common share - basic	**0.46**	0.56	0.60	0.69	0.62	0.47	0.57	0.52
Per common share - diluted	**0.46**	0.56	0.60	0.69	0.62	0.47	0.57	0.52
Dividends declared	**17,304**	17,334	17,598	17,732	18,161	18,494	18,381	19,138
Per common share	**0.0225**	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225	0.0225
Exploration and development	**356,532**	405,097	198,177	306,332	339,573	412,551	199,214	409,191
Canada	**147,734**	184,319	108,971	120,473	101,916	158,126	75,137	107,053
U.S.	**208,798**	220,778	89,206	185,859	237,657	254,425	124,077	302,138
Property acquisitions	**1,193**	1,257	12,621	1,042	3,349	35,403	33,923	4,277
Proceeds from dispositions	**(725)**	(2,266)	(42,339)	(1,436)	(2,695)	(25)	(159,745)	(226)
Net debt (1)	**2,293,940**	2,390,250	2,417,172	2,493,269	2,639,014	2,639,841	2,534,287	2,824,348
Total assets	**7,552,013**	7,824,576	7,759,745	7,614,157	7,770,926	7,717,495	7,460,931	8,946,181
Common shares outstanding	**768,317**	770,039	773,590	787,328	804,977	821,322	821,681	845,360
Daily production								
Total production (boe/d)	**148,095**	144,194	152,894	154,468	154,194	150,620	160,373	150,600
Canada (boe/d)	**64,167**	62,380	65,332	64,668	63,688	62,081	64,744	63,289
U.S. (boe/d)	**83,928**	81,814	87,562	89,800	90,506	88,540	95,629	87,311
Benchmark prices								
WTI oil (US$/bbl)	**63.74**	71.42	70.27	75.10	80.57	76.96	78.32	82.26
WCS heavy oil ($/bbl)	**74.10**	84.33	80.77	83.98	91.72	77.73	76.86	93.02
Edmonton par oil ($/bbl)	**84.15**	95.27	94.98	97.91	105.30	92.16	99.72	107.93
CAD/USD avg exchange rate	**1.3840**	1.4350	1.3992	1.3636	1.3684	1.3488	1.3619	1.3410
AECO natural gas ($/mcf)	**2.07**	2.02	1.46	0.81	1.44	2.05	2.66	2.39
NYMEX natural gas (US$/mmbtu)	**3.44**	3.65	2.79	2.16	1.89	2.24	2.88	2.55
Total sales, net of blending and other expense ($/boe) (2)	**61.16**	71.38	66.60	71.97	75.93	67.12	68.00	80.34
Royalties ($/boe) (3)	**(13.16)**	(16.02)	(14.69)	(15.75)	(17.14)	(15.26)	(15.49)	(17.33)
Operating expense ($/boe) (3)	**(11.95)**	(11.38)	(10.36)	(11.76)	(11.95)	(12.65)	(11.17)	(12.57)
Transportation expense ($/boe) (3)	**(2.44)**	(2.35)	(2.35)	(2.60)	(2.37)	(2.18)	(2.02)	(2.02)
Operating netback ($/boe) (2)	33.61	41.63	39.20	41.86	44.47	37.03	39.32	48.42
Financial derivatives (loss) gain ($/boe) (3)	**(0.88)**	(0.01)	(0.15)	0.02	(0.16)	0.40	0.84	0.15
Operating netback after financial derivatives ($/boe) (2)	32.73	41.62	39.05	41.88	44.31	37.43	40.16	48.57

(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.
(3) 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.

Over the previous eight quarters, benchmark prices for crude oil have declined following increasing supply from OPEC+ and North American production growth along with concerns over slowing global economic activity. Our realized sales price of $80.34/boe for Q3/2023 was our strongest realized pricing in the most recent eight quarters and we reported a realized price of $61.16/boe for Q2/2025.

Production has increased from 150,600 boe/d in Q3/2023 and reached a high of 160,373 boe/d in Q4/2023 which reflects active development on our properties in the U.S. and Canada. We have completed several non-core dispositions in Canada and the pace of non-operated activity in the U.S. has moderated which has resulted in production of 148,095 boe/d in Q2/2025 due to our successful development programs in Canada and the U.S. 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 $366.9 million and cash flows from operating activities of $354.3 million for Q2/2025 reflect strong production results from our development plans in the U.S. and Canada.

Net debt can fluctuate on a quarterly basis depending on changes in our free cash flow, shareholder returns and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt(1) decreased to $2.3 billion at Q2/2025 from $2.8 billion at Q3/2023 which reflects free cash flow(2) of $1.0 billion generated in the period since Q3/2023, along with $492.3 million allocated to shareholder returns in addition to a stronger Canadian dollar at Q2/2025, which decreases the reported amount of our U.S. dollar denominated debt.

(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, 2024 for a full description of the risks associated with these regulations and how they may impact our business in the future.

Reporting Regulations

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

OFF BALANCE SHEET TRANSACTIONS

We do not have any material financial arrangements that are excluded from the consolidated financial statements as at June 30, 2025, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the six months ended June 30, 2025. 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, 2024.

SPECIFIED FINANCIAL MEASURES

In this MD&A, we refer to certain specified financial measures (such as free cash flow, operating netback, total sales, net of blending and other expense, heavy oil sales, net of blending and other expense, 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 debt" 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 in the following table.

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2025**	2024	**2025**	2024
Petroleum and natural gas sales	**$ 886,579**	$ 1,133,123	**$ 1,885,709**	$ 2,117,315
Light oil and condensate (1)	**(485,922)**	(662,650)	**(1,043,884)**	(1,263,765)
NGL (1)	**(46,622)**	(49,510)	**(100,299)**	(95,441)
Natural gas (1)	**(39,781)**	(26,003)	**(88,561)**	(58,225)
Heavy oil	**$ 314,254**	$ 394,960	**$ 652,965**	$ 699,884
Blending and other expense (2)	**(62,381)**	(67,685)	**(135,201)**	(131,893)
Heavy oil, net of blending and other expense	**$ 251,873**	$ 327,275	**$ 517,764**	$ 567,991

(1) Component of petroleum and natural gas sales. See Note 12 - Petroleum and Natural Gas Sales in the consolidated financial statements for the three and six months ended June 30, 2025 for further information.
(2) The portion of blending and other expense that relates to heavy oil sales for the applicable period.

