BAYTEX

Chris Lessoway

VP, Finance and Treasurer
2025-05-07

BAYTEX ANNOUNCES FIRST QUARTER 2025 RESULTS

CALGARY, ALBERTA (May 5, 2025) - Baytex Energy Corp. ("Baytex" or the "Company") (TSX:BTE) (NYSE:BTE) reports its operating and financial results for the three months ended March 31, 2025 (all amounts are in Canadian dollars unless otherwise noted).

"Baytex efficiently executed its exploration and development program and delivered first quarter results consistent with our full-year plan," said Eric T. Greager, President and Chief Executive Officer. "In a challenging operating environment marked by macroeconomic uncertainty and a volatile commodity price, we are pleased to have delivered free cash flow and returns to shareholders. As these headwinds persist, we remain focused on disciplined capital allocation and managing factors within our control to ensure financial resilience."

First Quarter 2025 Highlights

- Reported cash flows from operating activities of $431 million ($0.56 per basic share).
- Generated net income of $70 million ($0.09 per basic share).
- Delivered adjusted funds flow(1) of $464 million ($0.60 per basic share).
- Achieved production of 144,194 boe/d (84% oil and NGL), a 2% increase in production per basic share, compared to Q1/2024.
- Generated free cash flow(2) of $53 million ($0.07 per basic share) and returned $30 million to shareholders.
- Repurchased 3.7 million common shares for $13 million, at an average price of $3.49 per share.
- Paid a quarterly cash dividend of $17 million ($0.0225 per share) on April 1, 2025.
- Executed a $405 million exploration and development program, which at its peak, had 13 rigs running.
- Maintained balance sheet strength with a total debt(3) to Bank EBITDA(3) ratio of 1.0x.

2025 Outlook

Global crude oil markets remain under pressure due to broad economic uncertainty driven by concerns related to U.S. tariffs, global trade tensions, and OPEC's recent decision to increase crude oil supply. The benchmark WTI price has recently been trading in the US$55 to US$60/bbl range, down from a peak of US$80/bbl in early January.

Against this global economic backdrop, we continue to prioritize free cash flow, while taking a disciplined approach to capital allocation and our balance sheet. Our 2025 exploration and development budget is set at $1.2 to $1.3 billion and supports annual production of 148,000 to 152,000 boe/d. In light of the current commodity price environment, we anticipate full-year capital expenditures and production to trend toward the low end of these ranges.

Given these adjustments to our 2025 plan, at US$60/bbl WTI for the balance of the year, we expect to generate approximately $200 million of free cash flow this year.

In this pricing environment, we benefit from our disciplined hedging program, which helps mitigate the volatility in revenue due to changes in commodity prices. For the balance of 2025, we have hedges on approximately 45% of our net crude oil exposure using two-way collars with an average floor price of US$60/bbl.

To further strengthen our balance sheet, in the near-term we intend to allocate 100% of our free cash flow to debt repayment after funding the quarterly dividend payment. 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) Specified financial measure that does not have any standardized meaning prescribed by International Financial Reporting Standards ("IFRS") and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Ratio is calculated as total debt at March 31, 2025 divided by EBITDA for the twelve months ended March 31, 2025. Total debt and EBITDA are calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.

	Three Months Ended		
	March 31, 2025	December 31, 2024	March 31, 2024
FINANCIAL (thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales	**$ 999,130**	$ 1,017,017	$ 984,192
Adjusted funds flow [1]	**463,870**	461,886	423,846
Per share – basic	**0.60**	0.59	0.52
Per share – diluted	**0.60**	0.59	0.52
Free cash flow [2]	**52,529**	254,838	(88)
Per share – basic	**0.07**	0.33	—
Per share – diluted	**0.07**	0.33	—
Cash flows from operating activities	**431,317**	468,865	383,773
Per share – basic	**0.56**	0.60	0.47
Per share – diluted	**0.56**	0.60	0.47
Net income (loss)	**69,591**	(38,477)	(14,043)
Per share – basic	**0.09**	(0.05)	(0.02)
Per share – diluted	**0.09**	(0.05)	(0.02)
Dividends declared	**17,334**	17,598	18,494
Per share	**0.0225**	0.0225	0.0225
Capital Expenditures			
Exploration and development expenditures	**$ 405,097**	$ 198,177	$ 412,551
Acquisitions and divestitures	**(1,009)**	(29,718)	35,378
Total oil and natural gas capital expenditures	**$ 404,088**	$ 168,459	$ 447,929
Net Debt			
Credit facilities	**$ 250,284**	$ 341,207	$ 849,926
Long-term notes	**1,977,044**	1,980,619	1,637,155
Total debt [3]	**2,227,328**	2,321,826	2,487,081
Working capital deficiency [2]	**162,922**	95,346	152,760
Net debt [1]	**$ 2,390,250**	$ 2,417,172	$ 2,639,841
Shares Outstanding - basic (thousands)			
Weighted average	**771,443**	782,131	821,710
End of period	**770,039**	773,590	821,322
BENCHMARK PRICES			
Crude oil			
WTI (US$/bbl)	**$ 71.42**	$ 70.27	$ 76.96
MEH oil (US$/bbl)	**73.37**	72.40	78.95
MEH oil differential to WTI (US$/bbl)	**1.95**	2.13	1.99
Edmonton par ($/bbl)	**95.27**	94.98	92.16
Edmonton par differential to WTI (US$/bbl)	**(5.03)**	(2.39)	(8.63)
WCS heavy oil ($/bbl)	**84.33**	80.77	77.73
WCS differential to WTI (US$/bbl)	**(12.65)**	(12.54)	(19.33)
Natural gas			
NYMEX (US$/MMbtu)	**$ 3.65**	$ 2.79	$ 2.24
AECO ($/Mcf)	**2.02**	1.46	2.05
CAD/USD average exchange rate	**1.4350**	1.3992	1.3488

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		
	March 31, 2025	December 31, 2024	March 31, 2024
OPERATING			
Daily Production			
Light oil and condensate (bbl/d)	**62,335**	64,661	66,036
Heavy oil (bbl/d)	**40,192**	42,227	40,560
NGL (bbl/d)	**19,046**	21,208	19,299
Total liquids (bbl/d)	**121,573**	128,096	125,895
Natural gas (Mcf/d)	**135,731**	148,792	148,353
Oil equivalent (boe/d @ 6:1) (1)	**144,194**	152,894	150,620
Operating Netback (thousands of Canadian dollars)			
Total sales, net of blending and other expense (2)	**$ 926,310**	$ 936,869	$ 919,984
Royalties	**(207,937)**	(206,675)	(209,171)
Operating expense	**(147,703)**	(145,690)	(173,435)
Transportation expense	**(30,512)**	(33,110)	(29,835)
Operating netback (2)	**$ 540,158**	$ 551,394	$ 507,543
General and administrative expense	**(25,606)**	(20,433)	(22,412)
Cash interest	**(46,787)**	(48,769)	(53,280)
Realized financial derivatives (loss) gain	**(194)**	(2,115)	5,488
Other (3)	**(3,701)**	(18,191)	(13,493)
Adjusted funds flow (4)	**$ 463,870**	$ 461,886	$ 423,846
Operating Netback (per boe) (2)			
Total sales, net of blending and other expense (2)	**$ 71.38**	$ 66.60	$ 67.12
Royalties (5)	**(16.02)**	(14.69)	(15.26)
Operating expense (5)	**(11.38)**	(10.36)	(12.65)
Transportation expense (5)	**(2.35)**	(2.35)	(2.18)
Operating netback (2)	**$ 41.63**	$ 39.20	$ 37.03
General and administrative expense (5)	**(1.97)**	(1.45)	(1.64)
Cash interest (5)	**(3.61)**	(3.47)	(3.89)
Realized financial derivatives (loss) gain (5)	**(0.01)**	(0.15)	0.40
Other (3)(5)	**(0.30)**	(1.29)	(0.98)
Adjusted funds flow (4)	**$ 35.74**	$ 32.84	$ 30.92

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 or recovery and cash share-based compensation. Refer to the Q1/2025 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.

Q1/2025 Results

During the first quarter, we delivered operating and financial results consistent with our full-year plan despite periods of extremely cold temperatures across North America, which resulted in modest production disruptions across our operations.

We increased production per basic share by 2% in Q1/2025, compared to Q1/2024, with production averaging 144,194 boe/d (84% oil and NGL). As compared to Q1/2024, production during the first quarter was lower, in part, due to weather disruptions (approximately 2,000 boe/d) and our Kerrobert thermal disposition (approximately 2,000 boe/d). Exploration and development expenditures totaled $405 million, consistent with our full-year plan, and we brought 105 (95.9 net) wells onstream.

Adjusted funds flow(1) was $464 million or $0.60 per basic share and we generated net income of $70 million ($0.09 per basic share).

During the first quarter we generated free cash flow(2) of $53 million ($0.07 per basic share) and returned $30 million to shareholders. We repurchased 3.7 million common shares for $13 million, at an average price of $3.49 per share, and paid a quarterly cash dividend of $17 million ($0.0225 per share).

Over the last seven quarters, we returned $580 million to shareholders. We repurchased 92.6 million common shares for $453 million, representing approximately 11% of our shares outstanding, at an average price of $4.89 per share, and paid total dividends of $127 million ($0.1575 per share).

As of March 31, 2025, our net debt(1) was $2.4 billion, a reduction of approximately 10% ($250 million) over the past twelve months. On a U.S. dollar basis, net debt decreased by approximately 15% (US$287 million). We maintain strong financial flexibility, supported by significant credit capacity and a long-term notes maturity schedule that positions us well throughout various commodity price cycles. Our credit facilities have total capacity of US$1.1 billion, mature on May 9, 2028, and are less than 20% drawn. These are not borrowing base facilities and do not require annual or semi-annual reviews. Additionally, our earliest note maturity (US$800 million) is not until April 30, 2030.

Strengthening our balance sheet remains a key priority. Our pace of debt repayment reflects free cash flow generation and the impact of CAD/USD exchange rate fluctuations, which affect the conversion of our U.S. dollar-denominated debt. A $0.05 CAD/USD change in the exchange rate impacts our net debt by approximately $70 million.

Operations

In the Eagle Ford, production averaged 81,814 boe/d (81% oil and NGL) in Q1/2025 and we brought onstream 15.6 net wells, including 12.4 net operated wells. Our development program was largely focused on the black oil to condensate windows of our acreage where we typically generate 30-day peak crude oil rates of 700 to 800 bbl/d (900 to 1,100 boe/d) per well with average lateral lengths of 9,000 to 9,500 feet. We expect to bring onstream 50 net wells in 2025 and are targeting a 7% improvement in operated drilling and completion costs per completed lateral foot compared to 2024.

