

Baytex Delivers Solid Third Quarter 2025 Results with Record Pembina Duvernay Production and Strong Free Cash Flow

Calgary, Alberta--(Newsfile Corp. - October 30, 2025) - Baytex Energy Corp. (TSX: BTE) (NYSE: BTE) ("Baytex" or the "Company") reports its operating and financial results for the three and nine months ended September 30, 2025 (all amounts are in Canadian dollars unless otherwise noted).

"Baytex delivered solid third-quarter results highlighted by record production in the Pembina Duvernay, strong free cash flow generation, and further progress on debt reduction," said Eric T. Greager, President and Chief Executive Officer. "Our heavy oil business continues to generate reliable returns and, through targeted land acquisitions, we are expanding our long-term inventory. In the Pembina Duvernay, a strategic property swap further consolidates our position, setting the stage for full-scale development. These results reinforce our focus on disciplined capital allocation and demonstrate the quality and value creation potential of our asset base as we work to drive sustainable value for shareholders."

Third Quarter 2025 Highlights

- Delivered production of 150,950 boe/d (86% oil and NGL), a 1% increase in production per basic share compared to Q3/2024.
- Generated free cash flow⁽¹⁾ of \$143 million (\$0.19 per basic share).
- Achieved record Pembina Duvernay production of 10,185 boe/d (77% oil and NGL), up 53% compared to Q2/2025.
- Increased heavy oil production 5% over Q2/2025 with continued strong performance.
- Brought 15.6 net wells to sales in the Eagle Ford with strong execution, achieving a 12% improvement in drilling and completion costs, compared to 2024.
- Expanded our heavy oil development fairway and consolidated Pembina Duvernay acreage through targeted land acquisitions and a property swap.
- Reported cash flows from operating activities of \$473 million (\$0.62 per basic share).
- Generated net income of \$32 million (\$0.04 per basic share).
- Delivered adjusted funds flow⁽²⁾ of \$422 million (\$0.55 per basic share).
- Reduced net debt⁽²⁾ by 2% (\$50 million) and maintained balance sheet strength with a total debt⁽³⁾ to Bank EBITDA⁽³⁾ ratio of 1.1x.

2025 Outlook

We remain committed to disciplined capital allocation, prioritizing free cash flow and strengthening our balance sheet. We continue to execute our 2025 plan and anticipate full-year production of approximately 148,000 boe/d with exploration and development expenditures of approximately \$1.2 billion.

Based on year-to-date actual results and the forward strip for the balance of 2025⁽⁴⁾ we expect to generate free cash flow⁽²⁾ of approximately \$300 million in 2025. We continue to allocate 100% of free cash flow to debt repayment after funding quarterly dividend payments, targeting net debt of approximately \$2.1 billion by year-end.

Our 2026 capital budget will be released in January following approval by our Board of Directors.

(1) 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.

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

(3) Ratio is calculated as total debt on September 30, 2025 divided by EBITDA for the twelve months ended September 30, 2025. Total debt and EBITDA are calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.

(4) Q4/2025 commodity prices: WTI - US\$60/bbl; WCS differential - US\$12/bbl; NYMEX Gas - US\$3.40/MMBtu; Exchange Rate (CAD/USD) - 1.39.

	Three Months Ended			Nine Months Ended	
	September 30, 2025	June 30, 2025	September 30, 2024	September 30, 2025	September 30, 2024
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	\$ 927,648	\$ 886,579	\$ 1,074,623	\$ 2,813,357	\$ 3,191,938
Adjusted funds flow⁽¹⁾	422,232	366,919	537,947	1,253,021	1,494,632
Per share - basic	0.55	0.48	0.68	1.63	1.84
Per share - diluted	0.55	0.48	0.67	1.62	1.84
Free cash flow⁽²⁾	142,688	3,188	220,159	198,405	400,744
Per share - basic	0.19	—	0.28	0.26	0.49
Per share - diluted	0.18	—	0.28	0.26	0.49
Cash flows from operating activities	472,676	354,312	550,042	1,258,305	1,439,399
Per share - basic	0.62	0.46	0.69	1.64	1.78
Per share - diluted	0.61	0.46	0.69	1.63	1.77
Net income	31,968	151,549	185,219	253,108	275,074
Per share - basic	0.04	0.20	0.23	0.33	0.34
Per share - diluted	0.04	0.20	0.23	0.33	0.34
Dividends declared	17,326	17,304	17,732	51,919	54,387
Per share	0.0225	0.0225	0.0225	0.0675	0.0675
Capital Expenditures					
Exploration and development expenditures	\$ 270,364	\$ 356,532	\$ 306,332	\$ 1,031,993	\$ 1,058,456
Acquisitions and divestitures	15,770	468	(394)	15,229	35,638

