Baytex Reports Strong Canadian Reserves Growth and Positive Operational Momentum

Calgary, Alberta--(Newsfile Corp. - February 2, 2026) - Baytex Energy Corp. (TSX: BTE) (NYSE: BTE) ("Baytex") is pleased to announce its year-end 2025 reserves and provide an operations update (all amounts in Canadian dollars unless otherwise noted).

Our 2025 performance was highlighted by the strategic divestiture of our U.S. assets, resulting in a significantly strengthened financial position and sharpened focus on our high-return Canadian energy platform. We entered 2026 with a net cash position and remain committed to returning a significant portion of the net proceeds from the U.S. sale (after debt repayment) to shareholders.

Baytex is also providing an update on its 2025 consolidated operations, including U.S. assets up to the December 19, 2025 sale closing. Consolidated production averaged 137,087 boe/d (84% oil and NGL) in the fourth quarter, with annual 2025 production of 145,079 boe/d (85% oil and NGL). Exploration and development expenditures totaled $175 million during the fourth quarter and $1,207 million in 2025.

Production in Canada averaged 67,295 boe/d (88% oil and NGL) in the fourth quarter, with annual 2025 production of 65,528 boe/d (89% oil and NGL), representing a 6% growth rate compared to 2024 (excluding non-core divestitures). For 2026, we are targeting annual production of 67,000 to 69,000 boe/d with exploration and development expenditures of $550 to $625 million.

Year-End 2025 Reserves Highlights Value Creation - Canada

In Canada, we invested $549 million on exploration and development expenditures in a highly capital efficient program. Our Pembina Duvernay and heavy oil development contributed significantly to our year-end 2025 reserves, demonstrating the long-term resiliency and sustainability of our business and its capacity for future value creation.

We achieved solid reserves growth in Canada across all three reserves categories, proved developed producing ("PDP"), proved ("1P") and proved plus probable ("2P").

- PDP reserves increased 12% to 69 MMboe (61 MMboe at year-end 2024), replacing 133% of production.
- 1P reserves increased 15% to 151 MMboe (131 MMboe at year-end 2024), replacing 185% of production.
- 2P reserves increased 9% to 282 MMboe (259 MMboe at year-end 2024), replacing 203% of production.
- Finding and development ("F&D") costs, including changes in future development costs ("FDC") were $17.28/boe for PDP reserves, $16.39/boe for 1P reserves and $16.27/boe for 2P reserves.
- We generated a strong PDP F&D recycle ratio of 2.0x and a 1P and 2P F&D recycle ratio of 2.1x based on a 2025 operating netback(1) of $34.61/boe, reflective of the efficiency of our capital program.
- We maintain a robust reserves life index of 11.5 years based on 2P reserves.

Our 2025 reserves report continues a strong track record of value creation in Canada.

- Our three-year average (2023-2025) production replacement, excluding acquisitions and divestitures, for PDP, 1P, and 2P reserves is 119%, 151% and 169%, respectively.
- Our three-year average (2023-2025) F&D costs, including changes in FDC were $18.12/boe for PDP reserves, $18.74/boe for 1P reserves and $19.76/boe for 2P reserves.
- We generated a strong three-year average (2023-2025) F&D recycle ratio of 2.1x for PDP reserves, 2.0x for 1P reserves, and 1.9x for 2P reserves.

(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.

Operations Update - Driving Performance in Our Canadian Portfolio

We are building on the operational momentum established last year with a 2026 plan that targets 3% to 5% annual production growth while investing in long-term infrastructure, exploration and land to support future growth and inventory expansion.

In the Duvernay, production is expected to increase 35% to average approximately 11,000 boe/d in 2026, with a target year-end exit rate of 14,000 to 15,000 boe/d. We currently have one rig running in the Duvernay, drilling the first well of a four-well pad on our southern acreage. Completion operations are scheduled for the second quarter with the wells expected to be onstream by mid-year. The remaining two pads (4-wells each) are expected to be onstream during the third and fourth quarter. We have also commenced our infrastructure build-out for 2026, including anchor oil batteries and water handling.

Our heavy oil portfolio is expected to deliver stable production and reliable returns. We currently have five drilling rigs active across our heavy oil fairway targeting the Clearwater at Peavine and the broader Mannville stack in Lloydminster. We expect to bring 91 heavy oil wells onstream in 2026. In addition, our 2026 program will see increased exploration activity, including stratigraphic tests, step-out wells and 3-D seismic.

