BAYTEX ANNOUNCES FOURTH QUARTER AND FULL YEAR 2024 FINANCIAL AND OPERATING RESULTS AND YEAR END RESERVES

CALGARY, ALBERTA (March 4, 2025) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2024 (all amounts are in Canadian dollars unless otherwise noted).

"Our strong 2024 results speak to our disciplined, returns-based capital allocation philosophy that delivers increased per-share returns. In 2024, we generated 10% production per share growth and grew reserves per-share across all reserves categories. We executed our capital program on budget, generated meaningful free cash flow and returned $290 million to shareholders through our buyback program and quarterly dividend. For 2025, we will continue to prioritize free cash flow and shareholder returns," commented Eric T. Greager, President and Chief Executive Officer.

2024 Highlights

- Reported cash flows from operating activities of $469 million ($0.60 per basic share) in Q4/2024 and $1,908 million ($2.38 per basic share) for 2024.
- Increased production per basic share by 10% in 2024, compared to 2023. Production for the full-year 2024 averaged 153,048 boe/d (85% oil and NGL), compared to 122,154 boe/d in 2023 (85% oil and NGL). Production in Q4/2024 averaged 152,894 boe/d (84% oil and NGL).
- Delivered adjusted funds flow(1) of $462 million ($0.59 per basic share) in Q4/2024 and $1,957 million ($2.44 per basic share) for 2024.
- Generated free cash flow(2) of $255 million ($0.33 per basic share) in Q4/2024 and $656 million ($0.82 per basic share) for 2024.
- Returned $290 million to shareholders in 2024 through our share buyback program and dividend. We repurchased 48.4 million common shares for $218 million, representing 6% of our shares outstanding. In addition, we declared four quarterly dividends of $0.0225 per share, totaling $72 million.
- Improved our cash cost structure (operating, transportation, and general & administrative expenses) in 2024 by 5% on a boe basis, as compared to 2023.
- Reduced net debt(1) by 5% in 2024 (13% in U.S. dollars) and maintained balance sheet strength with a total debt to EBITDA ratio(3) of 1.1x.

Reserves Highlights (4)

- Achieved strong per-share growth and reserves replacement across all three reserves categories, proved developed producing ("PDP"), proved ("1P") and proved plus probable ("2P").
- Increased PDP reserves per share by 8% and 1P and 2P reserves per share by 6%. PDP reserves total 187 MMboe, 1P reserves total 408 MMboe and 2P reserves total 660 MMboe.
- Replaced 102% of production on a 1P basis and 101% of production on a 2P basis, excluding acquisition and divestiture activity.
- Generated a strong PDP recycle ratio of 1.9x and a 1P and 2P recycle ratio of 2.7x based on a 2024 operating netback(2) of $40.67/boe, reflective of the efficiency of our capital program and high netback oil-weighted portfolio.
- Increased our net asset value at year-end 2024, discounted at 10% before tax, 13% to $7.27 per share ($6.41 per share at year-end 2023). This is based on the estimated 2P reserves value, net of long-term debt and working capital.

(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) Ratio is calculated as total debt at December 31, 2024 divided by EBITDA for the twelve months ended December 31, 2024. Total debt and EBITDA are calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.
(4) Baytex's year-end 2024 reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101").

	Three Months Ended			Twelve Months Ended	
	December 31, 2024	September 30, 2024	December 31, 2023	**December 31, 2024**	December 31, 2023
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 1,017,017**	$ 1,074,623	$ 1,065,515	**$ 4,208,955**	$ 3,382,621
Adjusted funds flow (1)	**461,886**	537,947	502,148	**1,956,518**	1,594,350
Per share – basic	**0.59**	0.68	0.60	**2.44**	2.26
Per share – diluted	**0.59**	0.67	0.60	**2.42**	2.26
Free cash flow (2)	**254,838**	220,159	290,785	**655,582**	543,620
Per share – basic	**0.33**	0.28	0.35	**0.82**	0.77
Per share – diluted	**0.33**	0.28	0.35	**0.81**	0.77
Cash flows from operating activities	**468,865**	550,042	474,452	**1,908,264**	1,295,731
Per share – basic	**0.60**	0.69	0.57	**2.38**	1.84
Per share – diluted	**0.60**	0.69	0.57	**2.36**	1.84
Net income (loss)	**(38,477)**	185,219	(625,830)	**236,597**	(233,356)
Per share – basic	**(0.05)**	0.23	(0.75)	**0.29**	(0.33)
Per share – diluted	**(0.05)**	0.23	(0.75)	**0.29**	(0.33)
Dividends declared	**17,598**	17,732	18,381	**71,985**	37,519
Per share	**0.0225**	0.0225	0.0225	**0.090**	0.045
Capital Expenditures					
Exploration and development expenditures	**$ 198,177**	$ 306,332	$ 199,214	**$ 1,256,633**	$ 1,012,787
Acquisitions and (divestitures)	**(29,718)**	(394)	(125,822)	**5,920**	(121,342)
Total oil and natural gas capital expenditures	**$ 168,459**	$ 305,938	$ 73,392	**$ 1,262,553**	$ 891,445
Net Debt					
Credit facilities	**$ 341,207**	$ 466,108	$ 864,736	**$ 341,207**	$ 864,736
Long-term notes	**1,980,619**	1,856,869	1,597,475	**1,980,619**	1,597,475
Total debt (3)	**2,321,826**	2,322,977	2,462,211	**2,321,826**	2,462,211
Working capital deficiency (2)	**95,346**	170,292	72,076	**95,346**	72,076
Net debt (1)	**$ 2,417,172**	$ 2,493,269	$ 2,534,287	**$ 2,417,172**	$ 2,534,287
Shares Outstanding - basic (thousands)					
Weighted average	**782,131**	796,064	831,063	**803,435**	704,896
End of period	**773,590**	787,328	821,681	**773,590**	821,681
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 70.27**	$ 75.10	$ 78.32	**$ 75.72**	$ 77.62
MEH oil (US$/bbl)	**72.40**	77.50	80.62	**77.99**	79.29
MEH oil differential to WTI (US$/bbl)	**2.13**	2.40	2.30	**2.27**	1.67
Edmonton par ($/bbl)	**94.98**	97.91	99.72	**97.59**	100.46
Edmonton par differential to WTI (US$/bbl)	**(2.39)**	(3.30)	(5.10)	**(4.49)**	(3.18)
WCS heavy oil ($/bbl)	**80.77**	83.98	76.86	**83.56**	79.58
WCS differential to WTI (US$/bbl)	**(12.54)**	(13.51)	(21.88)	**(14.73)**	(18.65)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.79**	$ 2.16	$ 2.88	**$ 2.27**	$ 2.74
AECO ($/mcf)	**1.46**	0.81	2.66	**1.44**	2.93
CAD/USD average exchange rate	**1.3992**	1.3636	1.3619	**1.3700**	1.3495