Total oil and natural gas capital expenditures	\$	286,134	\$	357,000	\$	305,938	\$	1,047,222	\$	1,094,094
Net Debt										
Credit facilities	\$	182,345	\$	333,516	\$	466,108	\$	182,345	\$	466,108
Long-term notes		1,855,605		1,817,707		1,856,869		1,855,605		1,856,869
Total debt ⁽³⁾		2,037,950		2,151,223		2,322,977		2,037,950		2,322,977
Working capital deficiency ⁽²⁾		206,408		142,717		170,292		206,408		170,292
Net debt ⁽¹⁾	\$	2,244,358	\$	2,293,940	\$	2,493,269	\$	2,244,358	\$	2,493,269
Shares Outstanding - basic (thousands)										
Weighted average		768,317		768,717		796,064		769,481		810,589
End of period		768,317		768,317		787,328		768,317		787,328
BENCHMARK PRICES										
Crude oil										
WTI (US\$/bbl)	\$	64.93	\$	63.74		75.10	\$	66.70	\$	77.54
MEH oil (US\$/bbl)		67.03		65.56		77.50		68.65		79.85
MEH oil differential to WTI (US\$/bbl)		2.10		1.82		2.40		1.95		2.31
Edmonton par (\$/bbl)		86.20		84.15		97.91		88.54		98.46
Edmonton par differential to WTI (US\$/bbl)		(2.35)		(2.94)		(3.30)		(3.40)		(5.16)
WCS heavy oil (\$/bbl)		75.14		74.10		83.98		77.80		84.45
WCS differential to WTI (US\$/bbl)		(10.38)		(10.20)		(13.51)		(11.08)		(15.46)
Natural gas										
NYMEX (US\$/MMBtu)	\$	3.07	\$	3.44		2.16	\$	3.39	\$	2.10
AECO (\$/Mcf)		1.00		2.07		0.81		1.70		1.43
CAD/USD average exchange rate		1.3774		1.3840		1.3636		1.3988		1.3603