Operating netback

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

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

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2025**	2024	**2025**	2024
Petroleum and natural gas sales	**$ 886,579**	$ 1,133,123	**$ 1,885,709**	$ 2,117,315
Blending and other expense	**(62,381)**	(67,685)	**(135,201)**	(131,893)
Total sales, net of blending and other expense	**824,198**	1,065,438	**1,750,508**	1,985,422
Royalties	**(177,390)**	(240,440)	**(385,327)**	(449,611)
Operating expense	**(161,020)**	(167,705)	**(308,723)**	(341,140)
Transportation expense	**(32,907)**	(33,314)	**(63,419)**	(63,149)
Operating netback	**$ 452,881**	$ 623,979	**$ 993,039**	$ 1,131,522
Realized financial derivatives (loss) gain (1)	**(11,874)**	(2,257)	**(12,068)**	3,231
Operating netback after realized financial derivatives	**$ 441,007**	$ 621,722	**$ 980,971**	$ 1,134,753

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss. See Note 16 - Financial Instruments and Risk Management in the consolidated financial statements for the three and six months ended June 30, 2025 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 oil and gas properties, payments on lease obligations, and transaction costs.

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

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2025**	2024	**2025**	2024
Cash flows from operating activities	**$ 354,312**	$ 505,584	**$ 785,629**	$ 889,357
Change in non-cash working capital	**9,042**	20,140	**38,076**	52,163
Additions to exploration and evaluation assets	**(930)**	—	**(930)**	—
Additions to oil and gas properties	**(355,602)**	(339,573)	**(760,699)**	(752,124)
Payments on lease obligations	**(3,634)**	(5,478)	**(6,359)**	(10,350)
Transaction costs	**—**	—	**—**	1,539
Free cash flow	**$ 3,188**	$ 180,673	**$ 55,717**	$ 180,585

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 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.

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.

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). 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 and is used to assess our operating performance on a unit of production basis. Realized financial derivative gains and losses per boe are added to operating netback per boe to arrive at operating netback after financial derivatives per boe. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

Capital Management Measures

Net debt

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

The following table summarizes our calculation of net debt.

	As at	
($ thousands)	**June 30, 2025**	December 31, 2024
Credit facilities	**$ 317,310**	$ 324,346
Unamortized debt issuance costs - Credit facilities [(1)]	**16,206**	16,861
Long-term notes	**1,776,647**	1,932,890
Unamortized debt issuance costs - Long-term notes [(1)]	**41,060**	47,729
Trade payables	**538,330**	512,473
Share-based compensation liability	**13,851**	24,732
Dividends payable	**17,304**	17,598
Other long-term liabilities	**19,751**	20,887
Cash	**(7,156)**	(16,610)
Trade receivables	**(363,507)**	(387,266)
Prepaids and other assets	**(75,856)**	(76,468)
Net debt	**$ 2,293,940**	$ 2,417,172

(1) Unamortized debt issuance costs were obtained from Note 6 - Credit Facilities and Note 7 - Long-term Notes from the consolidated financial statements for the three and six months ended June 30, 2025. 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, asset retirements obligations settled during the applicable period, and transaction costs.

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

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2025**	2024	**2025**	2024
Cash flow from operating activities	**$ 354,312**	$ 505,584	**$ 785,629**	$ 889,357
Change in non-cash working capital	**9,042**	20,140	**38,076**	52,163
Asset retirement obligations settled	**3,565**	7,115	**7,084**	13,626
Transaction costs	**—**	—	**—**	1,539
Adjusted funds flow	**$ 366,919**	$ 532,839	**$ 830,789**	$ 956,685

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 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 such weaknesses were identified in, or that changes were made to, internal controls over financial reporting during the three months ended June 30, 2025.

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: we expect net debt to decline over the remainder of 2025; our 2025 guidance for: exploration and development expenditures, average daily production, royalty rate and operating expense, transportation expense, general and administrative expense, cash interest expense, current income taxes, lease expenditures and asset retirement obligations settled; the existence, operation and strategy of our risk management program; 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; our intent to fund certain 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; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; 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; that we will have sufficient financial resources in the future to 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; risks associated with a third-party operating our Eagle Ford properties; 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, 2024, 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.

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

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

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

	Notes	As at **June 30, 2025**	 December 31, 2024
ASSETS			
Current assets			
Cash	16	$ **7,156**	$ 16,610
Trade receivables	12, 16	**363,507**	387,266
Prepaids and other assets		**24,262**	20,178
Financial derivatives	16	**14,506**	25,573
		409,431	449,627
Non-current assets			
Exploration and evaluation assets	4	**126,210**	124,355
Oil and gas properties	5	**6,780,045**	6,921,168
Other plant and equipment		**7,162**	8,025
Lease assets		**28,928**	22,068
Prepaids and other assets	13	**51,594**	56,290
Deferred income tax asset	13	**148,643**	178,212
		$ **7,552,013**	$ 7,759,745
LIABILITIES			
Current liabilities			
Trade payables	16	$ **538,330**	$ 512,473
Financial derivatives	16	**8,132**	—
Share-based compensation liability	10	**10,918**	18,806
Dividends payable	9, 16	**17,304**	17,598
Lease obligations		**13,310**	9,193
Asset retirement obligations	8	**16,255**	15,656
		604,249	573,726
Non-current liabilities			
Other long-term liabilities		**19,751**	20,887
Share-based compensation liability	10	**2,933**	5,926
Financial derivatives	16	**1,334**	1,645
Credit facilities	6	**317,310**	324,346
Long-term notes	7	**1,776,647**	1,932,890
Lease obligations		**18,110**	15,459
Asset retirement obligations	8	**626,970**	625,295
Deferred income tax liability	13	**99,847**	88,561
		3,467,151	3,588,735
SHAREHOLDERS' EQUITY			
Shareholders' capital	9	**6,094,686**	6,137,479
Contributed surplus		**387,818**	361,854
Accumulated other comprehensive income		**837,395**	1,093,261
Deficit		**(3,235,037)**	(3,421,584)
		4,084,862	4,171,010
		$ **7,552,013**	$ 7,759,745

Subsequent events (notes 9, 13, and 16)