At Peavine, we are drilling the third of thirteen multi-lateral horizontal wells on a single pad. In addition, we intend to undertake two waterflood pilot projects as we look to blend the attractive capital efficiencies of multi-lateral primary development with the potential upside of enhanced recovery and moderated decline rates.

At Lloydminster, our first quarter drilling program will target seven discrete horizons in the Mannville: Cummings, GP, Lloydminster, McLaren, Sparky and both the Upper and Lower Waseca. In northeast Alberta, we recently brought onstream two multi-lateral wells in the Sparky that generated average 30-day initial production rates of 450 bbl/d per well, and a five-well pad in the Upper Waseca that generated average 30-day initial production rates of 150 bbl/d per well.

In the Viking, we are running a largely level-loaded one rig program in 2026 (outside of spring break-up) to maximize efficiencies. We expect to bring 73 net wells onstream in 2026.

Strong Net Cash Position and Shareholder Returns

In December, we repaid our outstanding credit facilities, redeemed all of the US$759 million principal amount of 8.500% Senior Notes due 2030 and US$505 million principal amount of 7.375% Senior Notes due 2032 (of an original US$575 million principal amount outstanding) through a successful tender offer.

We entered 2026 with a net cash position (cash less principal amount of Senior Notes that remain outstanding) of approximately $857 million that provides significant financial flexibility. We intend to return a significant portion to shareholders, prioritizing share buybacks while maintaining our current annual dividend of $0.09 per share.

Our Normal Course Issuer Bid ("NCIB") allows Baytex to purchase up to 66.2 million common shares during the 12-month period ending July 1, 2026. On December 24, 2025, we re-initiated our share buyback program. To-date (through January 30, 2026) we have repurchased 17.1 million common shares for $78 million, representing 2.2% of our shares outstanding, at an average price of $4.55 per share.

Disciplined Risk Management

We employ a disciplined hedging strategy to manage heavy oil basis differential volatility. For 2026, approximately 45% of our net heavy oil basis differential exposure is hedged at a WTI-WCS basis differential of US$13.13/bbl.

We also have WTI hedges in place for the first half of 2026. For Q1/2026 we have entered into hedges on approximately 60% of our net crude oil exposure utilizing two-way collars with an average floor price of US$60/bbl and an average ceiling price of US$67/bbl. For Q2/2026 we have entered into hedges on approximately 50% of our net crude oil exposure utilizing two-way collars with an average floor price of US$60/bbl and an average ceiling price of US$66/bbl.

Year-End 2025 Results

Baytex expects to release its year-end 2025 operating and financial results on March 4, 2026.

Year-End 2025 Reserves

Baytex's year-end 2025 reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent qualified reserves evaluator. All of our oil and gas properties were evaluated in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants ("GLJ") and Sproule ERCE ("Sproule") as of January 1, 2026.

Additional information regarding Baytex's reserves and other oil and gas information will be included in Baytex's Annual Information Form for the year ended December 31, 2025, which is expected to be filed on SEDAR+ and EDGAR on or around March 4, 2026.

The following table sets forth our gross and net reserves volumes at December 31, 2025 by product type and reserves category. Please note that the data in the table may not add due to rounding.

Reserves Summary

Reserves Summary	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids [3] (Mbbls)	Conventional Natural Gas [4] (MMcf)	Shale Gas (MMcf)	Total [5] (Mboe)
Gross [1]									
Proved producing	8,466	4,256	38,513	-	51,235	7,003	46,117	18,277	68,970
Proved developed non-producing	-	-	993	-	993	1	236	-	1,033
Proved undeveloped	11,252	18,464	19,254	-	48,970	17,815	28,428	55,041	80,696
Total proved	19,718	22,719	58,760	-	101,197	24,819	74,780	73,318	150,699
Total probable	12,817	10,062	41,149	44,459	108,487	10,837	39,115	32,051	131,185
Proved plus probable	32,535	32,781	99,909	44,459	209,684	35,657	113,896	105,369	281,884
Net [2]									