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			Nine Months Ended		
	September 30, 2025	June 30, 2025	September 30, 2024	September 30, 2025	September 30, 2024	
OPERATING						
Daily Production						
Light oil and condensate (bbl/d)	64,935	62,108	69,843	63,136	67,645	
Heavy oil (bbl/d)	45,269	42,959	42,759	42,825	42,342	
NGL (bbl/d)	19,067	19,948	19,836	19,353	19,767	
Total liquids (bbl/d)	129,271	125,015	132,438	125,314	129,754	
Natural gas (Mcf/d)	130,076	138,482	132,175	134,742	140,069	
Oil equivalent (boe/d @ 6:1) ⁽¹⁾	150,950	148,095	154,468	147,771	153,099	
Adjusted Funds Flow (thousands of Canadian dollars)						
Total sales, net of blending and other expense ⁽²⁾	\$ 877,898	\$ 824,198	\$ 1,022,721	\$ 2,628,406	\$ 3,008,143	
Royalties	(181,230)	(177,390)	(223,800)	(566,557)	(673,411)	
Operating expense	(160,284)	(161,020)	(167,119)	(469,007)	(508,259)	
Transportation expense	(35,295)	(32,907)	(36,883)	(98,714)	(100,032)	
Operating netback ⁽²⁾	\$ 501,089	\$ 452,881	\$ 594,919	\$ 1,494,128	\$ 1,726,441	
General and administrative expense	(20,736)	(22,220)	(17,895)	(68,562)	(61,313)	
Cash interest	(43,873)	(44,875)	(50,109)	(135,535)	(157,335)	
Realized financial derivatives (loss) gain	(8,580)	(11,874)	331	(20,648)	3,562	
Other ⁽³⁾	(5,668)	(6,993)	10,701	(16,362)	(16,723)	
Adjusted funds flow ⁽⁴⁾	\$ 422,232	\$ 366,919	\$ 537,947	\$ 1,253,021	\$ 1,494,632	
Adjusted Funds Flow (per boe)						
Total sales, net of blending and other expense ⁽²⁾	\$ 63.22	\$ 61.16	\$ 71.97	\$ 65.15	\$ 71.71	
Royalties ⁽⁵⁾	(13.05)	(13.16)	(15.75)	(14.04)	(16.05)	
Operating expense ⁽⁵⁾	(11.54)	(11.95)	(11.76)	(11.63)	(12.12)	
Transportation expense ⁽⁵⁾	(2.54)	(2.44)	(2.60)	(2.45)	(2.38)	
Operating netback ⁽²⁾	\$ 36.09	\$ 33.61	\$ 41.86	\$ 37.03	\$ 41.16	
General and administrative expense ⁽⁵⁾	(1.49)	(1.65)	(1.26)	(1.70)	(1.46)	
Cash interest ⁽⁵⁾	(3.16)	(3.33)	(3.53)	(3.36)	(3.75)	
Realized financial derivatives (loss) gain ⁽⁵⁾	(0.62)	(0.88)	0.02	(0.51)	0.08	
Other ⁽³⁾⁽⁵⁾	(0.42)	(0.52)	0.76	(0.40)	(0.40)	
Adjusted funds flow	\$ 30.40	\$ 27.23	\$ 37.85	\$ 31.06	\$ 35.63	

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 recovery or expense and cash share-based compensation. Refer to the Q3/2025 MD&A for further information on these amounts.
(4) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(5) Calculated as royalties, operating expense, transportation expense, general and administrative expense, cash interest, realized financial derivatives gain or loss, or other, divided by barrels of oil equivalent production volume for the applicable period.

Financial Results

During the third quarter, we delivered operating and financial results in line with our full-year plan. Adjusted funds flow⁽¹⁾ was

\$422 million (\$0.55 per basic share) and net income was \$32 million (\$0.04 per basic share).

We generated free cash flow⁽²⁾ of \$143 million and returned \$17 million to shareholders through our quarterly dividend.

Net debt⁽¹⁾ decreased 2% (\$50 million) to \$2.2 billion, driven by strong free cash flow, partially offset by an unrealized foreign exchange loss from a weakening Canadian dollar on our U.S. dollar-denominated debt.

We maintain strong financial flexibility with US\$1.1 billion in credit facilities that mature in June 2029 and are less than 15% drawn, positioning us well across various commodity price cycles.

Operations

Production averaged 150,950 boe/d (86% oil and NGL) in the third quarter, representing a 1% increase in production per basic share compared to Q3/2024. Consistent with our full-year plan, exploration and development expenditures for Q3/2025 totaled \$270 million and we brought 69 (61.6 net) wells onstream.

Oil-Focused Eagle Ford Development

Eagle Ford production averaged 82,765 boe/d (82% oil and NGL), relatively unchanged from Q2/2025. Crude oil production averaged 52,330 bbl/d, up 3% from Q2/2025.

Our 2025 development program has largely focused on the black oil to condensate windows of our acreage. We brought 15.6 net wells onstream while achieving a 12% improvement in operated drilling and completion costs per completed lateral foot compared to 2024.

During the second quarter we successfully completed two refracs in the Lower Eagle Ford. The wells continue to deliver results comparable to our broader development program with improved capital efficiencies and returns. We anticipate an expanded refrac program in 2026.

Record Pembina Duvernay Production

Production from our Canadian light oil business averaged 19,589 boe/d (80% oil and NGL), up 20% from Q2/2025. The Pembina Duvernay represents our largest growth asset and accounted for approximately 50% of Canadian light oil production during the quarter.