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			Twelve Months Ended	
	December 31, 2024	September 30, 2024	December 31, 2023	**December 31, 2024**	December 31, 2023
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**64,661**	69,843	70,124	**66,894**	53,389
Heavy oil (bbl/d)	**42,227**	42,759	39,569	**42,313**	35,460
NGL (bbl/d)	**21,208**	19,836	23,160	**20,129**	14,304
Total liquids (bbl/d)	**128,096**	132,438	132,853	**129,336**	103,153
Natural gas (mcf/d)	**148,792**	132,175	165,121	**142,262**	114,010
Oil equivalent (boe/d @ 6:1) (1)	**152,894**	154,468	160,373	**153,048**	122,154
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 936,869**	$ 1,022,721	$ 1,003,219	**$ 3,945,012**	$ 3,157,819
Royalties	**(206,675)**	(223,800)	(228,570)	**(880,086)**	(669,792)
Operating expense	**(145,690)**	(167,119)	(164,873)	**(653,949)**	(570,839)
Transportation expense	**(33,110)**	(36,883)	(29,744)	**(133,142)**	(89,306)
Operating netback (2)	**$ 551,394**	$ 594,919	$ 580,032	**$ 2,277,835**	$ 1,827,882
General and administrative	**(20,433)**	(17,895)	(22,280)	**(81,746)**	(69,789)
Cash interest	**(48,769)**	(50,109)	(56,698)	**(206,104)**	(159,823)
Realized financial derivatives (loss) gain	**(2,115)**	331	12,377	**1,447**	36,212
Other (3)	**(18,191)**	10,701	(11,283)	**(34,914)**	(40,132)
Adjusted funds flow (4)	**$ 461,886**	$ 537,947	$ 502,148	**$ 1,956,518**	$ 1,594,350
Netback per boe (2)					
Total sales, net of blending and other expense (2)	**$ 66.60**	$ 71.97	$ 68.00	**$ 70.43**	$ 70.82
Royalties (5)	**(14.69)**	(15.75)	(15.49)	**(15.71)**	(15.02)
Operating expense (5)	**(10.36)**	(11.76)	(11.17)	**(11.67)**	(12.80)
Transportation expense (5)	**(2.35)**	(2.60)	(2.02)	**(2.38)**	(2.00)
Operating netback (2)	**$ 39.20**	$ 41.86	$ 39.32	**$ 40.67**	$ 41.00
General and administrative (5)	**(1.45)**	(1.26)	(1.51)	**(1.46)**	(1.57)
Cash interest (5)	**(3.47)**	(3.53)	(3.84)	**(3.68)**	(3.58)
Realized financial derivatives (loss) gain (5)	**(0.15)**	0.02	0.84	**0.03**	0.81
Other (3)	**(1.29)**	0.76	(0.78)	**(0.63)**	(0.90)
Adjusted funds flow (4)	**$ 32.84**	$ 37.85	$ 34.03	**$ 34.93**	$ 35.76

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 share-based compensation. Refer to the 2024 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 expense or realized financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

2025 Outlook

Baytex is a well-capitalized, North American oil-weighted producer with 60% of our production in the Eagle Ford in Texas and the balance in western Canada.

In 2025, the government of the United States of America announced tariffs on goods imported from Canada, including a 10% tariff on Canadian energy imports, effective March 4, 2025. We continue to monitor the impact of these tariffs and expect that our geographic diversification will provide a measure of insulation.

We are focused on disciplined capital allocation to prioritize free cash flow generation while maintaining a strong balance sheet. In the current commodity price environment this means moderating our growth profile and delivering stable crude oil production. We currently allocate approximately 50% of free cash flow(1) to the balance sheet and approximately 50% to shareholder returns, which includes a combination of share buybacks and quarterly dividend payments.

In 2025, we are targeting continued strong performance in the Eagle Ford, further progression of the Pembina Duvernay and capital efficient heavy oil development. We anticipate first quarter production of approximately 144,000 boe/d with volumes increasing over the balance of the year. During the first quarter, extremely cold temperatures across North America resulted in modest production disruptions across our operations. Our full year 2025 guidance is unchanged with exploration and development expenditures of $1.2 to $1.3 billion and production of 148,000 to 152,000 boe/d.

We expect to generate approximately $400 million of free cash flow in 2025 at US$70/bbl WTI. Based on our production profile and timing of capital expenditures, the majority of our free cash flow is expected to be generated in the second half of the year.

2024 Results

We delivered operating and financial results consistent with our full-year plan. Production and exploration and development expenditures were in line with full-year guidance and we improved our cash cost structure (operating, transportation, general & administrative expenses) by 5% on a boe basis, compared to 2023. Adjusted funds flow(2) totaled $2.0 billion ($2.44 per basic share) and we generated net income of $237 million ($0.29 per basic share).

We increased production per basic share by 10% in 2024, compared to 2023, with production averaging 153,048 boe/d (84% oil and NGL), up from 122,154 boe/d in 2023. Production in Q4/2024 averaged 152,894 boe/d (84% oil and NGL). Exploration and development expenditures totaled $1.26 billion in 2024 and we participated in the drilling of 290 (246.4 net) wells.

We generated free cash flow of $656 million ($0.82 per basic share) in 2024 and returned $290 million to shareholders through our share buyback program and dividend. We repurchased 48.4 million common shares for $218 million, representing 6% of our shares outstanding, at an average price of $4.50 per share. In addition, we declared four quarterly dividends of $0.0225 per share, totaling $72 million.