Proved producing	8,029	3,593	33,045	-	44,666	6,115	41,598	16,663	60,492
Proved developed non-producing	-	-	868	-	868	1	219	-	905
Proved undeveloped	10,735	15,798	17,184	-	43,718	15,577	24,806	49,697	71,712
Total proved	18,764	19,391	51,097	-	89,252	21,694	66,623	66,360	133,109
Total probable	11,876	8,065	34,599	35,743	90,282	9,129	34,047	28,442	109,826
Proved plus probable	30,640	27,455	85,696	35,743	179,534	30,823	100,670	94,801	242,936

Notes:

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others plus royalty interest reserves.
(3) Natural Gas Liquids includes condensate.
(4) Conventional Natural Gas includes associated, non-associated and solution gas.
(5) 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.

Reserves Reconciliation - Canada

The following table reconciles the year-over-year changes in our Canadian gross reserves volumes by product type and reserves category. Please note that the data in the table may not add due to rounding.

Proved Reserves - Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (2) (Mbbls)	Conventional Natural Gas (3) (MMcf)	Shale Gas (MMcf)	Total (4) (Mboe)
December 31, 2024	23,604	15,935	55,357	-	94,896	15,797	74,789	48,640	131,265
Extensions	982	7,853	14,174	-	23,008	8,994	13,463	26,434	38,652
Technical Revisions	(664)	406	6,488	-	6,231	1,562	1,854	2,590	8,533
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(355)	-	(147)	-	(502)	(66)	(1,442)	-	(809)
Economic Factors	(950)	(104)	(1,503)	-	(2,557)	(140)	(1,830)	(395)	(3,068)
Production	(2,900)	(1,371)	(15,608)	-	(19,879)	(1,328)	(12,054)	(3,951)	(23,874)
December 31, 2025	19,718	22,719	58,760	-	101,197	24,819	74,780	73,318	150,699

Probable Reserves - Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (2) (Mbbls)	Conventional Natural Gas (3) (MMcf)	Shale Gas (MMcf)	Total (4) (Mboe)
December 31, 2024	13,644	11,406	34,190	44,489	103,729	11,400	38,344	37,041	127,692
Extensions	89	(1,559)	10,144	-	8,673	(944)	6,534	(4,694)	8,035
Technical Revisions	(1,042)	291	(2,996)	-	(3,747)	493	(5,191)	(22)	(4,122)
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(332)	-	(256)	-	(587)	(33)	(700)	-	(737)
Economic Factors	458	(76)	67	(30)	419	(78)	129	(273)	317
Production	-	-	-	-	-	-	-	-	-
December 31, 2025	12,817	10,062	41,149	44,459	108,487	10,837	39,115	32,051	131,185

Proved Plus Probable Reserves - Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (2) (Mbbls)	Conventional Natural Gas (3) (MMcf)	Shale Gas (MMcf)	Total (4) (Mboe)
December 31, 2024	37,248	27,341	89,547	44,489	198,625	27,197	113,133	85,680	258,957
Extensions	1,070	6,293	24,317	-	31,681	8,050	19,997	21,740	46,687
Technical Revisions	(1,706)	698	3,492	-	2,484	2,055	(3,337)	2,568	4,411
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions	(687)	-	(403)	-	(1,090)	(99)	(2,142)	-	(1,546)
Economic Factors	(491)	(180)	(1,436)	(30)	(2,137)	(219)	(1,701)	(668)	(2,751)
Production	(2,900)	(1,371)	(15,608)	-	(19,879)	(1,328)	(12,054)	(3,951)	(23,874)
December 31, 2025	32,535	32,781	99,909	44,459	209,684	35,657	113,896	105,369	281,884

Notes:

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
(2) Natural gas liquids includes condensate.
(3) Conventional natural gas includes associated, non-associated and solution gas.
(4) 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.

Reserves Reconciliation - Total Company

The following table reconciles the year-over-year changes in our gross reserves volumes by product type and reserves category. Please note that the data in the table may not add due to rounding.