We achieved record Pembina Duvernay production of 10,185 boe/d (77% oil and NGL) in Q3/2025, up 53% from Q2/2025. The third pad (10-31, 3 wells) from our 2025 program was brought onstream in September with two of three wells generating strong 30-day peak production rates averaging 1,380 boe/d per well (830 bbl/d of crude oil, 355 bbl/d of NGLs, 1,172 Mcf/d of natural gas). The third well encountered casing issues during completion and was subsequently abandoned.

Our 2025 program (3 pads, 8 producing wells) exceeded initial rate expectations and sets the stage for full commercialization. Strong production, combined with an 11% improvement in drilling and completion costs per completed lateral foot compared to 2024, has significantly improved well economics.

We have assembled 140 net sections of highly prospective lands and identified approximately 200 drilling locations. Over the next two years, we expect to transition to a one-rig drilling program with 18 to 20 wells per year, targeting production of 20,000-25,000 boe/d by 2029-2030.

Subsequent to quarter-end, we completed an asset swap in the Pembina Duvernay consolidating our southern acreage. This enables more efficient development of these lands commencing in 2026. In addition, in support of our ongoing development, we commissioned midstream infrastructure associated with our partnership with Gibson Energy. Construction of the infrastructure was completed on time and under budget.

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

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

Organic Heavy Oil Growth and Inventory Expansion

Heavy oil production averaged 47,280 boe/d (96% oil and NGL), up 5% from Q2/2025. Strong operating results reflect continued performance at Peavine, Peace River, and across the broader Mannville group in Lloydminster. We brought onstream 20.0 net wells during the quarter: 10 Clearwater wells at Peavine, 4 wells at Peace River, and 6 wells at Lloydminster.

We continue to build on our heavy oil expertise and enhance our long-term inventory of development prospects. During the quarter, we acquired 40.5 net sections of highly prospective lands at Peace River, and 4.5 net sections in northeast Alberta targeting the broader Mannville group.

To-date in 2025, through organic development and land acquisitions, we have added 200 drilling locations to our inventory count, bringing our heavy oil portfolio to 1,100 drilling locations. This supports approximately 10 years of drilling at our current pace of development.

Our heavy oil operations continue to deliver the strongest economic returns across our portfolio, supported by our extensive

acreage, capital-efficient development, and the continued strength in Western Canadian Select pricing.

Quarterly Dividend

The Board of Directors has declared a quarterly cash dividend of \$0.0225 per share, payable January 2, 2026 to shareholders of record on December 15, 2025.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and nine months ended September 30, 2025 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR+ at www.sedarplus.ca and EDGAR at www.sec.gov/edgar.shtml.

Conference Call Tomorrow

9:00 a.m. MT (11:00 a.m. ET)

Baytex will host a conference call tomorrow, October 31, 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=HLPhYJ02> 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: that we are working to drive sustainable value for shareholders; we are focused on disciplined capital allocation, prioritizing free cash flow, and strengthening our balance sheet; for 2025: our guidance for exploration and development expenditures, production and the amount of free cash flow we expect to generate and its expected allocation as between debt reduction and dividend payments; our targeted net debt at year-end 2025; the expected release date for our 2026 capital budget; the opportunity for an expanded 2026 refrac program; that our Pembina Duvernay lands are highly prospective, that we will transition to a one-rig program drilling 18-20 wells per year over the next two years and our targeted production of 25,000 boe/d by 2029-2030; and the number of years of drilling activity our heavy oil portfolio supports. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy crude oil prices; well production rates and reserve volumes; success obtained in drilling new wells; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; operating costs; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; our ability to market oil and natural gas successfully; that we will have sufficient financial resources in the future to provide shareholder returns; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

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

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

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2024 filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings. The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

This press release contains information that may be considered a financial outlook under applicable securities laws about the Company's potential financial position, including, but not limited to, our 2025 guidance for development expenditures; our expected 2025 free cash flow; and our intentions regarding the allocating our annual free cash flow; all of

which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Company and the resulting financial results will vary from the amounts set forth in this press release and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Company undertakes no obligation to update such financial outlook, whether as a result of new information, future events or otherwise. The financial outlook contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about the Company's potential future business operations. Readers are cautioned that the financial outlook contained in this press release is not conclusive and is subject to change.