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended June 30		Six Months Ended June 30	
	Notes	**2025**	2024	**2025**	2024
Revenue, net of royalties					
Petroleum and natural gas sales	12	**$ 886,579**	$ 1,133,123	**$ 1,885,709**	$ 2,117,315
Royalties		**(177,390)**	(240,440)	**(385,327)**	(449,611)
		709,189	892,683	**1,500,382**	1,667,704
Expenses					
Operating		**161,020**	167,705	**308,723**	341,140
Transportation		**32,907**	33,314	**63,419**	63,149
Blending and other		**62,381**	67,685	**135,201**	131,893
General and administrative		**22,220**	21,006	**47,826**	43,418
Transaction costs		**—**	—	**—**	1,539
Exploration and evaluation	4	**457**	649	**564**	667
Depletion and depreciation		**322,159**	353,101	**642,082**	697,238
Share-based compensation	10	**1,555**	5,565	**2,318**	15,088
Financing and interest	14	**51,713**	91,617	**106,959**	152,884
Financial derivatives (gain) loss	16	**(18,663)**	(8,533)	**30,956**	18,329
Foreign exchange (gain) loss	15	**(100,586)**	20,055	**(104,464)**	59,992
(Gain) loss on dispositions		**(666)**	6,311	**563**	3,650
Other expense		**685**	1,025	**1,874**	2,096
		535,182	759,500	**1,236,021**	1,531,083
Net income before income taxes		**174,007**	133,183	**264,361**	136,621
Income tax expense	13				
Current income tax expense		**4,547**	6,475	**6,699**	8,155
Deferred income tax expense		**17,911**	22,810	**36,522**	38,611
		22,458	29,285	**43,221**	46,766
Net income		**$ 151,549**	$ 103,898	**$ 221,140**	$ 89,855
Other comprehensive (loss) income					
Foreign currency translation adjustment		**(247,444)**	52,019	**(255,866)**	162,582
Comprehensive (loss) income		**$ (95,895)**	$ 155,917	**$ (34,726)**	$ 252,437
Net income per common share	11				
Basic		**$ 0.20**	$ 0.13	**$ 0.29**	$ 0.11
Diluted		**$ 0.20**	$ 0.13	**$ 0.29**	$ 0.11
Weighted average common shares (000's)	11				
Basic		**768,717**	814,151	**770,072**	817,931
Diluted		**772,032**	818,025	**773,448**	821,290

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, 2023		$ 6,527,289	$ 193,077	$ 690,917	$ (3,586,196)	**$ 3,825,087**
Vesting of share awards		1,167	—	—	—	**1,167**
Repurchase of common shares for cancellation		(137,348)	53,453	—	—	**(83,895)**
Dividends declared		—	—	—	(36,655)	**(36,655)**
Comprehensive income		—	—	162,582	89,855	**252,437**
Balance at June 30, 2024		$ 6,391,108	$ 246,530	$ 853,499	$ (3,532,996)	**$ 3,958,141**
Balance at December 31, 2024		$ 6,137,479	$ 361,854	$ 1,093,261	$ (3,421,584)	**$ 4,171,010**
Vesting of share awards	9	330	—	—	—	**330**
Repurchase of common shares for cancellation	9	(43,123)	25,964	—	—	**(17,159)**
Dividends declared	9	—	—	—	(34,593)	**(34,593)**
Comprehensive (loss) income		—	—	(255,866)	221,140	**(34,726)**
Balance at June 30, 2025		$ 6,094,686	$ 387,818	$ 837,395	$ (3,235,037)	**$ 4,084,862**

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended June 30		Six Months Ended June 30	
	Notes	**2025**	2024	**2025**	2024
CASH PROVIDED BY (USED IN):					
Operating activities					
Net income		**$ 151,549**	$ 103,898	**$ 221,140**	$ 89,855
Adjustments for:					
Unrealized foreign exchange (gain) loss	15	**(100,792)**	19,189	**(104,267)**	57,907
Exploration and evaluation	4	**457**	649	**564**	667
Depletion and depreciation		**322,159**	353,101	**642,082**	697,238
Non-cash financing and interest	14	**6,838**	37,671	**15,297**	45,658
Unrealized financial derivatives (gain) loss	16	**(30,537)**	(10,790)	**18,888**	21,560
(Gain) loss on dispositions		**(666)**	6,311	**563**	3,650
Deferred income tax expense	13	**17,911**	22,810	**36,522**	38,611
Asset retirement obligations settled	8	**(3,565)**	(7,115)	**(7,084)**	(13,626)
Change in non-cash working capital		**(9,042)**	(20,140)	**(38,076)**	(52,163)
Cash flows from operating activities		**354,312**	505,584	**785,629**	889,357
Financing activities					
Increase (decrease) in credit facilities		**91,852**	(225,961)	**2,147**	(247,516)
Deferred finance costs		**(2,714)**	(25,023)	**(2,714)**	(25,023)
Payments on lease obligations		**(3,634)**	(5,478)	**(6,359)**	(10,350)
Net proceeds from issuance of long-term notes	7	**—**	780,936	**—**	780,936
Redemption of long-term notes	7	**(53,681)**	(580,913)	**(53,681)**	(580,913)
Repurchase of common shares	9	**(4,137)**	(80,890)	**(17,159)**	(83,895)
Dividends declared	9	**(17,304)**	(18,161)	**(34,593)**	(36,655)
Change in non-cash working capital		**(3,657)**	(4,105)	**(2,803)**	(2,100)
Cash flows from (used in) financing activities		**6,725**	(159,595)	**(115,162)**	(205,516)
Investing activities					
Additions to exploration and evaluation assets	4	**(930)**	—	**(930)**	—
Additions to oil and gas properties	5	**(355,602)**	(339,573)	**(760,699)**	(752,124)
Additions to other plant and equipment		**(235)**	(1,279)	**(794)**	(3,536)
Property acquisitions		**(1,193)**	(3,349)	**(2,450)**	(38,752)
Proceeds from dispositions		**725**	2,695	**2,991**	2,720
Change in non-cash working capital		**(2,612)**	2,264	**81,961**	87,923
Cash flows used in investing activities		**(359,847)**	(339,242)	**(679,921)**	(703,769)
Change in cash		**1,190**	6,747	**(9,454)**	(19,928)
Cash, beginning of period		**5,966**	29,140	**16,610**	55,815
Cash, end of period		**$ 7,156**	$ 35,887	**$ 7,156**	$ 35,887
Supplementary information					
Interest paid		**$ 53,957**	$ 86,727	**$ 90,632**	$ 105,016
Income taxes paid		**$ 14,321**	$ 11,877	**$ 19,641**	$ 16,421

See accompanying notes to the condensed consolidated interim financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the “Company” or “Baytex”) is an energy company engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and in Texas, United States. 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, 2024 ("2024 annual consolidated financial statements").