In our Canadian light oil business, production averaged 16,685 boe/d (83% oil and NGL) in Q1/2025. In the Pembina Duvernay, two of three pads have been drilled (six wells), including our longest wells in the play at more than 24,000 feet total measured depth and 13,500 feet of lateral length. Completion operations commenced mid-April and we expect to onstream the wells during the second and third quarter. In the Viking, 42 net wells were brought onstream in Q1/2025. In 2025, we expect to bring onstream nine net wells in the Pembina Duvernay and 85 net wells in the Viking.

In our heavy oil business, production averaged 41,119 boe/d (96% oil and NGL) in Q1/2025. Peavine continued to deliver top well results with production averaging 17,714 boe/d (100% heavy oil) during the first quarter. We brought onstream 12 net Clearwater wells at Peavine, 4 net wells at Peace River and 12 net wells across the broader Mannville group in Lloydminster. In 2025, we expect to bring onstream 112 net heavy oil wells, including 33 net Clearwater wells at Peavine.

Quarterly Dividend

The Board of Directors has declared a quarterly cash dividend of $0.0225 per share, to be paid on July 2, 2025 to shareholders of record on June 13, 2025.

(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.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three months ended March 31, 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, May 6, 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=MHer58bF 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 and managing factors within our control; we are committed to prioritizing free cash flow, and a disciplined approach to capital allocation and our balance sheet; for 2025: our guidance for exploration and development expenditures and production and our expectation that capital expenditures and production will trend toward the low end of these guidance ranges; the amount of free cash flow we expect to generate; our expected allocation of free cash flow as between the balance sheet and shareholder returns (including dividends and share buybacks); the expected impact of changes to the CAD/US exchange rate on our debt; and our expected wells on-stream by asset. 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.*

The future acquisition of our common shares pursuant to a share buyback (including through its Normal Course Issuer Bid), 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) or 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. 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		
($ thousands)	**March 31, 2025**	December 31, 2024	March 31, 2024
Petroleum and natural gas sales	**$ 999,130**	$ 1,017,017	$ 984,192
Blending and other expense	**(72,820)**	(80,148)	(64,208)
Total sales, net of blending and other expense	**$ 926,310**	$ 936,869	$ 919,984
Royalties	**(207,937)**	(206,675)	(209,171)
Operating expense	**(147,703)**	(145,690)	(173,435)
Transportation expense	**(30,512)**	(33,110)	(29,835)
Operating netback	**$ 540,158**	$ 551,394	$ 507,543
Realized financial derivatives (loss) gain [1]	**(194)**	(2,115)	5,488
Operating netback after realized financial derivatives	**$ 539,964**	$ 549,279	$ 513,031

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss. See the Financial Instruments and Risk Management note in the consolidated financial statements for the three months ended March 31, 2025 and the consolidated financial statements for the year ended December 31, 2024 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		
($ thousands)	**March 31, 2025**	December 31, 2024	March 31, 2024
Cash flows from operating activities	**$ 431,317**	$ 468,865	$ 383,773
Change in non-cash working capital	**29,034**	(13,428)	32,023
Additions to oil and gas properties	**(405,097)**	(198,177)	(412,551)
Payments on lease obligations	**(2,725)**	(2,422)	(4,872)
Transaction costs	**—**	—	1,539
Free cash flow	**$ 52,529**	$ 254,838	$ (88)

Working capital deficiency

Working capital deficiency is calculated as cash, trade receivables, prepaids and other assets net of trade payables, dividends payable, other long-term liabilities and share-based compensation liability. Working capital deficiency is used by management to measure the Company's liquidity. At March 31, 2025, the Company had $1.3 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)	**March 31, 2025**	December 31, 2024	March 31, 2024
Cash	**$ (5,966)**	$ (16,610)	$ (29,140)
Trade receivables	**(391,905)**	(387,266)	(423,119)
Prepaids and other assets	**(72,045)**	(76,468)	(77,901)
Trade payables	**582,053**	512,473	626,137
Share-based compensation liability	**12,602**	24,732	18,667
Dividends payable	**17,334**	17,598	18,494
Other long-term liabilities	**20,849**	20,887	19,622
Working capital deficiency	**$ 162,922**	$ 95,346	$ 152,760

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)	**March 31, 2025**	December 31, 2024	March 31, 2024
Credit facilities	**$ 234,683**	$ 324,346	$ 835,363
Unamortized debt issuance costs - Credit facilities [(1)]	**15,601**	16,861	14,563
Long-term notes	**1,930,809**	1,932,890	1,602,417
Unamortized debt issuance costs - Long-term notes [(1)]	**46,235**	47,729	34,738
Trade payables	**582,053**	512,473	626,137
Share-based compensation liability	**12,602**	24,732	18,667
Dividends payable	**17,334**	17,598	18,494
Other long-term liabilities	**20,849**	20,887	19,622
Cash	**(5,966)**	(16,610)	(29,140)
Trade receivables	**(391,905)**	(387,266)	(423,119)
Prepaids and other assets	**(72,045)**	(76,468)	(77,901)
Net debt	**$ 2,390,250**	$ 2,417,172	$ 2,639,841

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

Adjusted funds flow

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

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

	Three Months Ended		
($ thousands)	**March 31, 2025**	December 31, 2024	March 31, 2024
Cash flow from operating activities	**$ 431,317**	$ 468,865	$ 383,773
Change in non-cash working capital	**29,034**	(13,428)	32,023
Asset retirement obligations settled	**3,519**	6,449	6,511
Transaction costs	**—**	—	1,539
Adjusted funds flow	**$ 463,870**	$ 461,886	$ 423,846

Advisory Regarding Oil and Gas Information

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

References herein to average 30-day 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 months ended March 31, 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 March 31, 2025					Three Months Ended March 31, 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	10,212	11	18	9,622	11,845	9,481	9	48	10,088	11,219
Lloydminster	11,349	13	—	1,190	11,560	13,156	12	—	1,431	13,407
Peavine	17,714	—	—	—	17,714	17,599	—	—	—	17,599
Canada - Light										
Viking	111	8,959	153	10,318	10,943	—	9,181	190	11,068	11,215
Duvernay	—	2,404	2,221	6,704	5,742	—	1,803	1,757	5,456	4,469
Remaining Properties	806	388	731	15,909	4,576	324	488	636	16,337	4,171
United States										
Eagle Ford	—	50,560	15,923	91,988	81,814	—	54,543	16,668	103,973	88,540
Total	40,192	62,335	19,046	135,731	144,194	40,560	66,036	19,299	148,353	150,620

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

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

BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three months ended March 31, 2025 and 2024
Dated May 5, 2025

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three months ended March 31, 2025. This information is provided as of May 5, 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 months ended March 31, 2025 ("Q1/2025") have been compared with the results for the three months ended March 31, 2024 ("Q1/2024"). This MD&A should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements ("consolidated financial statements") for the three months ended March 31, 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.

FIRST QUARTER HIGHLIGHTS

Baytex delivered strong operating and financial results in Q1/2025. Production of 144,194 boe/d and exploration and development expenditures of $405.1 million for Q1/2025 were consistent with our full-year plan and reflect our successful development programs in the U.S. and Canada. We generated free cash flow(1) of $52.5 million and returned $30.1 million to shareholders.

We spent $405.1 million on exploration and development expenditures in Q1/2025, similar to $412.6 million in Q1/2024 and consistent with our full year plans to spend at the low end of our annual guidance range of $1.2 - 1.3 billion. In the U.S., we invested $220.8 million and production averaged 81,814 boe/d during Q1/2025 compared to exploration and development expenditures of $254.4 million and production of 88,540 boe/d for Q1/2024. In Canada, we invested $184.3 million and generated production of 62,380 boe/d in Q1/2025 compared to exploration and development expenditures of $158.1 million and production of 62,081 boe/d in Q1/2024.

Oil prices began to decline late in Q1/2025 as a result of weaker demand, higher supply and global economic concerns. The WTI benchmark price for Q1/2025 was US$71.42/bbl which was lower than Q1/2024 when WTI averaged US$76.96/bbl. Strong realized pricing due to narrower Canadian oil differentials, higher U.S. gas pricing, improved NGL realizations and a weaker Canadian dollar resulted in adjusted funds flow(2) of $463.9 million and cash flows from operating activities of $431.3 million for Q1/2025 compared to Q1/2024 when we generated adjusted funds flow of $423.8 million and cash flows from operating activities of $383.8 million.

(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.

Net debt[1] of $2.4 billion at March 31, 2025 was $26.9 million lower than at December 31, 2024 which reflects our allocation of free cash flow to debt repayment in Q1/2025. Free cash flow[2] of $52.5 million generated in Q1/2025 was allocated to debt repayment along with $30.1 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

The following table compares our 2025 annual guidance to our Q1/2025 results. We delivered operating and financial results that were consistent with our annual plan. Our 2025 guidance range for exploration and development expenditures is $1.2 - $1.3 billion and supports annual production of 148,000 - 152,000 boe/d. In light of the current commodity price environment, we anticipate 2025 exploration and development expenditures and production to trend toward the low end of these ranges.

	2025 Annual Guidance [1]	Q1/2025 Results
Exploration and development expenditures	$1.2 - $1.3 billion	$405.1 million
Production (boe/d)	148,000 - 152,000 [2]	144,194
Expenses:		
Average royalty rate [3]	~ 23%	22.4 %
Operating [4]	$11.75 - $12.50/boe	$11.38/boe
Transportation [4]	$2.40 - $2.55/boe	$2.35/boe
General and administrative [4]	$90 million ($1.67/boe) [5]	$25.6 million ($1.97/boe)
Cash interest [4]	$180 million ($3.33/boe) [5]	$46.8 million ($3.61/boe)
Current income tax	~ 1% of EBITDA [6]	0.4% of EBITDA [6]
Leasing expenditures	$10 million	$2.7 million
Asset retirement obligations	$25 million	$3.5 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 March 31					
	2025			2024		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**11,775**	**50,560**	**62,335**	11,493	54,543	66,036
Heavy oil	**40,192**	**—**	**40,192**	40,560	—	40,560
Natural Gas Liquids (NGL)	**3,123**	**15,923**	**19,046**	2,631	16,668	19,299
Total liquids (bbl/d)	**55,090**	**66,483**	**121,573**	54,684	71,211	125,895
Natural gas (mcf/d)	**43,743**	**91,988**	**135,731**	44,380	103,973	148,353
Total production (boe/d)	**62,380**	**81,814**	**144,194**	62,081	88,540	150,620
Production Mix						
Segment as a percent of total	**43 %**	**57 %**	**100 %**	41 %	59 %	100 %
Light oil and condensate	**19 %**	**62 %**	**43 %**	19 %	62 %	44 %
Heavy oil	**64 %**	**— %**	**28 %**	65 %	— %	27 %
NGL	**5 %**	**19 %**	**13 %**	4 %	19 %	13 %
Natural gas	**12 %**	**19 %**	**16 %**	12 %	19 %	16 %

Production of 144,194 boe/d for Q1/2025 is consistent with expectations and was lower than 150,620 boe/d for Q1/2024 which reflects lower development on our non-operated Eagle Ford assets, severe winter weather in the U.S. and the disposition of non-core heavy oil assets in Q4/2024.