Over the last six quarters, we generated free cash flow of $1.1 billion and returned $550 million to shareholders through our share buyback program and dividend. We repurchased 88.9 million common shares for $440 million, representing 10% of our shares outstanding, at an average price of $4.95 per share. In addition, we declared six quarterly dividends of $0.0225 per share, totaling $110 million.

On December 20, 2024, we completed the divestiture of our Kerrobert thermal asset in southwest Saskatchewan for net proceeds of $41.5 million. Proceeds from the sale were applied against our credit facilities. Production from the assets at the time of the sale was approximately 2,000 bbl/d (100% heavy oil).

We reduced net debt(2) by 5% ($117 million) in 2024. Our strong free cash flow generation was significantly offset by the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt. In U.S. dollars, we reduced net debt by 13% (US$241 million). On an annual basis, a $0.05 CAD/USD change in the foreign exchange rate impacts our net debt by approximately $70 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 press release for further information.
(2) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.

Operations

In the Eagle Ford, production averaged 89,100 boe/d (81% oil and NGL) in 2024 and we brought onstream 64 net wells, including 51 net operated wells. Our development program was largely focused on the black oil and volatile oil 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 realized an 8% improvement in operated drilling and completion costs per completed lateral foot over 2023.

In the Eagle Ford, we expect to bring onstream 54 net wells in 2025, including 41 net operated wells. We intend to run a consistent two rig and one frac crew program for most of the year 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 unit, production averaged 16,701 boe/d (83% oil and NGL) in 2024. We made substantial strides in advancing our understanding of the Pembina Duvernay with production increasing 64% to 6,112 boe/d (82% oil and NGL) in 2024, compared to 2023. We brought onstream seven net wells in the Pembina Duvernay and 95 net wells in the the Viking. In 2025, we expect to bring onstream nine net wells in the Pembina Duvernay and 90 net wells in the Viking.

In our heavy oil business unit, production averaged 43,704 boe/d (95% oil and NGL) in 2024. Peavine continued to deliver top well results with production increasing 44% to 19,241 bbl/d (100% heavy oil) in 2024, compared to 2023. During 2024, we brought onstream 31 net Clearwater wells at Peavine, 9 net wells at Peace River and 40 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.

Subsequent to year-end, we acquired through an asset exchange, 44.5 net sections of land on the Peavine Métis settlement. The lands acquired are immediately adjacent to our existing 90-section acreage position.

Quarterly Dividend

The Board of Directors has declared a quarterly cash dividend of $0.0225 per share to be paid on April 1, 2025 for shareholders of record on March 14, 2025.

Year-end 2024 Reserves

Baytex's year-end 2024 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 Associates Limited (“Sproule”) as of January 1, 2025.

For additional information regarding Baytex's reserves as at December 31, 2024, see Baytex's Annual Information Form for the year ended December 31, 2024 on Baytex's SEDAR+ profile at www.sedarplus.ca, and Baytex's U.S. Form 40-F for the year ended December 31, 2024 on EDGAR at www.sec.gov, each of which are anticipated to be filed on March 4, 2025.

Reserves Summary

- We achieved strong reserves replacement and per-share growth across all three reserves categories, proved developed producing ("PDP") , proved ("1P") and proved plus probable ("2P").
- We invested $1.26 billion on exploration and development expenditures in 2024 and replaced 102% of production on a 1P basis and 101% of production on a 2P basis, excluding acquisition and divestiture activity. In 2024, we divested our Kerrobert thermal asset which reduced 1P and 2P reserves by 2.9 MMboe and 4.2 MMboe, respectively.
- PDP reserves per share increased 8% and 1P and 2P reserves per share increased 6%. PDP reserves total 187 MMboe (185 MMboe at year-end 2023), 1P reserves total 408 MMboe (410 MMboe at year-end 2023) and 2P reserves total 660 MMboe (663 MMboe at year-end 2023).
- We generated a strong PDP recycle ratio of 1.9x and a 1P and 2P recycle ratio of 2.7x based on a 2024 operating netback(1) of $40.67/boe, reflective of the efficiency of our capital program and high netback oil-weighted portfolio.
- Finding and development ("F&D") costs, including changes in future development costs (“FDC”), were $21.32/boe for PDP reserves, $15.06/boe for 1P reserves and $14.81/boe for 2P reserves.
- At year-end 2024, the present value of our reserves, discounted at 10% before tax, is estimated to be $5.0 billion ($5.0 billion at year-end 2023) on a 1P basis and $8.0 billion ($7.8 billion at year-end 2023) on a 2P basis.
- Our net asset value at year-end 2024, discounted at 10% before tax, increased 13% to $7.27 per share ($6.41 per share at year-end 2023). This is based on the estimated 2P reserves value, net of long-term debt and working capital.
- Our booked drilling locations within 2P reserves represents approximately 52% of our 2,911 net risked drilling locations in inventory.
- FDC on a 1P basis decreased to $5.6 billion ($6.0 billion at year-end 2023) and on a 2P basis, decreased to $8.6 billion ($9.1 billion at year-end 2023), largely attributable to reduced drilling and completion costs in the Eagle Ford.
- Reserves on a 1P basis are comprised of 83% oil and NGLs (47% light oil, 22% NGLs and 14% heavy oil) and 17% natural gas.
- Baytex maintains a strong reserves life index of 7.5 years based on 1P reserves and 12.1 years based on 2P reserves (using the mid-point of 2025 production guidance).

(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 press release for further information.