The consolidated financial statements were approved by the Board of Directors of Baytex on July 31, 2025.

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 when otherwise indicated.

The audited 2024 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.

In 2025, the U.S. government imposed tariffs on certain goods imported from other countries, including Canada. These tariffs and the Canadian government’s response to them could adversely affect market prices for crude oil and natural gas or demand for the Company’s Canadian production in addition to the cost of goods imported directly or indirectly from the U.S. The impact of these tariffs on the Company’s financial results cannot be quantified at this time.

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 accounting policies, critical accounting judgments and significant estimates used in these consolidated financial statements are consistent with those used in the preparation of the 2024 annual consolidated financial statements.

Future Accounting Pronouncements

IFRS 18 *Presentation and Disclosure in Financial Statements* was issued in April 2024 by the IASB and replaces IAS 1 *Presentation of Financial Statements*. The Standard introduces a defined structure to the statements of income or loss and comprehensive income or loss and specific disclosure requirements related to the same. The Standard is required to be adopted retrospectively and is effective for fiscal years beginning on or after January 1, 2027, with early adoption permitted. The Company is evaluating the impact that this standard will have on the consolidated financial statements.

IFRS 9 *Financial Instruments* and IFRS 7 *Financial Instruments: Disclosures* were amended in May 2024 to clarify the date of recognition and derecognition of financial assets and liabilities. The amendments are effective for fiscal years beginning on or after January 1, 2026, with early adoption permitted. The Company is evaluating the impact that this amendment will have on the consolidated financial statements.

3. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the geographic location and nature of the underlying operations:

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada;
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the Eagle Ford in Texas; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended June 30	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 411,036**	$ 508,560	**$ 475,543**	$ 624,563	**$ —**	$ —	**$ 886,579**	$ 1,133,123
Royalties	**(47,800)**	(72,894)	**(129,590)**	(167,546)	**—**	—	**(177,390)**	(240,440)
	363,236	435,666	**345,953**	457,017	**—**	—	**709,189**	892,683
Expenses								
Operating	**88,035**	84,415	**72,985**	83,290	**—**	—	**161,020**	167,705
Transportation	**20,544**	19,569	**12,363**	13,745	**—**	—	**32,907**	33,314
Blending and other	**62,381**	67,685	**—**	—	**—**	—	**62,381**	67,685
General and administrative	**—**	—	**—**	—	**22,220**	21,006	**22,220**	21,006
Exploration and evaluation	**457**	649	**—**	—	**—**	—	**457**	649
Depletion and depreciation	**115,502**	117,865	**202,685**	231,853	**3,972**	3,383	**322,159**	353,101
Share-based compensation	**—**	—	**—**	—	**1,555**	5,565	**1,555**	5,565
Financing and interest	**—**	—	**—**	—	**51,713**	91,617	**51,713**	91,617
Financial derivatives gain	**—**	—	**—**	—	**(18,663)**	(8,533)	**(18,663)**	(8,533)
Foreign exchange (gain) loss	**—**	—	**—**	—	**(100,586)**	20,055	**(100,586)**	20,055
(Gain) loss on dispositions	**(666)**	1,356	**—**	4,955	**—**	—	**(666)**	6,311
Other expense	**—**	—	**—**	—	**685**	1,025	**685**	1,025
	286,253	291,539	**288,033**	333,843	**(39,104)**	134,118	**535,182**	759,500
Net income (loss) before income taxes	**76,983**	144,127	**57,920**	123,174	**39,104**	(134,118)	**174,007**	133,183
Income tax expense								
Current income tax expense							**4,547**	6,475
Deferred income tax expense							**17,911**	22,810
							22,458	29,285
Net income							**$ 151,549**	$ 103,898
Additions to exploration and evaluation assets	**930**	—	**—**	—	**—**	—	**930**	—
Additions to oil and gas properties	**146,804**	101,916	**208,798**	237,657	**—**	—	**355,602**	339,573
Property acquisitions	**905**	1,802	**288**	1,547	**—**	—	**1,193**	3,349
Proceeds from dispositions	**(863)**	157	**138**	(2,852)	**—**	—	**(725)**	(2,695)

	Canada		U.S.		Corporate		Consolidated	
Six Months Ended June 30	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 865,187**	$ 924,873	**$ 1,020,522**	$ 1,192,442	**$ —**	$ —	**$ 1,885,709**	$ 2,117,315
Royalties	**(107,056)**	(129,458)	**(278,271)**	(320,153)	**—**	—	**(385,327)**	(449,611)
	758,131	795,415	**742,251**	872,289	**—**	—	**1,500,382**	1,667,704
Expenses								
Operating	**163,615**	169,818	**145,108**	171,322	**—**	—	**308,723**	341,140
Transportation	**39,323**	37,779	**24,096**	25,370	**—**	—	**63,419**	63,149
Blending and other	**135,201**	131,893	**—**	—	**—**	—	**135,201**	131,893
General and administrative	**—**	—	**—**	—	**47,826**	43,418	**47,826**	43,418
Transaction costs	**—**	—	**—**	—	**—**	1,539	**—**	1,539
Exploration and evaluation	**564**	667	**—**	—	**—**	—	**564**	667
Depletion and depreciation	**229,961**	234,861	**404,069**	456,292	**8,052**	6,085	**642,082**	697,238
Share-based compensation	**—**	—	**—**	—	**2,318**	15,088	**2,318**	15,088
Financing and interest	**—**	—	**—**	—	**106,959**	152,884	**106,959**	152,884
Financial derivatives loss	**—**	—	**—**	—	**30,956**	18,329	**30,956**	18,329
Foreign exchange (gain) loss	**—**	—	**—**	—	**(104,464)**	59,992	**(104,464)**	59,992
Loss (gain) on dispositions	**563**	(1,055)	**—**	4,705	**—**	—	**563**	3,650
Other expense	**—**	—	**—**	—	**1,874**	2,096	**1,874**	2,096
	569,227	573,963	**573,273**	657,689	**93,521**	299,431	**1,236,021**	1,531,083
Net income (loss) before income taxes	**188,904**	221,452	**168,978**	214,600	**(93,521)**	(299,431)	**264,361**	136,621
Income tax expense								
Current income tax expense							**6,699**	8,155
Deferred income tax expense							**36,522**	38,611
							43,221	46,766
Net income							**$ 221,140**	$ 89,855
Additions to exploration and evaluation assets	**930**	—	**—**	—	**—**	—	**930**	—
Additions to oil and gas properties	**331,123**	260,042	**429,576**	492,082	**—**	—	**760,699**	752,124
Property acquisitions	**1,374**	36,077	**1,076**	2,675	**—**	—	**2,450**	38,752
Proceeds from dispositions	**(3,540)**	132	**549**	(2,852)	**—**	—	**(2,991)**	(2,720)