In Canada, production was 62,380 boe/d for Q1/2025 compared to 62,081 boe/d for Q1/2024. Our successful light and heavy oil development programs resulted in a 299 boe/d increase in production for Q1/2025 compared to Q1/2024 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 81,814 boe/d for Q1/2025 compared to 88,540 boe/d in Q1/2024. Production in the U.S. was lower during Q1/2025 which reflects reduced non-operated Eagle Ford activity in late 2024 and early 2025. Severe winter weather during Q1/2025 temporarily disrupted our operations and impacted production by approximately 2,000 boe/d for the period. We initiated production from 27 (15.6 net) wells during Q1/2025 compared to 37 (22.4 net) wells during Q1/2024.

Total production of 144,194 boe/d for YTD 2025 is consistent with expectations. We are expecting production to be at the low end of our annual guidance range of 148,000 - 152,000 boe/d for 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 Q1/2025, global benchmark pricing for crude oil was volatile as a result of geopolitical events and concerns over slowing global economic activity. Crude oil prices were lower in Q1/2025 relative to Q1/2024 as a result of increased supply from OPEC+ along with North American production growth. The WTI benchmark price averaged US$71.42/bbl for Q1/2025 compared to US$76.96/bbl for Q1/2024.

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$73.37/bbl during Q1/2025 compared to US$78.95/bbl for Q1/2024 and typically trades at a premium to WTI as a result of access to global markets. The MEH benchmark premium to WTI was US$1.95/bbl for Q1/2025 which was consistent with a premium of US$1.99/bbl for Q1/2024.

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 Q1/2025 relative to Q1/2024 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 $95.27/bbl during Q1/2025 compared to $92.16/bbl during Q1/2024. Edmonton par traded at a discount to WTI of US$5.03/bbl for Q1/2025 compared to a discount of US$8.63/bbl for Q1/2024.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS benchmark for Q1/2025 averaged $84.33/bbl compared to $77.73/bbl for the same period of 2024. The WCS heavy oil differential to WTI was US$12.65/bbl in Q1/2025 compared to US$19.33/bbl for Q1/2024.

Natural Gas

Natural gas prices in Canada and the U.S. for Q1/2025 reflect incremental demand from cold winter weather and additional supply from production growth in Canada.

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$3.65/mmbtu for Q1/2025 compared to US$2.24/mmbtu for Q1/2024.

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 $2.02/mcf during Q1/2025, consistent with $2.05/mcf for Q1/2024.

The following tables compare select benchmark prices and our average realized selling prices for the three months ended March 31, 2025 and 2024.

	Three Months Ended March 31		
	2025	2024	Change
Benchmark Averages			
WTI oil (US$/bbl) (1)	**71.42**	76.96	(5.54)
MEH oil (US$/bbl) (2)	**73.37**	78.95	(5.58)
MEH oil differential to WTI (US$/bbl)	**1.95**	1.99	(0.04)
Edmonton par oil ($/bbl) (3)	**95.27**	92.16	3.11
Edmonton par oil differential to WTI (US$/bbl)	**(5.03)**	(8.63)	3.60
WCS heavy oil ($/bbl) (4)	**84.33**	77.73	6.60
WCS heavy oil differential to WTI (US$/bbl)	**(12.65)**	(19.33)	6.68
AECO natural gas ($/mcf) (5)	**2.02**	2.05	(0.03)
NYMEX natural gas (US$/mmbtu) (6)	**3.65**	2.24	1.41
CAD/USD average exchange rate	**1.4350**	1.3488	0.0862

(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 March 31					
	2025			2024		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) (1)	**$ 93.86**	**$ 100.76**	**$ 99.46**	$ 91.05	$ 101.93	$ 100.03
Heavy oil, net of blending and other expense ($/bbl) (2)	**73.51**	**—**	**73.51**	65.22	—	65.22
NGL ($/bbl) (1)	**28.07**	**31.95**	**31.31**	26.60	26.08	26.15
Natural gas ($/mcf) (1)	**2.05**	**4.92**	**3.99**	2.42	2.37	2.39
Total sales, net of blending and other expense ($/boe) (2)	**$ 67.92**	**$ 74.01**	**$ 71.38**	$ 62.33	$ 70.48	$ 67.12

(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 $71.38/boe for Q1/2025 compared to $67.12/boe for Q1/2024. Our average realized sales price increased despite lower WTI due to narrower Canadian oil differentials, higher natural gas prices and improved NGL realizations in the U.S., along with a weaker Canadian dollar relative to Q1/2024.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price represents a discount to the Edmonton par price of $1.41/bbl for Q1/2025 consistent with a discount of $1.11/bbl in Q1/2024.

The price received for our U.S. light oil and condensate production is based on the MEH benchmark. Our realized light oil and condensate price averaged $100.76/bbl for Q1/2025 compared to $101.93/bbl for Q1/2024. Expressed in U.S. dollars, our realized light oil and condensate price for Q1/2025 represents a discount to MEH of US$3.15/bbl for Q1/2025 compared to a discount of US$3.38/bbl for Q1/2024.

Our realized heavy oil price, net of blending and other expense for Q1/2025 increased by $8.29/bbl from Q1/2024, compared to a $6.60/bbl increase in the WCS benchmark price over the same period. Our realized price increased more than the benchmark price as the cost of condensate purchased for blending was lower relative to the price received for sales of the blended product based on the WCS benchmark in Q1/2025 compared to Q1/2024.

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. Our realized NGL price[2] was $31.31/bbl in Q1/2025 or 31% of WTI (expressed in Canadian dollars) which reflects strong ethane pricing compared to Q1/2024 when our realized NGL price was $26.15/bbl or 25% of WTI (expressed in Canadian dollars).

We compare our realized natural gas price in the U.S. to the NYMEX benchmark and to the AECO benchmark price in Canada. The change in our realized natural gas prices in Canada and the U.S. for Q1/2025 is consistent with the change in the AECO and NYMEX benchmark prices relative to Q1/2024.

(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 March 31					
	2025			2024		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 99,469**	**$ 458,495**	**$ 557,964**	$ 95,221	$ 505,894	$ 601,115
Heavy oil	**338,711**	**—**	**338,711**	304,924	—	304,924
NGL	**7,888**	**45,788**	**53,676**	6,368	39,562	45,930
Total oil sales	**446,068**	**504,283**	**950,351**	406,513	545,456	951,969
Natural gas sales	**8,083**	**40,696**	**48,779**	9,800	22,423	32,223
Total petroleum and natural gas sales	**454,151**	**544,979**	**999,130**	416,313	567,879	984,192
Blending and other expense	**(72,820)**	**—**	**(72,820)**	(64,208)	—	(64,208)
Total sales, net of blending and other expense [(1)]	**$ 381,331**	**$ 544,979**	**$ 926,310**	$ 352,105	$ 567,879	$ 919,984

(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 $926.3 million for Q1/2025 which reflects higher realized pricing compared to Q1/2024 when total sales, net of blending and other expense, was $920.0 million. The increase in total sales, net of blending and other expense reflects higher realized pricing which more than offset the impact of lower production in Q1/2025 relative to Q1/2024.

In Canada, total sales, net of blending and other expense, of $381.3 million for Q1/2025 increased from $352.1 million reported for Q1/2024 due to an increase in our realized pricing.

In the U.S., total petroleum and natural gas sales of $545.0 million for Q1/2025 decreased from $567.9 million reported for Q1/2024. Higher realized pricing resulted in a $26.0 million increase in total sales in Q1/2025 relative to Q1/2024 while lower production contributed to a $48.9 million decrease in total sales relative to Q1/2024.

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 months ended March 31, 2025 and 2024.

	Three Months Ended March 31					
	2025			2024		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 59,256**	**$ 148,681**	**$ 207,937**	$ 56,564	$ 152,607	$ 209,171
Average royalty rate [(1)(2)]	**15.5 %**	**27.3 %**	**22.4 %**	16.1 %	26.9 %	22.7 %
Royalties per boe [(3)]	**$ 10.55**	**$ 20.19**	**$ 16.02**	$ 10.01	$ 18.94	$ 15.26

(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 Q1/2025 were $207.9 million or 22.4% of total sales, net of blending and other expense, compared to $209.2 million or 22.7% for Q1/2024.

Our average royalty rate in Canada of 15.5% for Q1/2025 was consistent with 16.1% for Q1/2024. In the U.S., our average royalty rate was 27.3% for Q1/2025 which was consistent with 26.9% for Q1/2024.

Our average royalty rate of 22.4% for YTD 2025 is consistent with our annual guidance of 23.0% for 2025.

OPERATING EXPENSE

	Three Months Ended March 31					
	2025			2024		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 75,580**	**$ 72,123**	**$ 147,703**	$ 85,403	$ 88,032	$ 173,435
Operating expense per boe [1]	**$ 13.46**	**$ 9.79**	**$ 11.38**	$ 15.12	$ 10.93	$ 12.65

(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 $147.7 million ($11.38/boe) for Q1/2025 which is lower than $173.4 million ($12.65/boe) for Q1/2024, and reflects production growth at Peavine along with the disposition of non-core Kerrobert Thermal assets in Q4/2024.

In Canada, total operating expense was $75.6 million ($13.46/boe) for Q1/2025 which was lower than $85.4 million ($15.12/boe) for Q1/2024. The decrease in total and per unit operating expense relative to 2024 is due to lower carbon tax compliance costs along with the disposition of higher cost non-core assets in Q4/2024.

In the U.S., operating expense was $72.1 million ($9.79/boe) for Q1/2025 which was lower than $88.0 million ($10.93/boe) for Q1/2024. Per boe operating expense in the U.S., expressed in U.S. dollars, was US$6.82/boe for Q1/2025 which was lower than US$8.10/boe for Q1/2024. The decrease in total and per unit operating expense reflects our cost savings initiatives and lower production in Q1/2025 compared to Q1/2024.

Operating expense of $11.38/boe for YTD 2025 is consistent with expectations and 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 months ended March 31, 2025 and 2024.