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

Specified Financial Measures

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

Non-GAAP Financial Measures

Total sales, net of blending and other expense

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

Operating netback

Operating netback and operating netback after financial derivatives are used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales less blending and other 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.

(\$ thousands)	Three Months Ended			Nine Months Ended		
	September 30, 2025	June 30, 2025	September 30, 2024	September 30, 2025	September 30, 2024	September 30, 2024
Petroleum and natural gas sales	\$ 927,648	\$ 886,579	\$ 1,074,623	\$ 2,813,357	\$ 3,191,938	\$ 3,191,938
Blending and other expense	(49,750)	(62,381)	(51,902)	(184,951)	(183,795)	(183,795)
Total sales, net of blending and other expense	\$ 877,898	\$ 824,198	\$ 1,022,721	\$ 2,628,406	\$ 3,008,143	\$ 3,008,143
Royalties	(181,230)	(177,390)	(223,800)	(566,557)	(673,411)	(673,411)
Operating expense	(160,284)	(161,020)	(167,119)	(469,007)	(508,259)	(508,259)
Transportation expense	(35,295)	(32,907)	(36,883)	(98,714)	(100,032)	(100,032)
Operating netback	\$ 501,089	\$ 452,881	\$ 594,919	\$ 1,494,128	\$ 1,726,441	\$ 1,726,441
Realized financial derivatives (loss) gain ⁽¹⁾	(8,580)	(11,874)	331	(20,648)	3,562	3,562
Operating netback after realized financial derivatives	\$ 492,509	\$ 441,007	\$ 595,250	\$ 1,473,480	\$ 1,730,003	\$ 1,730,003

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss. See the Financial Instruments and Risk Management note within the consolidated financial statements for the respective period end for further information.

Free cash flow

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

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

(\$ thousands)	Three Months Ended			Nine Months Ended		
	September 30, 2025	June 30, 2025	September 30, 2024	September 30, 2025	September 30, 2024	September 30, 2024
Cash flows from operating activities	\$ 472,676	\$ 354,312	\$ 550,042	\$ 1,258,305	\$ 1,439,399	\$ 1,439,399
Change in non-cash working capital	(55,961)	9,042	(20,813)	(17,885)	31,350	31,350
Additions to exploration and evaluation assets	—	(930)	—	(930)	—	—
Additions to oil and gas properties	(270,364)	(355,602)	(306,332)	(1,031,063)	(1,058,456)	(1,058,456)
Payments on lease obligations	(3,663)	(3,634)	(2,738)	(10,022)	(13,088)	(13,088)
Transaction costs	—	—	—	—	1,539	1,539
Free cash flow	\$ 142,688	\$ 3,188	\$ 220,159	\$ 198,405	\$ 400,744	\$ 400,744

Working capital deficiency

Working capital deficiency is calculated as cash, trade receivables, and prepaids and other assets net of trade payables, share-based compensation liability, dividends payable, and other long-term liabilities. Working capital deficiency is used by management to measure the Company's liquidity. At September 30, 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.

(\$ thousands)	As at		
	September 30, 2025	June 30, 2025	September 30, 2024
Cash	\$ (10,417)	\$ (7,156)	\$ (21,311)
Trade receivables	(324,287)	(363,507)	(375,942)
Prepaids and other assets	(75,100)	(75,856)	(78,427)
Trade payables	554,057	538,330	584,696
Share-based compensation liability	24,666	13,851	23,962
Dividends payable	17,326	17,304	17,732
Other long-term liabilities	20,163	19,751	19,582
Working capital deficiency	\$ 206,408	\$ 142,717	\$ 170,292

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.