	June 30, 2025	December 31, 2024
Canadian assets	**$ 2,482,098**	$ 2,381,991
U.S. assets	**5,019,319**	5,322,088
Corporate assets	**50,596**	55,666
Total consolidated assets	**$ 7,552,013**	$ 7,759,745

4. EXPLORATION AND EVALUATION ASSETS

		June 30, 2025		December 31, 2024
Balance, beginning of period	**$**	**124,355**	$	90,919
Additions to exploration and evaluation assets		**930**		—
Property acquisitions		**5,617**		39,355
Divestitures		**(1,472)**		(2,009)
Exploration and evaluation expense		**(564)**		(779)
Transfer to oil and gas properties (note 5)		**(2,656)**		(3,131)
Balance, end of period	**$**	**126,210**	$	124,355

At June 30, 2025 and December 31, 2024, 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, 2023	**$**	**15,526,017**	**$**	**(8,906,984)**	**$**	**6,619,033**
Additions to oil and gas properties		1,256,633		—		1,256,633
Property acquisitions		16,437		—		16,437
Transfers from exploration and evaluation assets (note 4)		3,131		—		3,131
Transfers from lease assets		8,210		—		8,210
Change in asset retirement obligations (note 8)		25,253		—		25,253
Divestitures		(187,103)		135,742		(51,361)
Foreign currency translation		794,766		(378,871)		415,895
Depletion		—		(1,372,063)		(1,372,063)
Balance, December 31, 2024	**$**	**17,443,344**	**$**	**(10,522,176)**	**$**	**6,921,168**
Additions to oil and gas properties		760,699		—		760,699
Property acquisitions		1,110		—		1,110
Transfers from exploration and evaluation assets (note 4)		2,656		—		2,656
Change in asset retirement obligations (note 8)		4,417		—		4,417
Divestitures		(28,946)		21,386		(7,560)
Foreign currency translation		(550,300)		281,885		(268,415)
Depletion		—		(634,030)		(634,030)
Balance, June 30, 2025	**$**	**17,632,980**	**$**	**(10,852,935)**	**$**	**6,780,045**

At June 30, 2025 and December 31, 2024, 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.

6. CREDIT FACILITIES

		June 30, 2025		December 31, 2024
Credit facilities - U.S. dollar denominated (1)	**$**	**239,057**	$	206,826
Credit facilities - Canadian dollar denominated		**94,459**		134,381
Credit facilities - principal (2)	**$**	**333,516**	$	341,207
Unamortized debt issuance costs		**(16,206)**		(16,861)
Credit facilities	**$**	**317,310**	$	324,346

(1) U.S. dollar denominated credit facilities balance was US$175.5 million as at June 30, 2025 (December 31, 2024 - US$143.6 million).
(2) The decrease in the principal amount of the credit facilities outstanding from December 31, 2024 to June 30, 2025 is the result of a decrease in the reported amount of U.S. denominated debt of $9.8 million due to foreign exchange partially offset by net draws of $2.1 million.

On June 27, 2025, Baytex extended the maturity of the revolving credit facilities (the "Credit Facilities") from May 9, 2028 to June 27, 2029. There were no changes to the loan balances or financial covenants as a result of the amendment.

At June 30, 2025, Baytex had US$1.1 billion ($1.5 billion) of revolving credit facilities that mature on June 27, 2029. The Credit Facilities are secured and are comprised of a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex and a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc.

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

Advances under the Baytex Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, Canadian Overnight Repo Rate Average rates or secured overnight financing rates ("SOFR"), plus applicable margins. Advances under the Baytex Energy USA, Inc. Credit Facilities can be drawn in U.S. funds and bear interest at the bank's prime lending rate or SOFR, plus applicable margins.

The weighted average interest rate on the Credit Facilities was 6.6% for the six months ended June 30, 2025 (8.0% for six months ended June 30, 2024).

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at June 30, 2025.

Covenant Description	**Position as at June 30, 2025**	**Covenant**
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0.2:1.0**	**3.5:1.0**
Interest Coverage (3) (Minimum Ratio)	**10.8:1.0**	**3.5:1.0**
Total Debt (4) to Bank EBITDA (2) (Maximum Ratio)	**1.1:1.0**	**4:0:1.0**

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at June 30, 2025, the Company's Senior Secured Debt totaled $337.9 million.

(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended June 30, 2025 was $2.0 billion.

(3) "Interest coverage" is calculated in accordance with the credit facility agreement and is computed as the ratio of Bank EBITDA to financing and interest expense, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Financing and interest expense for the twelve months ended June 30, 2025 was $189.2 million.

(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade payables, share-based compensation liability, dividends payable, asset retirement obligations, leases, deferred income tax liabilities, other long-term liabilities and financial derivative liabilities. As at June 30, 2025, the Company's Total Debt totaled $2.2 billion of principal amounts outstanding.

At June 30, 2025, Baytex had $5.1 million of outstanding letters of credit (December 31, 2024 - $5.8 million outstanding) under the Credit Facilities.

7. LONG-TERM NOTES

	June 30, 2025	December 31, 2024
8.50% notes due April 30, 2030 (1)	**$ 1,034,471**	$ 1,152,360
7.375% notes due March 15, 2032 (2)	**783,236**	828,259
Total long-term notes - principal (3)	**$ 1,817,707**	$ 1,980,619
Unamortized debt issuance costs	**(41,060)**	(47,729)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,776,647**	$ 1,932,890

(1) The U.S. dollar denominated principal outstanding of the 8.50% notes was US$759.4 million as at June 30, 2025 (December 31, 2024 - US$800.0 million).

(2) The U.S. dollar denominated principal outstanding of the 7.375% notes was US$575.0 million as at June 30, 2025 (December 31, 2024 - US$575.0 million).

(3) The decrease in the principal amount of long-term notes outstanding from December 31, 2024 to June 30, 2025 is the result of the repurchase and cancellation of US$40.6 million ($56.4 million) principal amount of the 8.50% notes and changes in the reported amount of U.S. denominated debt of $106.5 million due to changes in the CAD/USD exchange rate used to translate the U.S. denominated amount of long-term notes outstanding.