The following table sets forth our gross and net reserves volumes at December 31, 2024 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	9,131	73,924	34,250	—	117,305	37,317	48,570	146,964	187,211
Proved developed non-producing	352	1,517	2,024	—	3,893	1,489	1,596	4,302	6,364
Proved undeveloped	14,122	92,759	19,082	—	125,963	53,117	24,623	188,509	214,602
Total proved	23,604	168,200	55,357	—	247,161	91,923	74,789	339,775	408,177
Total probable	13,644	84,798	34,190	44,489	177,121	42,813	38,344	152,995	251,824
Proved plus probable	37,248	252,998	89,547	44,489	424,281	134,736	113,133	492,770	660,001
Net [2]									
Proved producing	8,662	56,721	28,915	—	94,298	28,620	44,240	113,214	149,160
Proved developed non-producing	329	1,121	1,808	—	3,257	1,108	1,494	3,188	5,145
Proved undeveloped	13,362	72,117	16,720	—	102,200	41,121	21,496	147,217	171,440
Total proved	22,353	129,958	47,443	—	199,754	70,849	67,231	263,618	325,745
Total probable	12,670	65,263	28,224	34,897	141,054	33,290	33,877	120,376	200,052
Proved plus probable	35,023	195,221	75,667	34,897	340,808	104,139	101,107	383,994	525,797

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

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, 2023	25,803	162,782	51,078	3,783	243,447	94,840	77,910	353,924	410,259
Extensions	1,496	18,691	12,064	—	32,251	9,809	4,256	40,792	49,568
Technical Revisions	(498)	7,592	6,163	—	13,257	(4,574)	6,227	(14,867)	7,243
Acquisitions	—	—	383	—	383	—	—	—	383
Dispositions	—	(207)	(109)	(2,941)	(3,257)	(68)	(8)	(345)	(3,384)
Economic Factors	70	(54)	422	—	438	(105)	(892)	(366)	123
Production	(3,266)	(20,605)	(14,645)	(842)	(39,358)	(7,979)	(12,704)	(39,363)	(56,015)
December 31, 2024	23,604	168,200	55,357	—	247,161	91,923	74,789	339,775	408,177

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, 2023	14,997	85,238	32,935	45,754	178,923	42,334	38,246	151,764	252,925
Extensions	276	1,689	2,509	—	4,474	1,603	2,270	7,419	7,692
Technical Revisions	(1,646)	(1,964)	(1,759)	(27)	(5,396)	(1,050)	(1,625)	(5,884)	(7,699)
Acquisitions	—	—	518	—	518	—	—	—	518
Dispositions	—	(146)	(36)	(1,238)	(1,420)	(48)	(2)	(225)	(1,507)
Economic Factors	17	(18)	23	—	22	(24)	(545)	(79)	(106)
Production	—	—	—	—	—	—	—	—	—
December 31, 2024	13,644	84,798	34,190	44,489	177,121	42,813	38,344	152,995	251,824

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, 2023	40,799	248,020	84,013	49,537	422,370	137,173	116,156	505,688	663,184
Extensions	1,772	20,380	14,573	—	36,725	11,412	6,526	48,212	57,260
Technical Revisions	(2,144)	5,627	4,404	(27)	7,860	(5,624)	4,601	(20,752)	(456)
Acquisitions	—	—	901	—	901	—	—	—	901
Dispositions	—	(353)	(145)	(4,179)	(4,677)	(116)	(10)	(570)	(4,890)
Economic Factors	87	(72)	445	—	460	(130)	(1,436)	(445)	17
Production	(3,266)	(20,605)	(14,645)	(842)	(39,358)	(7,979)	(12,704)	(39,363)	(56,015)
December 31, 2024	37,248	252,997	89,547	44,489	424,281	134,736	113,133	492,770	660,001

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.

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
2025	1,079	1,155
2026	1,081	1,214
2027	1,296	1,478
2028	1,317	1,512
2029	731	1,354
Remainder	53	1,896
Total FDC undiscounted	5,556	8,608

F&D and FD&A Costs – including future development costs

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

$ millions except for per boe amounts	2024	2023	2022	3 Year
Proved plus Probable Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 1,256.6	$ 1,012.8	$ 521.5	$ 2,791.0
Net change in Future Development Costs	$ (415.5)	$ 841.2	$ 588.6	$ 1,014.4
Gross Reserves additions (MMboe)	56.8	64.6	26.2	147.6
F&D Costs ($/boe)	$ 14.81	$ 28.68	$ 42.34	$ 25.77
Finding, Development & Acquisition ("FD&A") Costs				
Exploration and development expenditures and net acquisitions	$ 1,262.6	$ 3,948.5	$ 497.2	$ 5,708.3
Net change in Future Development Costs	$ (443.0)	$ 4,763.6	$ 537.6	$ 4,858.1
Gross Reserves additions (MMboe)	52.8	270.2	17.2	340.2
FD&A Costs ($/boe)	$ 15.51	$ 32.25	$ 60.05	$ 31.06
Proved Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 1,256.6	$ 1,012.8	$ 521.5	$ 2,791.0
Net change in Future Development Costs	$ (399.4)	$ 491.7	$ 320.1	$ 412.4
Gross Reserves additions (MMboe)	56.9	50.5	21.4	128.7
F&D Costs ($/boe)	$ 15.06	$ 29.82	$ 39.40	$ 24.89
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$ 1,262.6	$ 3,948.5	$ 497.2	$ 5,708.3
Net change in Future Development Costs	$ (430.0)	$ 3,290.6	$ 285.0	$ 3,145.6
Gross Reserves additions (MMboe)	53.9	190.6	16.6	261.0
FD&A Costs ($/boe)	$ 15.46	$ 37.98	$ 47.25	$ 33.92
Proved Developed Producing Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 1,256.6	$ 1,012.8	$ 521.5	$ 2,791.0
Gross Reserves additions (MMboe)	58.9	41.8	27.2	127.9
F&D Costs ($/boe)	$ 21.32	$ 24.23	$ 19.20	$ 21.82
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$ 1,262.6	$ 3,948.5	$ 497.2	$ 5,708.3
Gross Reserves additions (MMboe)	57.9	104.8	26.0	188.6
FD&A Costs ($/boe)	$ 21.81	$ 37.69	$ 19.13	$ 30.26

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, 2024. 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, 2025.