Proved Reserves - Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (2) (Mbbls)	Conventional Natural Gas (3) (MMcf)	Shale Gas (MMcf)	Total (4) (Mboe)
December 31, 2024	23,604	168,200	55,357	-	247,161	91,923	74,789	339,775	408,177
Extensions	982	8,864	14,174	-	24,019	9,390	13,463	28,378	40,383
Technical Revisions	(664)	406	6,488	-	6,231	1,562	1,854	2,590	8,533
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions (5)	(355)	(135,842)	(147)	-	(136,344)	(70,493)	(1,442)	(260,036)	(250,417)
Economic Factors	(950)	(104)	(1,503)	-	(2,557)	(140)	(1,830)	(395)	(3,068)
Production (6)	(2,900)	(18,805)	(15,608)	-	(37,313)	(7,423)	(12,054)	(36,994)	(52,910)
December 31, 2025	19,718	22,719	58,760	-	101,197	24,819	74,780	73,318	150,699

Probable Reserves - Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (2) (Mbbls)	Conventional Natural Gas (3) (MMcf)	Shale Gas (MMcf)	Total (4) (Mboe)
December 31, 2024	13,644	84,798	34,190	44,489	177,121	42,813	38,344	152,995	251,824
Extensions	89	(2,571)	10,144	-	7,661	(1,340)	6,534	(6,638)	6,304
Technical Revisions	(1,042)	291	(2,996)	-	(3,747)	493	(5,191)	(22)	(4,122)
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions (5)	(332)	(72,381)	(256)	-	(72,968)	(31,051)	(700)	(114,010)	(123,137)
Economic Factors	458	(76)	67	(30)	419	(78)	129	(273)	317
Production (6)	-	-	-	-	-	-	-	-	-
December 31, 2025	12,817	10,062	41,149	44,459	108,487	10,837	39,115	32,051	131,185

Proved Plus Probable Reserves - Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids (2) (Mbbls)	Conventional Natural Gas (3) (MMcf)	Shale Gas (MMcf)	Total (4) (Mboe)
December 31, 2024	37,248	252,997	89,547	44,489	424,281	134,736	113,133	492,770	660,001
Extensions	1,070	6,293	24,317	-	31,681	8,050	19,997	21,740	46,687
Technical Revisions	(1,706)	698	3,492	-	2,484	2,055	(3,337)	2,568	4,411
Acquisitions	-	-	-	-	-	-	-	-	-
Dispositions (5)	(687)	(208,223)	(403)	-	(209,313)	(101,544)	(2,142)	(374,047)	(373,554)
Economic Factors	(491)	(180)	(1,436)	(30)	(2,137)	(219)	(1,701)	(668)	(2,751)
Production (6)	(2,900)	(18,805)	(15,608)	-	(37,313)	(7,423)	(12,054)	(36,994)	(52,910)
December 31, 2025	32,535	32,781	99,909	44,459	209,684	35,657	113,896	105,369	281,884

Notes:

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
(2) Natural gas liquids includes condensate.
(3) Conventional natural gas includes associated, non-associated and solution gas.
(4) 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.
(5) Dispositions includes the sale of Baytex's U.S. assets on December 19, 2025.
(6) Production includes Baytex's U.S. assets to December 19, 2025.

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserves categories noted below.

Future Development Costs ($ millions)	Proved Reserves	Proved Plus Probable Reserves
2026	359	442
2027	505	618
2028	511	694
2029	343	657
2030	146	248
Remainder	51	773
Total FDC undiscounted	1,915	3,432

Efficiency of Capital Development Program - Canada

Based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel, the efficiency of our Canadian exploration and development program is summarized in the following table.

	2025	2024	2023	3 Year
Proved Developed Producing Reserves				
Exploration and development expenditures ($ millions)	548.4	489.5	463.2	1,501.0
Reserves additions (MMboe) (1)	31.7	26.8	24.3	82.9
F&D costs ($/boe) (2)	17.28	18.25	19.06	18.12
Production replacement (3)	133%	115%	109%	119%
Recycle ratio (4)	2.0x	2.2x	2.0x	2.1x
Proved Reserves				
Exploration and development expenditures ($ millions)	548.4	489.5	463.2	1,501.0
Change in future development costs ($ millions)	174.5	238.5	60.3	473.3
Total F&D capital ($ millions)	722.9	728.0	523.5	1,974.3
Reserves additions (MMboe) (1)	44.1	39.1	22.1	105.3
F&D costs ($/boe) (2)	16.39	18.60	23.70	18.74
Production replacement (3)	185%	167%	99%	151%
Recycle ratio (4)	2.1x	2.1x	1.6x	2.0x
Proved Plus Probable Reserves				
Exploration and development expenditures ($ millions)	548.4	489.5	463.2	1,501.0
Change in future development costs ($ millions)	238.4	336.3	252.6	827.3
Total F&D capital ($ millions)	786.7	825.8	715.8	2,328.3
Reserves additions (MMboe) (1)	48.3	40.4	29.1	117.8
F&D costs ($/boe) (2)	16.27	20.43	24.61	19.76
Production replacement (3)	203%	173%	130%	169%
Recycle ratio (4)	2.1x	1.9x	1.6x	1.9x