	Three Months Ended March 31					
	2025			2024		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 18,779**	**$ 11,733**	**$ 30,512**	$ 18,210	$ 11,625	$ 29,835
Transportation expense per boe [1]	**$ 3.34**	**$ 1.59**	**$ 2.35**	$ 3.22	$ 1.44	$ 2.18

(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 $30.5 million ($2.35/boe) for Q1/2025 compared to $29.8 million ($2.18/boe) for Q1/2024. Total and per unit transportation expense for Q1/2025 in Canada and the U.S. was consistent with Q1/2024.

Per unit transportation expense of $2.35/boe for Q1/2025 is consistent with expectations and is slightly below 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 $72.8 million for Q1/2025 compared to $64.2 million for Q1/2024. Higher blending and other expense reflects a change in contractual arrangements for 2025 which resulted in higher blending and other expense.

FINANCIAL DERIVATIVES

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates, interest rates and changes in our share price. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our free cash flow. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the three months ended March 31, 2025 and 2024.

	Three Months Ended March 31		
($ thousands)	**2025**	2024	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ (834)**	$ 946	$ (1,780)
Natural gas	**640**	4,542	(3,902)
Total	**$ (194)**	$ 5,488	$ (5,682)
Unrealized financial derivatives gain (loss)			
Crude oil	**$ (34,041)**	$ (31,465)	$ (2,576)
Natural gas	**(15,384)**	(885)	(14,499)
Total	**$ (49,425)**	$ (32,350)	$ (17,075)
Total financial derivatives gain (loss)			
Crude oil	**$ (34,875)**	$ (30,519)	$ (4,356)
Natural gas	**(14,744)**	3,657	(18,401)
Total	**$ (49,619)**	$ (26,862)	$ (22,757)

We recorded total financial derivatives losses of $49.6 million for Q1/2025 compared to losses of $26.9 million for Q1/2024. The realized financial derivatives loss of $0.2 million for Q1/2025 resulted from gains of $0.6 million on natural gas contracts and losses of $0.8 million on crude oil contracts. The unrealized financial derivatives loss of $49.4 million for Q1/2025 resulted from a $34.0 million loss on crude oil contracts and a $15.4 million loss on natural gas contracts. The fair value of our financial derivative contracts resulted in a net liability of $25.5 million at March 31, 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 May 5, 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 months ended March 31, 2025 and 2024.

	Three Months Ended March 31					
	2025			2024		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**62,380**	**81,814**	**144,194**	62,081	88,540	150,620
Operating netback:						
Total sales, net of blending and other expense [1]	**$ 67.92**	**$ 74.01**	**$ 71.38**	$ 62.33	$ 70.48	$ 67.12
Less:						
Royalties [2]	**(10.55)**	**(20.19)**	**(16.02)**	(10.01)	(18.94)	(15.26)
Operating expense [2]	**(13.46)**	**(9.79)**	**(11.38)**	(15.12)	(10.93)	(12.65)
Transportation expense [2]	**(3.34)**	**(1.59)**	**(2.35)**	(3.22)	(1.44)	(2.18)
Operating netback [1]	**$ 40.57**	**$ 42.44**	**$ 41.63**	$ 33.98	$ 39.17	$ 37.03
Realized financial derivatives gain (loss) [3]	**—**	**—**	**(0.01)**	—	—	0.40
Operating netback after financial derivatives [1]	**$ 40.57**	**$ 42.44**	**$ 41.62**	$ 33.98	$ 39.17	$ 37.43

(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 $41.63/boe for Q1/2025 was higher than $37.03/boe for Q1/2024 due to the increase in our realized price which resulted in higher per unit sales net of royalties. Total operating expense of $11.38/boe for Q1/2025 was lower than $12.65/boe for Q1/2024 which reflects lower activity levels and cost savings on our U.S. properties. Our operating netback net of realized gains and losses on financial derivatives was $41.62/boe for Q1/2025 compared to $37.43/boe for Q1/2024.

GENERAL AND ADMINISTRATIVE EXPENSE

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

The following table summarizes our G&A expense for the three months ended March 31, 2025 and 2024.

	Three Months Ended March 31		
($ thousands except for per boe)	**2025**	2024	Change
Gross general and administrative expense	**$ 32,662**	$ 28,763	$ 3,899
Overhead recoveries	**(7,056)**	(6,351)	(705)
General and administrative expense	**$ 25,606**	$ 22,412	$ 3,194
General and administrative expense per boe [1]	**$ 1.97**	$ 1.64	$ 0.33

(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 $25.6 million ($1.97/boe) for Q1/2025 compared to $22.4 million ($1.64/boe) for Q1/2024 which reflects the timing of certain costs. G&A expense of $25.6 million ($1.97/boe) for Q1/2025 is consistent with expectations and is higher than our 2025 annual guidance of approximately $90.0 million ($1.67/boe) which reflects timing 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 months ended March 31, 2025 and 2024.

	Three Months Ended March 31		
($ thousands except for per boe)	**2025**	2024	Change
Interest on credit facilities	**$ 6,183**	$ 18,289	$ (12,106)
Interest on long-term notes	**40,279**	34,678	5,601
Interest on lease obligations	**325**	313	12
Cash interest	**$ 46,787**	$ 53,280	$ (6,493)
Accretion of debt issue costs	**2,810**	3,060	(250)
Accretion of asset retirement obligations	**5,649**	4,927	722
Financing and interest expense	**$ 55,246**	$ 61,267	$ (6,021)
Cash interest per boe (1)	**$ 3.61**	$ 3.89	$ (0.28)
Financing and interest expense per boe (1)	**$ 4.26**	$ 4.47	$ (0.21)

(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 $55.2 million ($4.26/boe) for Q1/2025 compared to $61.3 million ($4.47/boe) for Q1/2024. The decrease in interest costs in Q1/2025 is due to lower outstanding debt balances compared to Q1/2024.

Cash interest of $46.8 million ($3.61/boe) for Q1/2025 was lower than $53.3 million ($3.89/boe) for Q1/2024. Lower interest on our credit facilities reflects lower debt balances outstanding in Q1/2025, 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 6.9% for Q1/2025 compared to 7.8% for Q1/2024.

Accretion of asset retirement obligations of $5.6 million for Q1/2025 was higher than $4.9 million for Q1/2024 due to a higher asset retirement obligation liability at Q1/2025. Accretion of debt issue costs of $2.8 million for Q1/2025 was consistent with $3.1 million for Q1/2024.

Cash interest expense of $46.8 million ($3.61/boe) for Q1/2025 is higher than our 2025 annual guidance of $180 million ($3.33/boe) which is consistent with expectations as we expect to reduce debt and our expectations for production 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 $107.0 thousand for Q1/2025 compared to $18.0 thousand for Q1/2024.

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 months ended March 31, 2025 and 2024.

	Three Months Ended March 31		
($ thousands except for per boe)	**2025**	2024	Change
Depletion	**$ 315,843**	$ 341,435	$ (25,592)
Depreciation	**4,080**	2,702	1,378
Depletion and depreciation	**$ 319,923**	$ 344,137	$ (24,214)
Depletion and depreciation per boe (1)	**$ 24.65**	$ 25.11	$ (0.46)

(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 $319.9 million ($24.65/boe) for Q1/2025 compared to $344.1 million ($25.11/boe) for Q1/2024. Total depletion and depreciation expense and depletion and depreciation per boe were lower in Q1/2025 relative to Q1/2024 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 Q1/2025.

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 March 31, 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 unvested share awards outstanding and changes in the market price of our common shares.

We recorded SBC expense of $0.8 million for Q1/2025 compared to $9.5 million for Q1/2024. SBC expense for Q1/2025 reflects a decrease in the Company's share price which resulted in lower SBC expense relative to Q1/2024.

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 March 31		
($ thousands except for exchange rates)	**2025**	2024	Change
Unrealized foreign exchange (gain) loss	**$ (3,475)**	$ 38,718	$ (42,193)
Realized foreign exchange (gain) loss	**(403)**	1,219	(1,622)
Foreign exchange (gain) loss	**$ (3,878)**	$ 39,937	$ (43,815)
CAD/USD exchange rates:			
At beginning of period	**1.4405**	1.3205	
At end of period	**1.4379**	1.3533	

We recorded a foreign exchange gain of $3.9 million for Q1/2025 compared to losses of $39.9 million for Q1/2024.

The unrealized foreign exchange gain of $3.5 million for Q1/2025 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 March 31, 2025 compared to December 31, 2024. The unrealized foreign exchange loss of $38.7 million for Q1/2024 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 March 31, 2024 compared to 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 gain of $0.4 million for Q1/2025 compared to losses of $1.2 million for Q1/2024.

INCOME TAXES

	Three Months Ended March 31		
($ thousands)	**2025**	2024	Change
Current income tax expense	**$ 2,152**	$ 1,680	$ 472
Deferred income tax expense	**18,611**	15,801	2,810
Total income tax expense	**$ 20,763**	$ 17,481	$ 3,282
Current income tax expense per boe (1)	**$ 0.17**	$ 0.12	$ 0.05

(1) Current income tax expense per boe is calculated as current income tax expense divided by barrels of oil equivalent production volume for the applicable period.

Current income tax expense of $2.2 million for Q1/2025 is consistent with $1.7 million recorded for Q1/2024 and primarily relates to repatriation and related taxes.

We recorded deferred income tax expense of $18.6 million for Q1/2025 compared to $15.8 million for Q1/2024. The deferred tax expense for Q1/2025 increased compared to Q1/2024 as a result of higher income generated for the period.

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 and we estimate it could take between two and 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 Tax Court of Canada, 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 $211.6 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. If, after exhausting available appeals, the deduction of Losses continues to be disallowed, either the trusts or their corporate beneficiary will owe cash taxes, late payment interest and potential penalties. The amount of cash taxes owing, late payment interest and potential penalties are dependent upon the taxpayer(s) ultimately liable (the trusts or their corporate beneficiary) and the amount of unused tax shelter available to the taxpayer(s) to offset the reassessed income, including tax shelter from subsequent years that may be carried back and applied to prior years.

NET INCOME (LOSS) AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income for the three months ended March 31, 2025 and 2024 are set forth in the following table.