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

During the three months ended June 30, 2025, Baytex repurchased and cancelled US$40.6 million principal amount of the 8.50% Senior Notes at an average price of US$0.95 and recorded a gain of $2.8 million.

8. ASSET RETIREMENT OBLIGATIONS

	June 30, 2025	December 31, 2024
Balance, beginning of period	**$ 640,951**	$ 623,399
Liabilities incurred (1)	**11,562**	32,635
Liabilities settled	**(7,084)**	(28,793)
Liabilities acquired from property acquisitions	**—**	814
Liabilities divested	**(1,201)**	(9,482)
Accretion (note 14)	**11,316**	21,226
Change in estimate (1)	**2,381**	10,113
Changes in discount and inflation rates (1)(2)	**(9,526)**	(17,495)
Foreign currency translation	**(5,174)**	8,534
Balance, end of period	**$ 643,225**	$ 640,951
Less current portion of asset retirement obligations	**16,255**	15,656
Non-current portion of asset retirement obligations	**$ 626,970**	$ 625,295

(1) The total of these items reflects the total change in asset retirement obligations of $4.4 million per Note 5 - Oil and Gas Properties ($25.3 million increase in 2024).

(2) The discount and inflation rates used to calculate the liability for our Canadian operations at June 30, 2025 were 3.6% and 1.9% respectively (December 31, 2024 - 3.3% and 1.8%). The discount and inflation rates used to calculate the liability for our U.S. operations at June 30, 2025 were 4.8% and 2.3%, respectively (December 31, 2024 - 4.8% and 2.3%).

9. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at June 30, 2025, 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, 2023	**821,681**	**$**	**6,527,289**
Vesting of share awards	272		1,167
Common shares repurchased and cancelled	(48,363)		(390,977)
Balance, December 31, 2024	**773,590**	**$**	**6,137,479**
Vesting of share awards	112		330
Common shares repurchased and cancelled	(5,385)		(43,123)
Balance, June 30, 2025	**768,317**	**$**	**6,094,686**

Normal Course Issuer Bid ("NCIB") Share Repurchases

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

During the six months ended June 30, 2025, Baytex recorded $17.2 million related to common share repurchases, which includes $16.8 million of consideration paid for the repurchase and cancellation of common shares as well as $0.4 million of federal tax levied on common share repurchases.

Purchases are made on the open market at prices prevailing at the time of the transaction. During the six months ended June 30, 2025, Baytex repurchased and cancelled 5.4 million common shares at an average price of $3.12 per share for total consideration of $16.8 million. During 2024, Baytex repurchased and cancelled 48.4 million common shares at an average price of $4.50 per share for total consideration of $217.9 million. The total consideration paid includes the commissions and fees paid as part of the transaction and is recorded as a reduction to shareholders' equity. The shares repurchased and cancelled are accounted for as a reduction in shareholders' capital at historical cost with any discount paid recorded to contributed surplus and any premium paid recorded to retained earnings.

During the six months ended June 30, 2025, Baytex recorded a $0.4 million liability related to the 2% federal tax on equity repurchases (December 31, 2024 - $4.3 million), which is charged to shareholders’ equity.

Dividends

The following dividends were declared by Baytex during the six months ended June 30, 2025.

Record Date	Payable Date	Per Share Amount			Dividend Amount
March 14, 2025	April 1, 2025	$	0.0225	$	17,289
June 13, 2025	July 2, 2025		0.0225		17,304
Total dividends declared				**$**	**34,593**

On July 31, 2025, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on October 1, 2025 for shareholders of record as at September 15, 2025.

10. SHARE-BASED COMPENSATION PLAN

For the three and six months ended June 30, 2025 the Company recorded share-based compensation expense of $1.6 million and $2.3 million respectively ($5.6 million and $15.1 million for the three and six months ended June 30, 2024) which is related to cash-settled awards.

The Company's closing share price on the TSX on June 30, 2025 was $2.44 (December 31, 2024 - $3.70 and June 30, 2024 - $4.74).

Share Award Incentive Plan

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

The weighted average fair value of share awards granted during the six months ended June 30, 2025 was $2.93 per restricted and performance award ($4.28 for the six months ended June 30, 2024).

Incentive Award Plan

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

The weighted average fair value of share awards granted during the six months ended June 30, 2025 was $2.93 per incentive award ($4.28 for the six months ended June 30, 2024).

Deferred Share Unit Plan ("DSU Plan")

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

The weighted average fair value of share awards granted during the six months ended June 30, 2025 was $2.67 per DSU award ($4.48 for the six months ended June 30, 2024).

The number of awards outstanding is detailed below:

(000s)	Restricted awards	Performance awards	Incentive awards	DSU awards	Total
Total, December 31, 2023	**2,279**	**3,355**	**4,483**	**1,245**	**11,362**
Granted	13	2,416	3,671	335	6,435
Added by performance factor	—	524	—	—	524
Vested	(1,457)	(2,449)	(2,577)	(162)	(6,645)
Forfeited	(9)	(364)	(302)	—	(675)
Total, December 31, 2024	**826**	**3,482**	**5,275**	**1,418**	**11,001**
Granted	5	3,774	5,460	277	9,516
Forfeited by performance factor	—	(243)	—	—	(243)
Vested	(804)	(1,297)	(2,235)	—	(4,336)
Forfeited	(4)	(26)	(294)	—	(324)
Total, June 30, 2025	**23**	**5,690**	**8,206**	**1,695**	**15,614**

11. NET INCOME PER SHARE

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.

	Three Months Ended June 30					
	2025			2024		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	Net income	Weighted average common shares (000s)	Net income per share
Net income - basic	**$ 151,549**	**768,717**	**$ 0.20**	$ 103,898	814,151	$ 0.13
Dilutive effect of share awards	**—**	**3,315**	**—**	—	3,874	—
Net income - diluted	**$ 151,549**	**772,032**	**$ 0.20**	$ 103,898	818,025	$ 0.13

	Six Months Ended June 30					
	2025			2024		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	**Net income**	Weighted average common shares (000s)	Net income per share
Net income - basic	**$ 221,140**	**770,072**	**$ 0.29**	$ 89,855	817,931	$ 0.11
Dilutive effect of share awards	**—**	**3,376**	**—**	—	3,359	—
Net income - diluted	**$ 221,140**	**773,448**	**$ 0.29**	$ 89,855	821,290	$ 0.11

For the three and six months ended June 30, 2025 and June 30, 2024, no share awards were excluded from the calculation of diluted income per share.

12. PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas sales from contracts with customers for the Company's Canadian and U.S. operating segments is set forth in the following table.

	Three Months Ended June 30					
	2025			2024		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 83,876**	**$ 402,046**	**$ 485,922**	$ 104,030	$ 558,620	$ 662,650
Heavy oil	**314,254**	**—**	**314,254**	394,960	—	394,960
NGL	**6,232**	**40,390**	**46,622**	5,144	44,366	49,510
Natural gas	**6,674**	**33,107**	**39,781**	4,426	21,577	26,003
Total petroleum and natural gas sales	**$ 411,036**	**$ 475,543**	**$ 886,579**	$ 508,560	$ 624,563	$ 1,133,123

	Six Months Ended June 30					
	2025			2024		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 183,344**	**$ 860,540**	**$ 1,043,884**	$ 199,251	$ 1,064,514	$ 1,263,765
Heavy oil	**652,965**	**—**	**652,965**	699,884	—	699,884
NGL	**14,121**	**86,178**	**100,299**	11,513	83,928	95,441
Natural gas sales	**14,757**	**73,804**	**88,561**	14,225	44,000	58,225
Total petroleum and natural gas sales	**$ 865,187**	**$ 1,020,522**	**$ 1,885,709**	$ 924,873	$ 1,192,442	$ 2,117,315

Included in trade receivables at June 30, 2025 is $301.9 million of accrued receivables related to delivered volumes (December 31, 2024 - $325.7 million).

13. INCOME TAXES

The provision for income taxes has been computed as follows:

	Six Months Ended June 30	
	2025	2024
Net income before income taxes	**$ 264,361**	$ 136,621
Expected income taxes at the statutory rate of 24.38% (2024 – 24.64%)	**64,451**	33,663
Change in income taxes resulting from:		
Effect of foreign exchange	**(13,231)**	7,398
Effect of rate adjustments for foreign jurisdictions	**(4,093)**	(5,085)
Effect of change in deferred tax benefit not recognized [1]	**(13,826)**	2,145
Repatriation and related taxes	**7,038**	7,413
Adjustments, assessments and other	**2,882**	1,232
Income tax expense	**$ 43,221**	$ 46,766

(1) A deferred tax asset of $18.0 million remains unrecognized due to uncertainty surrounding future capital gains (December 31, 2024 - $31.8 million). The unrecognized deferred income tax asset relates to realized and unrealized foreign exchange losses arising from the repayment of previously issued U.S. dollar denominated long-term notes and from the translation of U.S. dollar denominated long-term notes currently outstanding.

On July 4, 2025, the U.S. enacted a budget reconciliation package known as the One Big Beautiful Bill Act of 2025 ("OBBBA") which includes both tax and non-tax provisions. The changes resulting from the tax provisions in OBBBA are not expected to have a material impact on the Company’s financial results.

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

We remain confident that the tax filings of the affected entities are correct and will defend our tax filing positions. During Q4/2023, 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 reassessments issued by the CRA assert taxes owing by the trusts of $244.8 million, late payment interest of $232.9 million as at the date of reassessments 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 June 2025, the Department of Justice, legal counsel for the Crown, notified Baytex that they intend to abandon 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.

14. FINANCING AND INTEREST

	Three Months Ended June 30		Six Months Ended June 30	
	2025	2024	**2025**	2024
Interest on Credit Facilities	**$ 6,855**	$ 15,639	**$ 13,038**	$ 33,928
Interest on long-term notes	**37,683**	37,656	**77,962**	72,334
Interest on lease obligations	**337**	651	**662**	964
Cash interest	**$ 44,875**	$ 53,946	**$ 91,662**	$ 107,226
Amortization of debt issue costs	**3,926**	7,862	**6,736**	10,922
Accretion on asset retirement obligations (note 8)	**5,667**	5,459	**11,316**	10,386
Gain on repurchase and cancellation of long-term notes (note 7)	**(2,755)**	—	**(2,755)**	—
Early redemption expense	**—**	24,350	**—**	24,350
Financing and interest	**$ 51,713**	$ 91,617	**$ 106,959**	$ 152,884

15. FOREIGN EXCHANGE

	Three Months Ended June 30		Six Months Ended June 30	
	2025	2024	**2025**	2024
Unrealized foreign exchange (gain) loss	**$ (100,792)**	$ 19,189	**$ (104,267)**	$ 57,907
Realized foreign exchange loss (gain)	**206**	866	**(197)**	2,085
Foreign exchange (gain) loss	**$ (100,586)**	$ 20,055	**$ (104,464)**	$ 59,992

16. 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 trade receivables and trade payables 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 based on quoted market prices. The fair value of the financial derivatives is based on quoted market prices or, in their absence, third-party market indications and forecasts.

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

	June 30, 2025		December 31, 2024		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
Fair value through profit and loss					
Financial derivatives	**$ 14,506**	**$ 14,506**	$ 25,573	$ 25,573	Level 2
Total	**$ 14,506**	**$ 14,506**	$ 25,573	$ 25,573	
Amortized cost					
Cash	**$ 7,156**	**$ 7,156**	$ 16,610	$ 16,610	—
Trade receivables	**363,507**	**363,507**	387,266	387,266	—
Total	**$ 370,663**	**$ 370,663**	$ 403,876	$ 403,876	
Financial Liabilities					
Fair value through profit and loss					
Financial derivatives	**$ (9,466)**	**$ (9,466)**	$ (1,645)	$ (1,645)	Level 2
Total	**$ (9,466)**	**$ (9,466)**	$ (1,645)	$ (1,645)	
Amortized cost					
Trade payables	**$ (538,330)**	**$ (538,330)**	$ (512,473)	$ (512,473)	—
Dividends payable	**(17,304)**	**(17,304)**	(17,598)	(17,598)	—
Credit Facilities (1)	**(317,310)**	**(333,516)**	(324,346)	(341,207)	—
Long-term notes	**(1,776,647)**	**(1,784,817)**	(1,932,890)	(1,990,598)	Level 1
Total	**$ (2,649,591)**	**$ (2,673,967)**	$ (2,787,307)	$ (2,861,876)	

(1) The difference in the carrying value and fair value of the credit facilities is due to unamortized debt issuance costs. Refer to Note 6.

There were no transfers between Level 1 and Level 2 during the six months ended June 30, 2025 and 2024.