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
2024 act.	76.55	97.50	83.60	2.20	1.45	2.4	0.730
2025	71.58	94.79	82.69	3.31	2.36	—	0.712
2026	74.48	97.04	84.27	3.73	3.33	2.0	0.728
2027	75.81	97.37	83.81	3.85	3.48	2.0	0.743
2028	77.66	99.80	85.70	3.93	3.69	2.0	0.743
2029	79.22	101.79	87.45	4.01	3.76	2.0	0.743
2030	80.80	103.83	89.25	4.09	3.83	2.0	0.743
2031	82.42	105.91	91.04	4.17	3.91	2.0	0.743
2032	84.06	108.03	92.85	4.26	3.99	2.0	0.743
2033	85.74	110.19	94.71	4.34	4.07	2.0	0.743
2034	87.46	112.39	96.61	4.43	4.15	2.0	0.743
Thereafter	Escalation rate of 2.0%					2.0	0.743

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, 2024 ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	3,665	3,751	3,389	3,054
Proved developed non-producing	235	171	138	117
Proved undeveloped	3,702	2,338	1,519	989
Total proved	7,602	6,260	5,046	4,159
Probable	8,242	4,672	2,997	2,093
Total Proved Plus Probable (before tax)	15,844	10,932	8,043	6,252

Note:

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

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2024 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.

Conference Call Tomorrow
9:00 a.m. MST (11:00 a.m. EST)

Baytex will host a conference call tomorrow, March 5, 2025, starting at 9:00am MST (11:00am EST). To participate, please dial toll free in North America 1-844-763-8274 or international 1-647-484-8814. Alternatively, to listen to the conference call online, please enter https://event.choruscall.com/mediaframe/webcast.html?webcastid=zgaTXTCO in your web browser.

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: for 2025, that we will prioritize free cash flow and shareholder returns; that we expect to be insulated from tariffs as a result of our geographic diversification; our intention to allocate free cash flow to each of debt repayment and shareholder returns (including share buybacks and quarterly dividends) and the expected allocation of such free cash flow; our development plans for 2025, our expected Q1/2025 and full-year production volumes and full year exploration and development expenditures; our anticipated free cash flow for 2024 and that the majority is expected to be generated in H2/2025; the anticipated impact of the CAD/US exchange rate on our net debt; our 2025 drilling plans, including the number of net wells we intend to bring online and our targeted 7% improvement in operated drilling and completion costs in the operated Eagle Ford; 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 (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 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, 2024, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission on March 4, 2024 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 2025 guidance for development expenditures; our expected 2025 free cash flow; and our intentions of allocating our annual free cash flow to shareholder returns through a share buyback and debt reduction; 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 certain financial measures (such as free cash flow, operating netback, working capital deficiency and total sales, net of blending and other expense) 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 is used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense.

The following table reconciles operating netback to petroleum and natural gas sales.

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023	**2024**	2023
Petroleum and natural gas sales	**$ 1,017,017**	$ 1,074,623	$ 1,065,515	**$ 4,208,955**	$ 3,382,621
Blending and other expense	**(80,148)**	(51,902)	(62,296)	**(263,943)**	(224,802)
Total sales, net of blending and other expense	**$ 936,869**	$ 1,022,721	$ 1,003,219	**$ 3,945,012**	$ 3,157,819
Royalties	**(206,675)**	(223,800)	(228,570)	**(880,086)**	(669,792)
Operating expense	**(145,690)**	(167,119)	(164,873)	**(653,949)**	(570,839)
Transportation expense	**(33,110)**	(36,883)	(29,744)	**(133,142)**	(89,306)
Operating netback	**$ 551,394**	$ 594,919	$ 580,032	**$ 2,277,835**	$ 1,827,882

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, transaction costs, additions to exploration and evaluation assets, additions to oil and gas properties, payments on lease obligations, and cash premiums on derivatives.

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

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023	**2024**	2023
Cash flows from operating activities	**$ 468,865**	$ 550,042	$ 474,452	**$ 1,908,264**	$ 1,295,731
Change in non-cash working capital	**(13,428)**	(20,813)	14,971	**17,922**	220,895
Transaction costs	**—**	—	5,079	**1,539**	49,045
Additions to exploration and evaluation assets	**—**	—	1,271	**—**	—
Additions to oil and gas properties	**(198,177)**	(306,332)	(200,537)	**(1,256,633)**	(1,012,787)
Payments on lease obligations	**(2,422)**	(2,738)	(4,451)	**(15,510)**	(11,527)
Cash premiums on derivatives	**—**	—	—	**—**	2,263
Free cash flow	**$ 254,838**	$ 220,159	$ 290,785	**$ 655,582**	$ 543,620

Working capital deficiency

Working capital deficiency is calculated as cash, trade receivables, and 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 December 31, 2024, the Company had $1.2 billion of available credit facility capacity to cover any working capital deficiencies.

The following table summarizes the calculation of working capital deficiency.

	As at		
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023
Cash	**$ (16,610)**	$ (21,311)	$ (55,815)
Trade receivables	**(387,266)**	(375,942)	(339,405)
Prepaids and other assets	**(76,468)**	(78,427)	(83,259)
Trade payables	**512,473**	584,696	477,295
Share-based compensation liability	**24,732**	23,962	35,732
Other long-term liabilities	**20,887**	19,582	19,147
Dividends payable	**17,598**	17,732	18,381
Working capital deficiency	**$ 95,346**	$ 170,292	$ 72,076

Non-GAAP Financial Ratios

Total sales, net of blending and other expense per boe

Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period.

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)	**December 31, 2024**	September 30, 2024	December 31, 2023
Credit facilities	**$ 324,346**	$ 449,116	$ 848,749
Unamortized debt issuance costs - Credit facilities (1)	**16,861**	16,992	15,987
Long-term notes	**1,932,890**	1,810,701	1,562,361
Unamortized debt issuance costs - Long-term notes (1)	**47,729**	46,168	35,114
Trade payables	**512,473**	584,696	477,295
Share-based compensation liability	**24,732**	23,962	35,732
Dividends payable	**17,598**	17,732	18,381
Other long-term liabilities	**20,887**	19,582	19,147
Cash	**(16,610)**	(21,311)	(55,815)
Trade receivables	**(387,266)**	(375,942)	(339,405)
Prepaids and other assets	**(76,468)**	(78,427)	(83,259)
Net debt	**$ 2,417,172**	$ 2,493,269	$ 2,534,287

(1) Unamortized debt issuance costs were obtained from Note 8 Credit Facilities and Note 9 Long-term Notes from the Consolidated Financial Statements for the year ended December 31, 2024.