	Three Months Ended March 31		
($ thousands)	**2025**	2024	Change
Petroleum and natural gas sales	**$ 999,130**	$ 984,192	$ 14,938
Royalties	**(207,937)**	(209,171)	1,234
Revenue, net of royalties	**791,193**	775,021	16,172
Expenses			
Operating	**(147,703)**	(173,435)	25,732
Transportation	**(30,512)**	(29,835)	(677)
Blending and other	**(72,820)**	(64,208)	(8,612)
Operating netback (1)	**$ 540,158**	$ 507,543	$ 32,615
General and administrative	**(25,606)**	(22,412)	(3,194)
Cash interest	**(46,787)**	(53,280)	6,493
Realized financial derivatives (loss) gain	**(194)**	5,488	(5,682)
Realized foreign exchange gain (loss)	**403**	(1,219)	1,622
Cash other expense	**(1,189)**	(1,071)	(118)
Current income tax expense	**(2,152)**	(1,680)	(472)
Cash share-based compensation	**(763)**	(9,523)	8,760
Adjusted funds flow (2)	**$ 463,870**	$ 423,846	$ 40,024
Transaction costs	**—**	(1,539)	1,539
Exploration and evaluation	**(107)**	(18)	(89)
Depletion and depreciation	**(319,923)**	(344,137)	24,214
Non-cash financing and interest	**(8,459)**	(7,987)	(472)
Unrealized financial derivatives loss	**(49,425)**	(32,350)	(17,075)
Unrealized foreign exchange gain (loss)	**3,475**	(38,718)	42,193
(Loss) gain on dispositions	**(1,229)**	2,661	(3,890)
Deferred income tax expense	**(18,611)**	(15,801)	(2,810)
Net income (loss)	**$ 69,591**	$ (14,043)	$ 83,634

(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 $463.9 million for Q1/2025 compared $423.8 million for Q1/2024. The $40.0 million increase in adjusted funds flow was primarily due to higher commodity prices that resulted in increased revenues net of royalties and lower operating expense.

We reported net income of $69.6 million for Q1/2025 compared to a net loss of $14.0 million for Q1/2024. The increase in net income for Q1/2025 is the result of a lower depletion rate and associated depletion expense and an unrealized foreign exchange gain, partially offset by a higher unrealized financial derivatives loss.

OTHER COMPREHENSIVE INCOME

Other comprehensive income 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 $8.4 million for Q1/2025 relates to the change in value of our U.S. net assets and is due to changes in the value of the Canadian dollar relative to the U.S. dollar at March 31, 2025 compared to December 31, 2024. The CAD/USD exchange rate was 1.4379 CAD/USD as at March 31, 2025 compared to 1.4405 CAD/USD at December 31, 2024.

CAPITAL EXPENDITURES

Capital expenditures for the three months ended March 31, 2025 and 2024 are summarized as follows.

	Three Months Ended March 31					
	2025			2024		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 167,478**	**$ 185,762**	**$ 353,240**	$ 126,007	$ 219,939	$ 345,946
Facilities and other	**16,841**	**35,016**	**51,857**	32,119	34,486	66,605
Exploration and development expenditures	**$ 184,319**	**$ 220,778**	**$ 405,097**	$ 158,126	$ 254,425	$ 412,551
Property acquisitions	**$ 469**	**$ 788**	**$ 1,257**	$ 34,275	$ 1,128	$ 35,403
Proceeds from dispositions	**$ (2,677)**	**$ 411**	**$ (2,266)**	$ (25)	$ —	$ (25)

Exploration and development expenditures were $405.1 million for Q1/2025 compared to $412.6 million for Q1/2024. Exploration and development expenditures in Q1/2025 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 $184.3 million in Q1/2025 compared to $158.1 million in Q1/2024. Drilling and completion spending of $167.5 million in Q1/2025 was higher than Q1/2024 when we spent $126.0 million which reflects increased development activity levels on our light and heavy oil properties.

Total U.S. exploration and development expenditures were $220.8 million for Q1/2025 compared to $254.4 million in Q1/2024. The decrease in exploration and development expenditures for Q1/2025 compared to Q1/2024 reflects lower development activity on our non-operated Eagle Ford properties.

Exploration and development expenditures of $405.1 million for Q1/2025 were consistent with expectations and reflect our active Q1/2025 drilling programs. We expect exploration and development expenditures for 2025 to be at the low end of our annual guidance range of $1.2 - $1.3 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 March 31, 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 $2.4 billion at March 31, 2025 was $26.9 million lower than $2.4 billion at December 31, 2024 which reflects our allocation of free cash flow to debt repayment in Q1/2025. Free cash flow is allocated to debt repayment and shareholder returns including share buybacks and a quarterly dividend. At current commodity prices we expect net debt to decrease in late 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.

Credit Facilities

At March 31, 2025, we had $250.3 million of principal amount outstanding under our revolving credit facilities which total US$1.1 billion ($1.6 billion) (the "Credit Facilities") and mature on May 9, 2028. 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.

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, CORRA 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 6.9% for Q1/2025 compared to 7.8% for Q1/2024. The interest rate on our Credit Facilities has decreased with lower government benchmark rates.

At March 31, 2025, we had $5.0 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 March 31, 2025.

Covenant Description	Position as at March 31, 2025	Covenant
Senior Secured Debt [1] to Bank EBITDA [2] (Maximum Ratio)	**0.1:1.0**	3.5:1.0
Interest Coverage [3] (Minimum Ratio)	**11.2:1.0**	3.5:1.0
Total Debt [4] to Bank EBITDA [2] (Maximum Ratio)	**1.0:1.0**	4:0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at March 31, 2025, the Company's Senior Secured Debt totaled $255.0 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 March 31, 2025 was $2.2 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 March 31, 2025 was $198.0 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 March 31, 2025, the Company's Total Debt totaled $2.2 billion of principal amounts outstanding.

Long-Term Notes

At March 31, 2025 we have two issuances of long-term notes outstanding with a total principal amount of $2.0 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.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the three months ended March 31, 2025, we issued 0.1 million common shares pursuant to our share-based compensation program. As at March 31, 2025, we had 770.0 million common shares issued and outstanding and no preferred shares issued and outstanding. As at May 2, 2025, there were 768.6 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 three months ended March 31, 2025, we repurchased 3.7 million common shares under our normal course issuer bid ("NCIB") at an average price of $3.49 per share for total consideration of $12.8 million. In June 2024, we renewed our NCIB under which Baytex is permitted to purchase for cancellation up to 70.1 million common shares over the 12-month period commencing July 2, 2024, which represents 10% of Baytex's public float, as defined by the TSX, as of June 18, 2024. 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.

During the three months ended March 31, 2025, Baytex recorded a $0.2 million liability related to the 2% federal tax on equity repurchases (December 31, 2024 - $4.3 million), which is charged to shareholders' capital.

On January 2 and April 1, 2025, we paid a quarterly cash dividend of $0.0225 per share to shareholders of record. On May 5, 2025, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on July 2, 2025 to shareholders of record on June 13, 2025. These dividends are designated as "eligible dividends" for Canadian income tax purposes. For U.S. income tax purposes, Baytex's dividends are considered "qualified dividends."

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of March 31, 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	**$ 250,284**	$ —	$ —	$ 250,284	$ —
Long-term notes - principal	**1,977,044**	—	—	—	1,977,044
Interest on long-term notes (1)	**921,651**	158,748	317,495	317,495	127,913
Lease obligations - principal	**37,586**	14,815	14,114	7,441	1,216
Processing agreements	**5,682**	948	1,071	543	3,120
Transportation agreements	**218,825**	61,379	88,238	28,696	40,512
Total	**$ 3,411,072**	$ 235,890	$ 420,918	$ 604,459	$ 2,149,805

(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)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Petroleum and natural gas sales	**999,130**	1,017,017	1,074,623	1,133,123	984,192	1,065,515	1,163,010	598,760
Net income (loss)	**69,591**	(38,477)	185,219	103,898	(14,043)	(625,830)	127,430	213,603
Per common share - basic	**0.09**	(0.05)	0.23	0.13	(0.02)	(0.75)	0.15	0.37
Per common share - diluted	**0.09**	(0.05)	0.23	0.13	(0.02)	(0.75)	0.15	0.36
Adjusted funds flow (1)	**463,870**	461,886	537,947	532,839	423,846	502,148	581,623	273,590
Per common share - basic	**0.60**	0.59	0.68	0.65	0.52	0.60	0.68	0.47
Per common share - diluted	**0.60**	0.59	0.67	0.65	0.52	0.60	0.68	0.47
Free cash flow (2)	**52,529**	254,838	220,159	180,673	(88)	290,785	158,440	96,313
Per common share - basic	**0.07**	0.33	0.28	0.22	—	0.35	0.19	0.17
Per common share - diluted	**0.07**	0.33	0.28	0.22	—	0.35	0.18	0.16
Cash flows from operating activities	**431,317**	468,865	550,042	505,584	383,773	474,452	444,033	192,308
Per common share - basic	**0.56**	0.60	0.69	0.62	0.47	0.57	0.52	0.33
Per common share - diluted	**0.56**	0.60	0.69	0.62	0.47	0.57	0.52	0.33
Dividends declared	**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	—
Exploration and development	**405,097**	198,177	306,332	339,573	412,551	199,214	409,191	170,704
Canada	**184,319**	108,971	120,473	101,916	158,126	75,137	107,053	96,403
U.S.	**220,778**	89,206	185,859	237,657	254,425	124,077	302,138	74,301
Property acquisitions	**1,257**	12,621	1,042	3,349	35,403	33,923	4,277	(62)
Proceeds from dispositions	**(2,266)**	(42,339)	(1,436)	(2,695)	(25)	(159,745)	(226)	(50)
Net debt (1)	**2,390,250**	2,417,172	2,493,269	2,639,014	2,639,841	2,534,287	2,824,348	2,814,844
Total assets	**7,824,576**	7,759,745	7,614,157	7,770,926	7,717,495	7,460,931	8,946,181	8,617,444
Common shares outstanding	**770,039**	773,590	787,328	804,977	821,322	821,681	845,360	862,192
Daily production								
Total production (boe/d)	**144,194**	152,894	154,468	154,194	150,620	160,373	150,600	89,761
Canada (boe/d)	**62,380**	65,332	64,668	63,688	62,081	64,744	63,289	55,874
U.S. (boe/d)	**81,814**	87,562	89,800	90,506	88,540	95,629	87,311	33,887
Benchmark prices								
WTI oil (US$/bbl)	**71.42**	70.27	75.10	80.57	76.96	78.32	82.26	73.78
WCS heavy oil ($/bbl)	**84.33**	80.77	83.98	91.72	77.73	76.86	93.02	78.85
Edmonton par oil ($/bbl)	**95.27**	94.98	97.91	105.30	92.16	99.72	107.93	95.13
CAD/USD avg exchange rate	**1.4350**	1.3992	1.3636	1.3684	1.3488	1.3619	1.3410	1.3431
AECO natural gas ($/mcf)	**2.02**	1.46	0.81	1.44	2.05	2.66	2.39	2.35
NYMEX natural gas (US$/mmbtu)	**3.65**	2.79	2.16	1.89	2.24	2.88	2.55	2.10
Total sales, net of blending and other expense ($/boe) (2)	**71.38**	66.60	71.97	75.93	67.12	68.00	80.34	66.82
Royalties ($/boe) (3)	**(16.02)**	(14.69)	(15.75)	(17.14)	(15.26)	(15.49)	(17.33)	(13.21)
Operating expense ($/boe) (3)	**(11.38)**	(10.36)	(11.76)	(11.95)	(12.65)	(11.17)	(12.57)	(14.62)
Transportation expense ($/boe) (3)	**(2.35)**	(2.35)	(2.60)	(2.37)	(2.18)	(2.02)	(2.02)	(1.78)
Operating netback ($/boe) (2)	**41.63**	39.20	41.86	44.47	37.03	39.32	48.42	37.21
Financial derivatives (loss) gain ($/boe) (3)	**(0.01)**	(0.15)	0.02	(0.16)	0.40	0.84	0.15	2.00
Operating netback after financial derivatives ($/boe) (2)	**41.62**	39.05	41.88	44.31	37.43	40.16	48.57	39.21

(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 remained relatively stable. Production increased from 89,761 boe/d in Q2/2023 and reached 144,194 boe/d in Q1/2025 due to the merger with Ranger Oil Corporation which closed on June 20, 2023 and our successful development programs in Canada and the U.S.