Notes:

(1) Reserves additions includes extensions, technical revisions and economic factors.
(2) F&D costs are calculated on a per boe basis by dividing the aggregate of the change in FDC from the prior year for the particular reserves category and the costs incurred on E&D activities in the year by the change in reserves from the prior year for the reserve category.
(3) Production replacement is calculated by dividing reserves additions by annual production.
(4) Recycle ratio is calculated by dividing operating netback on a per boe basis by F&D costs.

Forecast Prices and Costs

The following table summarizes the forecast prices used in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2025. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of McDaniel, GLJ and Sproule as of January 1, 2026.

Year	WTI Crude Oil US$/bbl	Edmonton Light Crude Oil $/bbl	Western Canadian Select $/bbl	Henry Hub US$/MMbtu	AECO Spot $/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2025 act.	65.50	85.65	75.05	3.55	1.85	2.1	0.720
2026	59.92	77.54	65.13	3.74	3.00	-	0.730
2027	65.10	83.60	70.43	3.78	3.30	2.0	0.740
2028	70.28	90.17	76.90	3.85	3.49	2.0	0.740
2029	71.93	92.32	78.71	3.93	3.58	2.0	0.740
2030	73.37	94.17	80.29	4.01	3.65	2.0	0.740
2031	74.84	96.06	81.90	4.09	3.72	2.0	0.740
2032	76.34	97.98	83.53	4.17	3.80	2.0	0.740
2033	77.87	99.93	85.20	4.26	3.88	2.0	0.740
2034	79.42	101.93	86.91	4.34	3.95	2.0	0.740
2035	81.01	103.97	88.65	4.43	4.03	2.0	0.740
Thereafter		Escalation rate of 2.0%				2.0	0.740

Net Present Value of Reserves (1) (Forecast Prices and Costs)

The following table summarizes the McDaniel estimate of the net present value before income taxes of the future net revenue attributable to our reserves.

Reserves at December 31, 2025 ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	141	647	729	725
Proved developed non-producing	28	21	17	13
Proved undeveloped	1,204	801	538	359
Total proved	1,373	1,469	1,283	1,097
Probable	3,419	1,952	1,258	879
Total Proved Plus Probable (before tax)	4,792	3,420	2,541	1,976

Note:

(1) Includes abandonment, decommissioning and reclamation costs for all producing and non-producing wells and facilities.

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 have a high return energy platform; we are committed to returning a significant portion of the net proceeds from the U.S. sale to shareholders, prioritizing share buybacks and maintaining an annual dividend of $0.09 per share; our expected 2026 full-year production volumes and exploration and development expenditures; our 2026 plan targets 3-6% production growth, and investment in long-term infrastructure, exploration and land to support future growth and inventory expansion; for 2026 in the Duvernay, our expected production growth and exit production rate, and plans related to drilling, completion and on-streaming of wells and plans related to our infrastructure build out; for 2026 in Heavy oil, our plans with respect to drilling and exploration activity including our intention to undertake two waterflood pilots at Peavine and target seven discrete zones in the Mannville at Lloydminster; for 2026 in the Viking our plans with respect to drilling and bringing wells on-stream; the expected release date of our year-results; future development costs, F&D and FD&A; forecast prices for oil and natural gas; forecast inflation and exchange rates; and the net present value before income taxes of the future net revenue attributable to our reserves. 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 and the volatility of oil and natural gas prices and price differentials; 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 production guidance, exploration and development expenditures guidance; 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; 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; conflicts of interest between the Corporation 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 NCIB), 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 Corporation'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 Corporation has incurred or may incur in the future, including the terms of the Credit Facilities) and satisfaction of the solvency tests imposed on the Corporation under applicable corporate law. There can be no assurance of the number of Common Shares that the Corporation will acquire pursuant to a share buyback, if any, in the future. Further, the payment of dividends to shareholders is not assured or guaranteed and dividends may be reduced or suspended entirely.