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, transaction costs, and cash premiums on derivatives during the applicable period.

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

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023	**2024**	2023
Cash flows from operating activities	**$ 468,865**	$ 550,042	$ 474,452	**$ 1,908,264**	$ 1,295,731
Change in non-cash working capital	**(13,428)**	(20,813)	14,971	**17,922**	220,895
Asset retirement obligations settled	**6,449**	8,718	7,646	**28,793**	26,416
Transaction costs	**—**	—	5,079	**1,539**	49,045
Cash premiums on derivatives	**—**	—	—	**—**	2,263
Adjusted funds flow	**$ 461,886**	$ 537,947	$ 502,148	**$ 1,956,518**	$ 1,594,350

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, 2024, which will be filed on March 4, 2025. 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 Eagle Ford, Baytex's net drilling locations include 331 proved and 140 probable locations as at December 31, 2024 and 294 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 663 unbooked locations. In the Viking, Baytex's net drilling locations include 541 proved and 168 probable locations as at December 31, 2024 and 261 unbooked locations. In the Duvernay, Baytex's net drilling locations include 42 proved and 20 probable locations as at December 31, 2024 and 180 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, 2024. 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, 2024					Twelve Months Ended December 31, 2024				
	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	9,380	9	26	9,976	11,078	9,250	10	37	10,691	11,080
Lloydminster	12,848	15	—	1,267	13,074	13,119	16	—	1,491	13,383
Peavine	19,333	—	—	—	19,333	19,241	—	—	—	19,241
Canada - Light										
Viking	24	7,916	194	9,486	9,715	6	8,717	187	10,075	10,589
Duvernay	—	3,418	2,536	7,918	7,273	—	2,941	2,054	6,700	6,112
Remaining Properties	642	210	763	19,466	4,859	697	300	471	12,455	3,544
United States										
Eagle Ford	—	53,093	17,689	100,679	87,562	—	54,911	17,380	100,850	89,100
Total	42,227	64,661	21,208	148,792	152,894	42,313	66,894	20,129	142,262	153,048

This press release contains metrics commonly used in the oil and natural gas industry, such as "finding and development costs", "finding, development and acquisition costs", "PDP recycle ratio", "1P recycle ratio", and "2P recycle ratio". 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.

Finding, development and acquisition 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 development and exploration activities and property acquisitions (net of dispositions) in the year by the change in reserves from the 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.

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 an energy company based in Calgary, Alberta. 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. Approximately 85% of Baytex's production is weighted toward crude oil and natural gas liquids. 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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BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the years ended December 31, 2024 and 2023
Dated March 4, 2025

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the years ended December 31, 2024 and 2023. This information is provided as of March 4, 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 and year ended December 31, 2024 ("Q4/2024" and "2024") have been compared with the results for the three months and year ended December 31, 2023 ("Q4/2023" and "2023"). This MD&A should be read in conjunction with the Company's audited consolidated financial statements ("consolidated financial statements") for the years ended December 31, 2024 and 2023, together with the accompanying notes and the 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 issued by the International Accounting Standards Board ("IASB"). The terms "operating netback", "free cash flow", "average royalty rate", "heavy oil, net of blending and other expense" and "total sales, net of blending and other expense" are specified financial measures that do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. This MD&A also contains the terms "adjusted funds flow" and "net 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 energy 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.

On June 20, 2023, Baytex and Ranger Oil Corporation ("Ranger") completed the merger of the two companies (the "Merger") whereby Baytex acquired all of the issued and outstanding common shares of Ranger. The Merger increased our Eagle Ford scale and provides an operating platform to effectively allocate capital across the Western Canadian Sedimentary Basin and the Eagle Ford. Production from the Ranger assets is approximately 80% weighted towards high netback light oil and liquids and is primarily operated which increases our ability to effectively allocate capital.

We issued 311.4 million common shares, paid $732.8 million in cash and assumed $1.1 billion of Ranger's net debt[(1)]. The cash portion of the transaction was funded with an expanded US$1.1 billion credit facility, a US$150 million two-year term loan facility and the net proceeds from the issuance of US$800 million senior unsecured notes due 2030.

2024 ANNUAL HIGHLIGHTS

Baytex delivered strong operating and financial results in 2024. Annual production of 153,048 boe/d was consistent with our revised annual guidance of approximately 153,000 boe/d and reflects strong results from our drilling programs in Western Canada and the Eagle Ford in Texas. We invested $1.26 billion in exploration and development expenditures and generated free cash flow[(2)] of $655.6 million in 2024.

Exploration and development expenditures totaled $1.26 billion for 2024. In the U.S. we invested $767.1 million during 2024 and production averaged 89,100 boe/d which is higher than 60,997 boe/d in 2023 with the Merger occurring halfway through the year. In Canada, we invested $489.5 million in 2024 and generated production of 63,948 boe/d during 2024 compared to 61,157 boe/d in 2023 which reflects growth driven by strong well performance from our heavy oil development which more than offset the effect of a non-core Viking light oil disposition in Q4/2023.

(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.

Oil prices were relatively stable in 2024 as a result of global supply growth, weaker demand and global economic concerns. The average WTI benchmark price for 2024 was US$75.72/bbl which was US$1.90/bbl lower than 2023 when WTI averaged US$77.62/bbl. Our financial results for 2024 reflect higher production partially offset by lower realized pricing which resulted in adjusted funds flow[(1)] of $2.0 billion and cash flows from operating activities of $1.9 billion for 2024 compared to 2023 when we generated adjusted funds flow of $1.6 billion and cash flows from operating activities of $1.3 billion.

Net debt[(1)] of $2.4 billion at December 31, 2024 was 5% lower than $2.5 billion at December 31, 2023 which reflects our allocation of free cash flow to debt repayment in 2024. Free cash flow of $655.6 million generated in 2024 was allocated to debt repayment along with $289.9 million of shareholder returns including share buybacks and quarterly dividends. The change in net debt also reflects $49.7 million of debt issuance costs incurred during 2024 along with a $176.9 million foreign exchange loss on our U.S. dollar denominated net debt due to a weaker Canadian dollar at December 31, 2024. At December 31, 2024, our net debt on a U.S. dollar denominated based was reduced by US$241 million or 13% relative to December 31, 2023.