Crude oil prices strengthened in Q3/2023 as a result of the announcement by OPEC+ of new production cuts, as well as the extension of voluntary production cuts by Saudi Arabia and Russia. This was reflected in our realized sales price of $80.34/boe for Q3/2023, which is our strongest realized pricing in the most recent eight quarters. Our realized price of $71.38/boe for Q1/2025 reflects relatively stable benchmark prices during the period.

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 $463.9 million and cash flows from operating activities of $431.3 million for Q1/2025 reflect strong production results from our development plans in the U.S. and Canada.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt(1) decreased to $2.4 billion at Q1/2025 from $2.8 billion at Q2/2023 which reflects free cash flow(2) of $1.2 billion generated in the period since Q2/2023, along with $579.4 million allocated to shareholder returns, partially offset by a weaker Canadian dollar at Q1/2025 which increases 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 proposed standards that are aligned with the ISSB release, but include suggestions for Canadian-specific modifications. The Canadian Securities Administrators ("CSA") have also issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters which sets forth additional reporting requirements for Canadian Public Companies. In April 2025, the CSA announced it is pausing development of new sustainability reporting requirements to allow issuers to adapt to recent developments in the U.S. and globally. Baytex continues to monitor developments on these reporting requirements and has not yet quantified the cost to comply with these regulations.

OFF BALANCE SHEET TRANSACTIONS

We do not have any material financial arrangements that are excluded from the consolidated financial statements as at March 31, 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 three months ended March 31, 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 March 31	
($ thousands)	**2025**	2024
Petroleum and natural gas sales	**$ 999,130**	$ 984,192
Light oil and condensate [1]	**(557,964)**	(601,115)
NGL [1]	**(53,676)**	(45,930)
Natural gas [1]	**(48,779)**	(32,223)
Heavy oil	**$ 338,711**	$ 304,924
Blending and other expense [2]	**(72,820)**	(64,208)
Heavy oil, net of blending and other expense	**$ 265,891**	$ 240,716

(1) Component of petroleum and natural gas sales. See Note 12 - Petroleum and Natural Gas Sales in the consolidated financial statements for the three months ended March 31, 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 March 31	
($ thousands)	**2025**	2024
Petroleum and natural gas sales	**$ 999,130**	$ 984,192
Blending and other expense	**(72,820)**	(64,208)
Total sales, net of blending and other expense	**926,310**	919,984
Royalties	**(207,937)**	(209,171)
Operating expense	**(147,703)**	(173,435)
Transportation expense	**(30,512)**	(29,835)
Operating netback	**$ 540,158**	$ 507,543
Realized financial derivatives gain [1]	**(194)**	5,488
Operating netback after realized financial derivatives	**$ 539,964**	$ 513,031

(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 months ended March 31, 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 March 31	
($ thousands)	**2025**	2024
Cash flows from operating activities	**$ 431,317**	$ 383,773
Change in non-cash working capital	**29,034**	32,023
Additions to oil and gas properties	**(405,097)**	(412,551)
Payments on lease obligations	**(2,725)**	(4,872)
Transaction costs	**—**	1,539
Free cash flow	**$ 52,529**	$ (88)

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)		**March 31, 2025**		December 31, 2024
Credit facilities	**$**	**234,683**	$	324,346
Unamortized debt issuance costs - Credit facilities (1)		**15,601**		16,861
Long-term notes		**1,930,809**		1,932,890
Unamortized debt issuance costs - Long-term notes (1)		**46,235**		47,729
Trade payables		**582,053**		512,473
Share-based compensation liability		**12,602**		24,732
Dividends payable		**17,334**		17,598
Other long-term liabilities		**20,849**		20,887
Cash		**(5,966)**		(16,610)
Trade receivables		**(391,905)**		(387,266)
Prepaids and other assets		**(72,045)**		(76,468)
Net debt	**$**	**2,390,250**	$	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 months ended March 31, 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 March 31		
($ thousands)		**2025**		2024
Cash flow from operating activities	**$**	**431,317**	$	383,773
Change in non-cash working capital		**29,034**		32,023
Asset retirement obligations settled		**3,519**		6,511
Transaction costs		**—**		1,539
Adjusted funds flow	**$**	**463,870**	$	423,846

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 March 31, 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)

		As at	
	Notes	**March 31, 2025**	December 31, 2024
ASSETS			
Current assets			
Cash	16	**$ 5,966**	$ 16,610
Trade receivables	12, 16	**391,905**	387,266
Prepaids and other assets		**17,563**	20,178
Financial derivatives	16	**2,325**	25,573
		417,759	449,627
Non-current assets			
Exploration and evaluation assets	4	**125,440**	124,355
Oil and gas properties	5	**7,022,393**	6,921,168
Other plant and equipment		**7,448**	8,025
Lease assets		**29,933**	22,068
Prepaids and other assets	13	**54,482**	56,290
Deferred income tax asset	13	**167,121**	178,212
		$ 7,824,576	$ 7,759,745
LIABILITIES			
Current liabilities			
Trade payables	16	**$ 582,053**	$ 512,473
Financial derivatives	16	**23,752**	—
Share-based compensation liability	10	**10,755**	18,806
Dividends payable	9, 16	**17,334**	17,598
Lease obligations		**12,794**	9,193
Asset retirement obligations	8	**16,136**	15,656
		662,824	573,726
Non-current liabilities			
Other long-term liabilities		**20,849**	20,887
Share-based compensation liability	10	**1,847**	5,926
Financial derivatives	16	**4,070**	1,645
Credit facilities	6	**234,683**	324,346
Long-term notes	7	**1,930,809**	1,932,890
Lease obligations		**19,945**	15,459
Asset retirement obligations	8	**651,069**	625,295
Deferred income tax liability	13	**96,282**	88,561
		3,622,378	3,588,735
SHAREHOLDERS' EQUITY			
Shareholders' capital	9	**6,108,446**	6,137,479
Contributed surplus		**378,195**	361,854
Accumulated other comprehensive income		**1,084,839**	1,093,261
Deficit		**(3,369,282)**	(3,421,584)
		4,202,198	4,171,010
		$ 7,824,576	$ 7,759,745

Subsequent events (notes 9 and 16)

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended March 31	
	Notes	**2025**	2024
Revenue, net of royalties			
Petroleum and natural gas sales	12	**$ 999,130**	$ 984,192
Royalties		**(207,937)**	(209,171)
		791,193	775,021
Expenses			
Operating		**147,703**	173,435
Transportation		**30,512**	29,835
Blending and other		**72,820**	64,208
General and administrative		**25,606**	22,412
Transaction costs		**—**	1,539
Exploration and evaluation	4	**107**	18
Depletion and depreciation		**319,923**	344,137
Share-based compensation	10	**763**	9,523
Financing and interest	14	**55,246**	61,267
Financial derivatives loss	16	**49,619**	26,862
Foreign exchange (gain) loss	15	**(3,878)**	39,937
Loss (gain) on dispositions		**1,229**	(2,661)
Other expense		**1,189**	1,071
		700,839	771,583
Net income before income taxes		**90,354**	3,438
Income tax expense	13		
Current income tax expense		**2,152**	1,680
Deferred income tax expense		**18,611**	15,801
		20,763	17,481
Net income (loss)		**$ 69,591**	$ (14,043)
Other comprehensive (loss) income			
Foreign currency translation adjustment		**(8,422)**	110,563
Comprehensive income		**$ 61,169**	$ 96,520
Net income (loss) per common share	11		
Basic		**$ 0.09**	$ (0.02)
Diluted		**$ 0.09**	$ (0.02)
Weighted average common shares (000's)	11		
Basic		**771,443**	821,710
Diluted		**774,257**	821,710

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		(5,018)	2,013	—	—	**(3,005)**
Dividends declared		—	—	—	(18,494)	**(18,494)**
Comprehensive income (loss)		—	—	110,563	(14,043)	**96,520**
Balance at March 31, 2024		$ 6,523,438	$ 195,090	$ 801,480	$ (3,618,733)	**$ 3,901,275**
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	(29,363)	16,341	—	—	**(13,022)**
Dividends declared	9	—	—	—	(17,289)	**(17,289)**
Comprehensive (loss) income		—	—	(8,422)	69,591	**61,169**
Balance at March 31, 2025		$ 6,108,446	$ 378,195	$ 1,084,839	$ (3,369,282)	**$ 4,202,198**

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended March 31	
	Notes	**2025**	2024
CASH PROVIDED BY (USED IN):			
Operating activities			
Net income (loss)		**$ 69,591**	$ (14,043)
Adjustments for:			
Unrealized foreign exchange (gain) loss	15	**(3,475)**	38,718
Exploration and evaluation	4	**107**	18
Depletion and depreciation		**319,923**	344,137
Non-cash financing and interest	14	**8,459**	7,987
Unrealized financial derivatives loss	16	**49,425**	32,350
Loss (gain) on dispositions		**1,229**	(2,661)
Deferred income tax expense	13	**18,611**	15,801
Asset retirement obligations settled	8	**(3,519)**	(6,511)
Change in non-cash working capital		**(29,034)**	(32,023)
Cash flows from operating activities		**431,317**	383,773
Financing activities			
Decrease in credit facilities		**(89,705)**	(21,555)
Payments on lease obligations		**(2,725)**	(4,872)
Repurchase of common shares	9	**(13,022)**	(3,005)
Dividends declared	9	**(17,289)**	(18,494)
Change in non-cash working capital		**854**	2,005
Cash flows used in financing activities		**(121,887)**	(45,921)
Investing activities			
Additions to oil and gas properties	5	**(405,097)**	(412,551)
Additions to other plant and equipment		**(559)**	(2,257)
Property acquisitions		**(1,257)**	(35,403)
Proceeds from dispositions		**2,266**	25
Change in non-cash working capital		**84,573**	85,659
Cash flows used in investing activities		**(320,074)**	(364,527)
Change in cash		**(10,644)**	(26,675)
Cash, beginning of period		**16,610**	55,815
Cash, end of period		**$ 5,966**	$ 29,140
Supplementary information			
Interest paid		**$ 36,675**	$ 18,289
Income taxes paid		**$ 5,320**	$ 4,544

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 and the New York Stock Exchange under the symbol BTE. The Company’s head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PREPARATION

The condensed consolidated interim financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). These consolidated financial statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with the annual consolidated financial statements as at and for the year ended December 31, 2024 ("2024 annual consolidated financial statements").