(\$ thousands)	As at			
	September 30, 2025		June 30, 2025	
				September 30, 2024
Credit facilities	\$	166,841	\$	317,310
Unamortized debt issuance costs - Credit facilities ⁽¹⁾		15,504		16,206
Long-term notes		1,815,230		1,776,647
Unamortized debt issuance costs - Long-term notes ⁽¹⁾		40,375		41,060
Trade payables		554,057		538,330
Share-based compensation liability		24,666		13,851
Dividends payable		17,326		17,304
Other long-term liabilities		20,163		19,751
Cash		(10,417)		(7,156)
Trade receivables		(324,287)		(363,507)
Prepaids and other assets		(75,100)		(75,856)
Net debt	\$	2,244,358	\$	2,293,940

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

Adjusted funds flow

Adjusted funds flow is used to monitor operating performance and our ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, 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				Nine Months Ended	
(\$ thousands)	September 30, 2025	June 30, 2025	September 30, 2024	September 30, 2025	September 30, 2024	
Cash flow from operating activities	\$ 472,676	\$ 354,312	550,042	\$ 1,258,305	\$ 1,439,399	
Change in non-cash working capital	(55,961)	9,042	(20,813)	(17,885)	31,350	
Asset retirement obligations settled	5,517	3,565	8,718	12,601	22,344	
Transaction costs	—	—	—	—	1,539	
Adjusted funds flow	\$ 422,232	\$ 366,919	\$ 537,947	\$ 1,253,021	\$ 1,494,632	

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.

This presentation discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's total proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. In the Duvernay, Baytex's net drilling locations include 42 proved and 20 probable locations as at December 31, 2024 and 153 unbooked locations. In the heavy oil business unit, Baytex's net drilling locations include 149 proved and 112 probable locations as at December 31, 2024 and 839 unbooked locations.

Throughout this press release, "oil and NGL" refers to heavy crude oil, bitumen, light and medium crude oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and nine months ended September 30, 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 September 30, 2025					Three Months Ended September 30, 2024				
Heavy	Light	NGL	Natural	Oil	Heavy	Light	NGL	Natural	Oil

	Crude Oil (bbl/d)	and Medium Crude Oil (bbl/d)	(bbl/d)	Gas (Mcf/d)	Equivalent (boe/d)	Crude Oil (bbl/d)	and Medium Crude Oil (bbl/d)	(bbl/d)	Gas (Mcf/d)	Equivalent (boe/d)
Canada - Heavy										
Peace River	9,900	13	38	10,079	11,631	9,024	13	36	11,959	11,067
Lloydminster	13,260	26	1	1,224	13,491	12,792	19	—	1,659	13,088
Peavine	20,953	—	—	—	20,953	20,085	—	—	—	20,085
Remaining Properties	1,094	3	—	648	1,205	846	1	—	494	929
Canada - Light										
Viking	56	7,500	210	9,832	9,404	—	9,328	183	9,152	11,036
Duvernay	—	4,824	3,068	13,758	10,185	—	4,019	2,276	7,529	7,550
Remaining Properties	6	239	168	5,420	1,316	12	401	38	2,773	913
United States										
Eagle Ford	—	52,330	15,582	89,115	82,765	—	56,062	17,303	98,609	89,800
Total	45,269	64,935	19,067	130,076	150,950	42,759	69,843	19,836	132,175	154,468

	Nine Months Ended September 30, 2025					Nine Months Ended September 30, 2024				
	Heavy Crude Oil (bbl/d)	Light and Medium Crude Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Crude Oil (bbl/d)	Light and Medium Crude Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada - Heavy										
Peace River	9,805	13	30	9,850	11,490	9,206	10	41	10,931	11,079
Lloydminster	12,362	20	—	1,188	12,580	13,211	16	—	1,566	13,488
Peavine	19,455	—	—	—	19,455	19,211	—	—	—	19,211
Remaining Properties	1,113	2	—	687	1,229	706	32	—	344	795
Canada - Light										
Viking	85	8,015	187	10,302	10,004	—	8,881	185	10,264	10,776
Duvernay	—	3,478	2,488	9,485	7,547	—	2,782	1,892	6,291	5,723
Remaining Properties	5	324	494	10,823	2,627	8	402	373	9,766	2,411
United States										
Eagle Ford	—	51,284	16,154	92,407	82,839	—	55,522	17,276	100,907	89,616
Total	42,825	63,136	19,353	134,742	147,771	42,342	67,645	19,767	140,069	153,099

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:

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