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

GUIDANCE

Our 2025 annual guidance includes exploration and development expenditures of $1.2 - $1.3 billion and is designed to generate annual production of 148,000 - 152,000 boe/d.

The following table compares our 2024 revised annual guidance and 2025 annual guidance to our 2024 results. Production, exploration and development expenditures, and expenses for 2024 were consistent with our revised annual guidance for 2024, which reflects our ongoing efforts to deliver strong operating results while we maintain a competitive cost structure.

	2024 Revised Annual Guidance (1)	2024 Results	2025 Annual Guidance (2)
Exploration and development expenditures	~ $1.25 billion	$1.26 billion	$1.2 - $1.3 billion
Production (boe/d)	~ 153,000	153,048	148,000 - 152,000 (6)
Expenses:			
Average royalty rate (3)	~ 22.5%	22.3%	~ 23%
Operating (4)	~ $12.00/boe	$11.67/boe	$11.75 - $12.50/boe
Transportation (4)	~ $2.45/boe	$2.38/boe	$2.40 - $2.55/boe
General and administrative (4)	$85 million ($1.52/boe)	$81.7 million ($1.46/boe)	$90 million ($1.64/boe) (6)
Cash Interest (4)	$200 million ($3.58/boe)	$206.1 million ($3.68/boe)	$180 million ($3.29/boe) (6)
Current Income Taxes (5)	$25 million ($0.45/boe)	$21.7 million ($0.39/boe)	~ 1% of EBITDA (3)
Leasing expenditures	$15 million	$16 million	$10 million
Asset retirement obligations settled	$30 million	$29 million	$25 million

(1) As announced on October 31, 2024.
(2) As announced on December 3, 2024.
(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 description of the composition of these measures.
(5) 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.
(6) As announced December 20, 2024 in conjunction with the Kerrobert Thermal asset sale. Per boe amounts for General and administrative and cash interest costs have been updated for the change in guidance for production.

RESULTS OF OPERATIONS

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.

Production

	Years Ended December 31					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**11,983**	**54,911**	**66,894**	15,698	37,691	53,389
Heavy oil	**42,313**	**—**	**42,313**	35,460	—	35,460
Natural Gas Liquids ("NGL")	**2,749**	**17,380**	**20,129**	2,090	12,214	14,304
Total liquids (bbl/d)	**57,045**	**72,291**	**129,336**	53,248	49,905	103,153
Natural gas (mcf/d)	**41,412**	**100,850**	**142,262**	47,454	66,556	114,010
Total production (boe/d)	**63,948**	**89,100**	**153,048**	61,157	60,997	122,154
Production Mix						
Segment as a percent of total	**42%**	**58%**	**100%**	50%	50%	100%
Light oil and condensate	**19%**	**62%**	**44%**	26%	62%	44%
Heavy oil	**66%**	**—%**	**28%**	58%	—%	29%
NGL	**4%**	**20%**	**13%**	3%	20%	12%
Natural gas	**11%**	**18%**	**15%**	13%	18%	15%

Production averaged 153,048 boe/d in 2024 compared to 122,154 boe/d in 2023. Higher production in 2024 reflects the production contribution from the properties acquired from Ranger along with our successful development programs in both the U.S. and Canada.

In Canada, production increased to 63,948 boe/d in 2024 compared to 61,157 boe/d in 2023. The increase in production compared to 2023 is from strong well performance from our Clearwater asset at Peavine and from growth in our Pembina Duvernay which more than offset the disposition of 4,000 boe/d of light oil Viking assets in December 2023.

In the U.S., production was 89,100 boe/d in 2024 compared to 60,997 boe/d for 2023, which reflects a full year of production from the Merger with Ranger and the results of our successful development programs in the U.S.

Total production of 153,048 boe/d for 2024 was consistent with our revised annual guidance of approximately 153,000 boe/d. We expect production in 2025 to average 148,000 - 152,000 boe/d which reflects the December 2024 disposition of non-core heavy oil production from the Kerrobert Thermal asset which was producing approximately 2,000 boe/d when the sale was completed in December 2024.

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

Global benchmark prices for crude oil in 2024 were relatively consistent with 2023 as a result of global supply growth and stable demand which has resulted in a balanced crude oil market. The WTI benchmark price averaged US$75.72/bbl for 2024 compared to US$77.62/bbl for 2023.

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 typically trades at a premium to WTI as a result of access to global markets. The MEH benchmark averaged US$77.99/bbl during 2024, representing a premium of US$2.27/bbl relative to WTI, compared to US$79.29/bbl or a premium of US$1.67/bbl for 2023. The MEH benchmark traded at a higher premium to WTI in 2024 as a result of additional demand at the U.S. Gulf Coast.

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets from Western Canada. Differentials for Canadian oil prices relative to WTI fluctuate based on production and inventory levels in Western Canada.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $97.59/bbl for 2024 compared to $100.46/bbl for 2023. Edmonton par traded at a US$4.49/bbl discount to WTI in 2024 compared to a discount of US$3.18/bbl for 2023 which reflects the impact of increased U.S. production on Canadian light oil prices.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS benchmark price for 2024 averaged $83.56/bbl compared to $79.58/bbl for 2023. The WCS heavy oil differential to WTI was US$14.73/bbl in 2024 compared to US$18.65/bbl in 2023 which reflects the completion of the Trans Mountain pipeline expansion, which significantly increased the export capacity of Canadian heavy oil to the West Coast.

Natural Gas

North American production growth and mild winter weather during 2024 resulted in reduced demand for North American gas along with increased inventory levels which resulted in lower prices in 2024 relative to 2023.

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$2.27/mmbtu for 2024 compared to US$2.74/mmbtu for 2023.

In Canada, we receive natural gas pricing based on the AECO benchmark which continues to trade at a discount to NYMEX as a result of limited market access for Canadian natural gas production. The AECO benchmark averaged $1.44/mcf during 2024 which is lower than $2.93/mcf during 2023.