The consolidated financial statements were approved by the Board of Directors of Baytex on May 5, 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 proposed standards 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 March 31	**2025**	2024	**2025**	2024	**2025**	2024	**2025**	2024
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 454,151**	$ 416,313	**$ 544,979**	$ 567,879	**$ —**	$ —	**$ 999,130**	$ 984,192
Royalties	**(59,256)**	(56,564)	**(148,681)**	(152,607)	**—**	—	**(207,937)**	(209,171)
	394,895	359,749	**396,298**	415,272	**—**	—	**791,193**	775,021
Expenses								
Operating	**75,580**	85,403	**72,123**	88,032	**—**	—	**147,703**	173,435
Transportation	**18,779**	18,210	**11,733**	11,625	**—**	—	**30,512**	29,835
Blending and other	**72,820**	64,208	**—**	—	**—**	—	**72,820**	64,208
General and administrative	**—**	—	**—**	—	**25,606**	22,412	**25,606**	22,412
Transaction costs	**—**	—	**—**	—	**—**	1,539	**—**	1,539
Exploration and evaluation	**107**	18	**—**	—	**—**	—	**107**	18
Depletion and depreciation	**114,459**	116,996	**201,384**	224,439	**4,080**	2,702	**319,923**	344,137
Share-based compensation	**—**	—	**—**	—	**763**	9,523	**763**	9,523
Financing and interest	**—**	—	**—**	—	**55,246**	61,267	**55,246**	61,267
Financial derivatives loss	**—**	—	**—**	—	**49,619**	26,862	**49,619**	26,862
Foreign exchange (gain) loss	**—**	—	**—**	—	**(3,878)**	39,937	**(3,878)**	39,937
Loss (gain) on dispositions	**1,229**	(2,411)	**—**	(250)	**—**	—	**1,229**	(2,661)
Other expense	**—**	—	**—**	—	**1,189**	1,071	**1,189**	1,071
	282,974	282,424	**285,240**	323,846	**132,625**	165,313	**700,839**	771,583
Net income (loss) before income taxes	**111,921**	77,325	**111,058**	91,426	**(132,625)**	(165,313)	**90,354**	3,438
Income tax expense								
Current income tax expense							**2,152**	1,680
Deferred income tax expense							**18,611**	15,801
							20,763	17,481
Net income (loss)	**$ 111,921**	$ 77,325	**$ 111,058**	$ 91,426	**$ (132,625)**	$ (165,313)	**$ 69,591**	$ (14,043)
Additions to oil and gas properties	**184,319**	158,126	**220,778**	254,425	**—**	—	**405,097**	412,551
Property acquisitions	**469**	34,275	**788**	1,128	**—**	—	**1,257**	35,403
Proceeds from dispositions	**(2,677)**	(25)	**411**	—	**—**	—	**(2,266)**	(25)

	March 31, 2025	December 31, 2024
Canadian assets	$ 2,464,271	$ 2,381,991
U.S. assets	5,320,599	5,322,088
Corporate assets	39,706	55,666
Total consolidated assets	$ 7,824,576	$ 7,759,745

4. EXPLORATION AND EVALUATION ASSETS

	March 31, 2025	December 31, 2024
Balance, beginning of period	$ 124,355	$ 90,919
Property acquisitions	4,692	39,355
Divestitures	(1,472)	(2,009)
Exploration and evaluation expense	(107)	(779)
Transfer to oil and gas properties (note 5)	(2,028)	(3,131)
Balance, end of period	$ 125,440	$ 124,355

At March 31, 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
Capital expenditures	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
Capital expenditures	405,097	—	405,097
Property acquisitions	842	—	842
Transfers from exploration and evaluation assets (note 4)	2,028	—	2,028
Change in asset retirement obligations (note 8)	24,825	—	24,825
Divestitures	(28,230)	21,386	(6,844)
Foreign currency translation	(17,673)	8,793	(8,880)
Depletion	—	(315,843)	(315,843)
Balance, March 31, 2025	$ 17,830,233	$ (10,807,840)	$ 7,022,393

At March 31, 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

		March 31, 2025		December 31, 2024
Credit facilities - U.S. dollar denominated [1]	$	152,861	$	206,826
Credit facilities - Canadian dollar denominated		97,423		134,381
Credit facilities - principal [2]	$	250,284	$	341,207
Unamortized debt issuance costs		(15,601)		(16,861)
Credit facilities	$	234,683	$	324,346

(1) U.S. dollar denominated credit facilities balance was US$106.3 million as at March 31, 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 March 31, 2025 is the result of net repayments of $89.7 million and a decrease in the reported amount of U.S. denominated debt of $1.2 million due to foreign exchange.

At March 31, 2025, Baytex had US$1.1 billion ($1.6 billion) of revolving credit facilities that mature on May 9, 2028. 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, CORRA 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 6.9% for the three months ended March 31, 2025 (7.8% for three months ended March 31, 2024).

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at March 31, 2025.

Covenant Description	Position as at March 31, 2025	Covenant
Senior Secured Debt [1] to Bank EBITDA [2] (Maximum Ratio)	0.1:1.0	3.5:1.0
Interest Coverage [3] (Minimum Ratio)	11.2:1.0	3.5:1.0
Total Debt [4] to Bank EBITDA [2] (Maximum Ratio)	1.0:1.0	4:0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at March 31, 2025, the Company's Senior Secured Debt totaled $255.0 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 March 31, 2025 was $2.2 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 March 31, 2025 was $198.0 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 March 31, 2025, the Company's Total Debt totaled $2.2 billion of principal amounts outstanding.

At March 31, 2025, Baytex had $5.0 million of outstanding letters of credit (December 31, 2024 - $5.8 million outstanding) under the Credit Facilities.

7. LONG-TERM NOTES

	March 31, 2025	December 31, 2024
8.50% notes due April 30, 2030 (1)	**$ 1,150,280**	$ 1,152,360
7.375% notes due March 15, 2032 (2)	**826,764**	828,259
Total long-term notes - principal (3)	**$ 1,977,044**	$ 1,980,619
Unamortized debt issuance costs	**(46,235)**	(47,729)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,930,809**	$ 1,932,890

(1) The U.S. dollar denominated principal outstanding of the 8.50% notes was US$800.0 million as at March 31, 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 March 31, 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 March 31, 2025 is the result of changes in the reported amount of U.S. denominated debt of $3.6 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.

8. ASSET RETIREMENT OBLIGATIONS

	March 31, 2025	December 31, 2024
Balance, beginning of period	**$ 640,951**	$ 623,399
Liabilities incurred (1)	**7,738**	32,635
Liabilities settled	**(3,519)**	(28,793)
Liabilities acquired from property acquisitions	**—**	814
Liabilities divested	**(544)**	(9,482)
Accretion (note 14)	**5,649**	21,226
Change in estimate (1)	**1,780**	10,113
Changes in discount and inflation rates (1)(2)	**15,307**	(17,495)
Foreign currency translation	**(157)**	8,534
Balance, end of period	**$ 667,205**	$ 640,951
Less current portion of asset retirement obligations	**16,136**	15,656
Non-current portion of asset retirement obligations	**$ 651,069**	$ 625,295

(1) The total of these items reflects the total change in asset retirement obligations of $24.8 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 March 31, 2025 were 3.2% 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 March 31, 2025 were 4.6% 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 March 31, 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	(3,663)		(29,363)
Balance, March 31, 2025	**770,039**	**$**	**6,108,446**

Normal Course Issuer Bid ("NCIB") Share Repurchases

On June 26, 2024, Baytex announced that the Toronto Stock Exchange ("TSX") accepted the renewal of the NCIB under which Baytex is permitted to purchase for cancellation up to 70.1 million common shares over the 12-month period commencing July 2, 2024. The number of shares authorized for repurchase represented 10% of the Company's public float, as defined by the TSX, as at June 18, 2024. On June 18, 2024, Baytex had 808.0 million common shares outstanding.

During the three months ended March 31, 2025, Baytex recorded $13.0 million related to common share repurchases, which includes $12.8 million of consideration paid for the repurchase and cancellation of common shares as well as $0.2 million of federal tax levied on equity repurchases.

Purchases are made on the open market at prices prevailing at the time of the transaction. During the three months ended March 31, 2025, Baytex repurchased and cancelled 3.7 million common shares at an average price of $3.49 per share for total consideration of $12.8 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 three months ended March 31, 2025, Baytex recorded a $0.2 million liability related to the 2% federal tax on equity repurchases (December 31, 2024 - $4.3 million), which is charged to shareholders’ capital.

Dividends

On January 2 and April 1, 2025, we paid a quarterly cash dividend of $0.0225 per share to shareholders of record. On May 5, 2025, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on July 2, 2025 to shareholders of record on June 13, 2025.

10. SHARE-BASED COMPENSATION PLAN

For the three months ended March 31, 2025 the Company recorded share-based compensation expense of $0.8 million ($9.5 million for the three months ended March 31, 2024) which is related to cash-settled awards.

The Company's closing share price on the Toronto Stock Exchange on March 31, 2025 was $3.19 (December 31, 2024 - $3.70 and March 31, 2024 - $4.89).

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

The weighted average fair value of share awards granted during the three months ended March 31, 2025 was $2.93 per restricted and performance award ($4.27 for the three months ended March 31, 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 three months ended March 31, 2025 was $2.93 per incentive award ($4.26 for the three months ended March 31, 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 three months ended March 31, 2025 was $2.93 per DSU award ($4.29 for the three months ended March 31, 2024).