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2025, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission on or around March 4, 2026 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 Corporation's potential financial position, including, but not limited to: our 2026 guidance for development expenditures and our intention to allocate cash to shareholder returns through a share buyback and a dividend; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Corporation 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 Corporation 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 Corporation'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 operating netback, which is a financial measure that does not have any standardized meaning prescribed by IFRS. While this measure is commonly used in the oil and gas industry, our determination of this measure may not be comparable with calculations of similar measures presented by other reporting issuers.

Non-GAAP Financial Ratios

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.

Advisory Regarding Oil and Gas Information

The reserves information contained in this press release has been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2025, which is expected to be filed on March 4, 2026. Listed below are cautionary statements that are specifically required by NI 51-101:

- *The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one boe (6 mcf/bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.*
- *With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.*
- *This press release contains estimates of the net present value of our future net revenue from our reserves. Such*

amounts do not represent the fair market value of our reserves.

This press release discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. In the Duvernay, Baytex's net drilling locations include 58 proved and 11 probable locations as at December 31, 2025 and 141 unbooked locations. In the Viking, Baytex's net drilling locations include 457 proved and 196 probable locations as at December 31, 2025 and 263 unbooked locations. In the heavy oil business unit, Baytex's net drilling locations include 160 proved and 167 probable locations as at December 31, 2025 and 773 unbooked locations.

Throughout this press release, "oil and NGL" refers to heavy oil, bitumen, light and medium 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 twelve months ended December 31, 2025. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas.

	Three Months Ended December 31, 2025					Twelve Months Ended December 31, 2025				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada - Heavy										
Peace River	9,493	8	35	8,974	11,032	9,726	12	32	9,629	11,374
Lloydminster	13,702	16	1	1,465	13,963	12,700	19	-	1,258	12,928
Peavine	18,582	-	-	-	18,582	19,235	-	-	-	19,235
Remaining Properties	802	3	-	660	915	1,034	2	-	680	1,150
Canada - Light										
Viking	40	7,213	259	9,388	9,076	74	7,813	205	10,071	9,771
Duvernay	-	4,585	3,594	14,801	10,645	-	3,757	2,767	10,825	8,328
Remaining Properties	9	206	599	13,607	3,082	6	294	520	11,525	2,742
Total Canada	42,628	12,031	4,488	48,895	67,295	42,775	11,897	3,524	43,988	65,528
United States										
Eagle Ford	-	42,109	13,524	84,950	69,792	-	48,971	15,491	90,528	79,551
Total	42,628	54,140	18,012	133,845	137,087	42,775	60,868	19,015	134,516	145,079

This press release contains metrics commonly used in the oil and natural gas industry, such as "finding and development costs", "recycle ratio", "production replacement", and "reserves life index". These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included in this press release to provide readers with additional measures to evaluate Baytex's performance, however, such measures are not reliable indicators of Baytex's future performance and future performance may not compare to Baytex's performance in previous periods and therefore such metrics should not be unduly relied upon.

Finding and development costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserves category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category.

Recycle ratio is calculated by dividing operating netback on a per boe basis by finding and development costs for the particular reserves category.

Production replacement is calculated by dividing reserves additions, including extensions, technical revisions and economic factors for the particular reserves category, by annual production.

Reserves life index is calculated by taking the total quantity of reserves on a boe basis divided by annualized Q4/2025 production (boe/d) in Canada.

Notice to United States Readers

The petroleum and natural gas reserves contained in this press release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves". Additionally, NI 51-101 defines "proved reserves" and "probable reserves" differently from the SEC rules. Accordingly, proved and probable *reserves disclosed in this press release may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves.*

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, Baytex has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, Baytex's reserve estimates and production volumes in this press release may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

Baytex Energy Corp.

Baytex Energy Corp. is a Calgary-based energy company committed to driving shareholder value through disciplined execution. It operates a high-quality, high-return portfolio in the Western Canadian Sedimentary Basin, featuring the Pembina Duvernay and heavy oil plays in Alberta and Saskatchewan. These core assets are backed by an extensive drilling inventory and consistently generate strong cash flow. 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 and Investor Relations

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

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