Foreign Currency Risk

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

	Assets		Liabilities	
	June 30, 2025	December 31, 2024	**June 30, 2025**	December 31, 2024
U.S. dollar denominated	**US$14,073**	US$21,450	**US$1,361,788**	US$1,399,881

Commodity Price Risk

Financial Derivative Contracts

As at July 31, 2025, Baytex had the following commodity financial derivative contracts.

	Remaining Period	Volume	Price/Unit (1)	Index
Oil				
Basis differential	Jul 2025 to Dec 2025	21,500 bbl/d	WTI less US$13.19/bbl	WCS
Basis differential	Oct 2025 to Dec 2025	2,000 bbl/d	WTI less US$13.30/bbl	WCS
Basis differential	Aug 2025 to Sep 2025	3,500 bbl/d	WTI less US$10.55/bbl	WCS
Basis differential (3)	Jan 2026 to Mar 2026	2,500 bbl/d	WTI less US$13.35/bbl	WCS
Basis differential (3)	Apr 2026 to Jun 2026	2,500 bbl/d	WTI less US$12.55/bbl	WCS
Basis differential (3)	Jul 2026 to Sep 2026	2,500 bbl/d	WTI less US$13.05/bbl	WCS
Basis differential (3)	Jan 2026 to Dec 2026	2,500 bbl/d	WTI less US$13.35/bbl	WCS
Basis differential	Jul 2025 to Dec 2025	5,900 bbl/d	WTI less US$3.39/bbl	MSW
Basis differential (3)	Apr 2026 to Jun 2026	1,000 bbl/d	WTI less US$3.75/bbl	MSW
Put option (2)	Jan 2026 to Jun 2026	2,000 bbl/d	US$60.00	WTI
Collar	Jul 2025 to Dec 2025	4,500 bbl/d	US$60.00/US$80.00	WTI
Collar (2)	Jul 2025 to Dec 2025	27,500 bbl/d	US$60.00/US$80.00	WTI
Collar (2)	Oct 2025 to Dec 2025	3,500 bbl/d	US$60.00/US$80.00	WTI
Collar (2)	Jul 2025 to Sep 2025	8,000 bbl/d	US$60.00/US$80.00	WTI
Collar (2)(3)	Jan 2026 to Mar 2026	2,000 bbl/d	US$60.00/US$75.00	WTI
Collar (2)(3)	Jan 2026 to Mar 2026	2,000 bbl/d	US$60.00/US$75.55	WTI
Natural Gas				
Swap	Oct 2025 to Dec 2026	2,000 GJ/d	$3.21	AECO
Collar	Jul 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.01	NYMEX
Collar	Jul 2025 to Dec 2025	5,000 mmbtu/d	US$3.25/US$4.03	NYMEX
Collar	Jul 2025 to Dec 2025	5,000 mmbtu/d	US$3.25/US$4.08	NYMEX
Collar	Jul 2025 to Dec 2025	3,000 mmbtu/d	US$3.25/US$4.135	NYMEX
Collar	Jul 2025 to Dec 2025	5,500 mmbtu/d	US$3.25/US$4.14	NYMEX
Collar	Jul 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.32	NYMEX
Collar	Jul 2025 to Dec 2025	3,000 mmbtu/d	US$3.00/US$4.85	NYMEX
Collar	Jul 2025 to Dec 2025	8,000 mmbtu/d	US$3.00/US$4.855	NYMEX
Collar	Jul 2025 to Dec 2025	9,000 mmbtu/d	US$3.00/US$4.05	NYMEX
Collar	Jan 2026 to Dec 2026	10,000 mmbtu/d	US$3.25/US$4.25	NYMEX
Collar	Jan 2026 to Dec 2026	11,000 mmbtu/d	US$3.25/US$5.02	NYMEX
Collar	Jan 2026 to Dec 2026	20,000 mmbtu/d	US$4.00/US$5.10	NYMEX

(1) Based on the weighted average price per unit for the period.
(2) Contracts include deferred premiums to be paid throughout the contract term. The weighted average deferred premium is $1.05/bbl.
(3) Contract entered subsequent to June 30, 2025.

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

	Three Months Ended June 30		Six Months Ended June 30	
	2025	2024	**2025**	2024
Realized financial derivatives loss (gain)	**$ 11,874**	$ 2,257	**$ 12,068**	$ (3,231)
Unrealized financial derivatives (gain) loss	**(30,537)**	(10,790)	**18,888**	21,560
Financial derivatives (gain) loss	**$ (18,663)**	$ (8,533)	**$ 30,956**	$ 18,329

17. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain a strong balance sheet that provides financial flexibility to execute its development programs, provide returns to shareholders and optimize its portfolio through strategic acquisitions. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At June 30, 2025, the Company's capital structure was comprised of shareholders' capital, long-term notes, trade receivables, prepaids and other assets, trade payables, share-based compensation liability, dividends payable, other long-term liabilities, cash and the Credit Facilities.

In order to manage its capital structure and liquidity, Baytex may from time-to-time issue or redeem 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 Debt

The Company uses net debt to monitor its current financial position and to evaluate existing sources of liquidity. The Company defines net debt 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 and prepaids and other assets. Baytex also uses net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations.

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

	June 30, 2025	December 31, 2024
Credit Facilities	**$ 317,310**	$ 324,346
Unamortized debt issuance costs - Credit Facilities (note 6)	**16,206**	16,861
Long-term notes	**1,776,647**	1,932,890
Unamortized debt issuance costs - Long-term notes (note 7)	**41,060**	47,729
Trade payables	**538,330**	512,473
Share-based compensation liability	**13,851**	24,732
Dividends payable	**17,304**	17,598
Other long-term liabilities	**19,751**	20,887
Cash	**(7,156)**	(16,610)
Trade receivables	**(363,507)**	(387,266)
Prepaids and other assets	**(75,856)**	(76,468)
Net Debt	**$ 2,293,940**	$ 2,417,172

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, asset retirements obligations settled during the applicable period and transaction costs.

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

	Three Months Ended June 30		Six Months Ended June 30	
	2025	2024	**2025**	2024
Cash flows from operating activities	**$ 354,312**	$ 505,584	**$ 785,629**	$ 889,357
Change in non-cash working capital	**9,042**	20,140	**38,076**	52,163
Asset retirement obligations settled	**3,565**	7,115	**7,084**	13,626
Transaction costs	**—**	—	**—**	1,539
Adjusted Funds Flow	**$ 366,919**	$ 532,839	**$ 830,789**	$ 956,685