The number of awards outstanding is detailed below:

(000s)	Restricted awards	Performance awards	Incentive awards	Director Share Units	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	3,732	5,403	127	9,267
Forfeited by performance factor	—	(244)	—	—	(244)
Vested	(691)	(1,297)	(2,233)	—	(4,221)
Forfeited	—	—	(105)	—	(105)
Total, March 31, 2025	**140**	**5,673**	**8,340**	**1,545**	**15,698**

11. NET INCOME (LOSS) 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 March 31					
	2025			2024		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	Net loss	Weighted average common shares (000s)	Net loss per share
Net income (loss) - basic	**$ 69,591**	**771,443**	**$ 0.09**	$ (14,043)	821,710	$ (0.02)
Dilutive effect of share awards	**—**	**2,814**	**—**	—	—	—
Net income (loss) - diluted	**$ 69,591**	**774,257**	**$ 0.09**	$ (14,043)	821,710	$ (0.02)

For the three months ended March 31, 2025, no share awards were excluded from the calculation of diluted income per share. For the three months ended March 31, 2024, all share awards were excluded from the calculation of diluted loss per share as their effect was anti-dilutive given the Company recorded a loss.

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 March 31					
	2025			2024		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 99,469**	**$ 458,495**	**$ 557,964**	$ 95,221	$ 505,894	$ 601,115
Heavy oil	**338,711**	**—**	**338,711**	304,924	—	304,924
NGL	**7,888**	**45,788**	**53,676**	6,368	39,562	45,930
Natural gas	**8,083**	**40,696**	**48,779**	9,800	22,423	32,223
Total petroleum and natural gas sales	**$ 454,151**	**$ 544,979**	**$ 999,130**	$ 416,313	$ 567,879	$ 984,192

Included in trade receivables at March 31, 2025 is $337.2 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:

	Three Months Ended March 31	
	2025	2024
Net income before income taxes	**$ 90,354**	$ 3,438
Expected income taxes at the statutory rate of 24.38% (2024 – 24.64%)	**22,028**	847
Change in income taxes resulting from:		
Effect of foreign exchange	**(436)**	4,847
Effect of rate adjustments for foreign jurisdictions	**(2,996)**	(1,817)
Effect of change in deferred tax benefit not recognized (1)	**(436)**	11,729
Repatriation and related taxes	**2,297**	2,277
Adjustments, assessments and other	**306**	(402)
Income tax expense	**$ 20,763**	$ 17,481

(1) A deferred tax asset of $31.4 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.

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 and we estimate it could take between two and 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 Tax Court of Canada, 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 $211.6 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. If, after exhausting available appeals, the deduction of 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 March 31	
	2025	2024
Interest on Credit Facilities	**$ 6,183**	$ 18,289
Interest on long-term notes	**40,279**	34,678
Interest on lease obligations	**325**	313
Cash interest	**$ 46,787**	$ 53,280
Amortization of debt issue costs	**2,810**	3,060
Accretion on asset retirement obligations (note 8)	**5,649**	4,927
Financing and interest	**$ 55,246**	$ 61,267

15. FOREIGN EXCHANGE

	Three Months Ended March 31	
	2025	2024
Unrealized foreign exchange (gain) loss	**$ (3,475)**	$ 38,718
Realized foreign exchange (gain) loss	**(403)**	1,219
Foreign exchange (gain) loss	**$ (3,878)**	$ 39,937

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

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

	March 31, 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	**$ 2,325**	**$ 2,325**	$ 25,573	$ 25,573	Level 2
Total	**$ 2,325**	**$ 2,325**	$ 25,573	$ 25,573	
Amortized cost					
Cash	**$ 5,966**	**$ 5,966**	$ 16,610	$ 16,610	—
Trade receivables	**391,905**	**391,905**	387,266	387,266	—
Total	**$ 397,871**	**$ 397,871**	$ 403,876	$ 403,876	
Financial Liabilities					
Fair value through profit and loss					
Financial derivatives	**$ (27,822)**	**$ (27,822)**	$ (1,645)	$ (1,645)	Level 2
Total	**$ (27,822)**	**$ (27,822)**	$ (1,645)	$ (1,645)	
Amortized cost					
Trade payables	**$ (582,053)**	**$ (582,053)**	$ (512,473)	$ (512,473)	—
Dividends payable	**(17,334)**	**(17,334)**	(17,598)	(17,598)	—
Credit Facilities [(1)]	**(234,683)**	**(250,284)**	(324,346)	(341,207)	—
Long-term notes	**(1,930,809)**	**(1,967,432)**	(1,932,890)	(1,990,598)	Level 1
Total	**$ (2,764,879)**	**$ (2,817,103)**	$ (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 three months ended March 31, 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	
	March 31, 2025	December 31, 2024	**March 31, 2025**	December 31, 2024
U.S. dollar denominated	**US$5,444**	US$21,450	**US$1,425,876**	US$1,399,881

Commodity Price Risk

Financial Derivative Contracts

As at May 5, 2025, Baytex had the following commodity financial derivative contracts.

	Remaining Period	Volume	Price/Unit [1]	Index
Oil				
Basis differential	Apr 2025 to Dec 2025	2,000 bbl/d	WTI less US$2.75/bbl	MSW
Basis differential	May 2025 to Dec 2025	1,500 bbl/d	WTI less US$3.90/bbl	MSW
Basis differential [3]	May 2025 to Dec 2025	2,400 bbl/d	WTI less US$3.775/bbl	MSW
Basis differential	Apr 2025 to Jun 2025	3,000 bbl/d	WTI less US$13.50/bbl	WCS
Basis differential	Jul 2025 to Dec 2025	2,500 bbl/d	WTI less US$13.50/bbl	WCS
Basis differential	Apr 2025 to Dec 2025	19,000 bbl/d	WTI less US$13.14/bbl	WCS
Collar	Apr 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$94.25	WTI
Collar	Apr 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$93.90	WTI
Collar	Apr 2025 to Jun 2025	5,000 bbl/d	US$60.00/US$91.95	WTI
Collar	Apr 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$90.00	WTI
Collar	Apr 2025 to Jun 2025	3,000 bbl/d	US$60.00/US$89.55	WTI
Collar	Apr 2025 to Jun 2025	2,000 bbl/d	US$60.00/US$88.17	WTI
Collar	Apr 2025 to Jun 2025	5,000 bbl/d	US$60.00/US$90.50	WTI
Collar	Apr 2025 to Jun 2025	3,000 bbl/d	US$60.00/US$90.60	WTI
Collar	Apr 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]	Apr 2025 to Sep 2025	8,000 bbl/d	US$60.00/US$80.00	WTI
Natural Gas				
Collar	Apr 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.01	NYMEX
Collar	Apr 2025 to Dec 2025	5,000 mmbtu/d	US$3.25/US$4.03	NYMEX
Collar	Apr 2025 to Dec 2025	5,000 mmbtu/d	US$3.25/US$4.08	NYMEX
Collar	Apr 2025 to Dec 2025	3,000 mmbtu/d	US$3.25/US$4.135	NYMEX
Collar	Apr 2025 to Dec 2025	5,500 mmbtu/d	US$3.25/US$4.14	NYMEX
Collar	Apr 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.32	NYMEX
Collar	Apr 2025 to Dec 2025	3,000 mmbtu/d	US$3.00/US$4.85	NYMEX
Collar	Apr 2025 to Dec 2025	8,000 mmbtu/d	US$3.00/US$4.855	NYMEX
Collar	Apr 2025 to Jun 2025	3,000 mmbtu/d	US$3.00/US$4.05	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
AECO basis differential	Apr 2025 to Jun 2025	5,000 mmbtu/d	NYMEX less US$1.19/mmbtu	NYMEX

(1) Based on the weighted average price per unit for the period.
(2) Contracts include deferred premiums to be paid throughout the contract term. The weighted average deferred premium is $0.87/bbl.
(3) Contract entered subsequent to March 31, 2025.

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

	Three Months Ended March 31	
	2025	2024
Realized financial derivatives loss (gain)	**$ 194**	$ (5,488)
Unrealized financial derivatives loss	**49,425**	32,350
Financial derivatives loss	**$ 49,619**	$ 26,862

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 March 31, 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.

	March 31, 2025	December 31, 2024
Credit Facilities	**$ 234,683**	$ 324,346
Unamortized debt issuance costs - Credit Facilities (note 6)	**15,601**	16,861
Long-term notes	**1,930,809**	1,932,890
Unamortized debt issuance costs - Long-term notes (note 7)	**46,235**	47,729
Trade payables	**582,053**	512,473
Share-based compensation liability	**12,602**	24,732
Dividends payable	**17,334**	17,598
Other long-term liabilities	**20,849**	20,887
Cash	**(5,966)**	(16,610)
Trade receivables	**(391,905)**	(387,266)
Prepaids and other assets	**(72,045)**	(76,468)
Net Debt	**$ 2,390,250**	$ 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 March 31	
	2025	2024
Cash flows from operating activities	**$ 431,317**	$ 383,773
Change in non-cash working capital	**29,034**	32,023
Asset retirement obligations settled	**3,519**	6,511
Transaction costs	**—**	1,539
Adjusted Funds Flow	**$ 463,870**	$ 423,846

ABBREVIATIONS

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

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

Mark R. Bly
Chair of the Board

Eric T. Greager
Director

Tiffany (TJ) Thom Cepak [1,3]
Director

Trudy M. Curran [2,4]
Director

Don G. Hrap [1,3]
Director

Angela S. Lekatsas [1,4]
Director

Jennifer A. Maki [1,2]
Director

David L. Pearce [2,3]
Director

Steve D.L. Reynish [3,4]
Director

Jeffrey E. Wojahn [2,4]
Director

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

OFFICERS

Eric T. Greager
President and Chief Executive Officer

Chad L. Kalmakoff
Chief Financial Officer

Chad E. Lundberg
Chief Operating Officer

James R. Maclean
Chief Legal Officer and Corporate Secretary

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

Kendall D. Arthur
Senior Vice President and General Manager, Canadian Heavy Oil Operations

Nicole M. Frechette
Vice President and General Manager, Canadian Light Oil Operations

Taylor J. Young
Vice President and General Manager, Eagle Ford Operations

Chris M.P. Lessoway
Vice President, Finance and Treasurer

HEAD OFFICE

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

Toll-free 1.800.524.5521
T 587.952.3000
F 587.952.3001

BAYTEXENERGY.COM

AUDITORS
KPMG LLP

RESERVES ENGINEERS
McDaniel & Associates Consultants Ltd.

TRANSFER AGENT
Odyssey Trust Company

EXCHANGE LISTINGS
New York Stock Exchange
Toronto Stock Exchange
Symbol: **BTE**

Design: ARTHUR / HUNTER
Printing: Merrill Corporation

BAYTEX

WWW.BAYTEXENERGY.COM