The following tables compare select benchmark prices and our average realized selling prices for the years ended December 31, 2024 and 2023.

	Years Ended December 31		
	2024	2023	Change
Benchmark Averages			
WTI oil (US$/bbl) (1)	**75.72**	77.62	(1.90)
MEH oil (US$/bbl) (2)	**77.99**	79.29	(1.30)
MEH oil differential to WTI (US$/bbl)	**2.27**	1.67	0.60
Edmonton par oil ($/bbl) (3)	**97.59**	100.46	(2.87)
Edmonton par oil differential to WTI (US$/bbl)	**(4.49)**	(3.18)	(1.31)
WCS heavy oil ($/bbl) (4)	**83.56**	79.58	3.98
WCS heavy oil differential to WTI (US$/bbl)	**(14.73)**	(18.65)	3.92
AECO natural gas price ($/mcf) (5)	**1.44**	2.93	(1.49)
NYMEX natural gas price (US$/mmbtu) (6)	**2.27**	2.74	(0.47)
CAD/USD average exchange rate	**1.3700**	1.3495	0.0205

(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.

	Years Ended December 31					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) (1)	**$ 96.08**	**$ 102.68**	**$ 101.50**	$ 100.34	$ 105.71	$ 104.13
Heavy oil, net of blending and other expense ($/bbl) (2)	**73.55**	**—**	**73.55**	66.19	—	66.19
NGL ($/bbl) (1)	**25.85**	**27.71**	**27.46**	30.38	27.55	27.96
Natural gas ($/mcf) (1)	**1.56**	**2.57**	**2.28**	2.83	3.15	3.02
Total sales, net of blending and other expense ($/boe) (2)	**$ 68.79**	**$ 71.60**	**$ 70.43**	$ 67.39	$ 74.27	$ 70.82

(1) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume 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 was $70.43/boe for 2024 compared to $70.82/boe for 2023. In Canada, our realized sales price of $68.79/boe for 2024 was higher than $67.39/boe for 2023 and our realized sales price in the U.S. of $71.60/boe in 2024 decreased from $74.27/boe in 2023. The increase in our realized price in Canada was a primarily result of higher WCS benchmark pricing and higher heavy oil production compared to 2023. The decrease in the realized price in the U.S. for 2024 was primarily a result of lower North American benchmark prices relative to 2023.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Lower benchmark prices resulted in our realized light oil and condensate price in 2024 was $96.08/bbl compared to $100.34/bbl in 2023. Our realized price represents a discount of $1.51/bbl to the Edmonton par benchmark compared to $0.12/bbl in 2023.

We compare the price received for our U.S. light oil and condensate production to the MEH benchmark. Our realized light oil and condensate price averaged $102.68/bbl for 2024 compared to $105.71/bbl for 2023. Expressed in U.S. dollars, our realized light oil and condensate price of US$74.95/bbl for 2024 was lower than US$78.33/bbl in 2023 and represents a discount to MEH of US$3.04/bbl for 2024 which is wider than the US$0.96/bbl discount in 2023. The realized discount to MEH for 2024 is consistent with expectations and reflects the realized pricing and additional Eagle Ford production acquired from Ranger.

Our realized heavy oil price, net of blending and other expense[1] for 2024 increased by $7.36/bbl from 2023, compared to a $3.98/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 in 2024 compared to 2023.

Our realized NGL price as a percentage of WTI will vary based on the product mix of our NGL volumes and changes in the market prices of the underlying products. Our realized NGL price[2] was $27.46/bbl in 2024 or 26% of WTI (expressed in Canadian dollars) which is consistent with $27.96/bbl or 27% of WTI (expressed in Canadian dollars) in 2023.

We compare our realized natural gas price in the U.S. to the NYMEX benchmark and to the AECO benchmark price in Canada. A portion of our natural gas sales in Canada and the U.S. are based on the respective daily index prices which fluctuate independently from the associated monthly index prices. Our realized natural gas price[2] in Canada was $1.56/mcf for 2024 compared to $2.83/mcf for 2023. In the U.S., our realized natural gas price was US$1.88/mcf for 2024 compared to US$2.33/mcf for 2023. The decrease in our realized gas price in Canada and the U.S. is consistent with the decreases in the representative AECO monthly and NYMEX monthly benchmark prices in 2024 compared to 2023.

(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, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.

PETROLEUM AND NATURAL GAS SALES

	Years Ended December 31					
	2024			2023		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 421,383**	**$ 2,063,677**	**$ 2,485,060**	$ 574,910	$ 1,454,213	$ 2,029,123
Heavy oil	**1,403,022**	**—**	**1,403,022**	1,081,549	—	1,081,549
NGL	**26,017**	**176,289**	**202,306**	23,174	122,823	145,997
Total liquids sales	**1,850,422**	**2,239,966**	**4,090,388**	1,679,633	1,577,036	3,256,669
Natural gas sales	**23,624**	**94,943**	**118,567**	49,388	76,564	125,952
Total petroleum and natural gas sales	**1,874,046**	**2,334,909**	**4,208,955**	1,729,021	1,653,600	3,382,621
Blending and other expense	**(263,943)**	**—**	**(263,943)**	(224,802)	—	(224,802)
Total sales, net of blending and other expense [1]	**$ 1,610,103**	**$ 2,334,909**	**$ 3,945,012**	$ 1,504,219	$ 1,653,600	$ 3,157,819

(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, of $3.9 billion for 2024 compared to $3.2 billion for 2023 which reflects a full year of production from the Merger with Ranger and increased production from our successful development programs.

In Canada, total sales, net of blending and other expense, of $1.6 billion for 2024 increased $105.9 million from $1.5 billion reported for 2023. The increase in our realized pricing for 2024 relative to 2023 resulted in a $32.8 million increase in total sales, net of blending and other expense while higher production contributed to a $73.1 million increase in total sales, net of blending and other expense, relative to 2023.

In the U.S., petroleum and natural gas sales of $2.3 billion in 2024 was $681.3 million higher than $1.7 billion reported for 2023. Total petroleum and natural gas sales increased $768.4 million due to higher production in 2024 relative to 2023 as a result of the Merger with Ranger. The impact of increased production was partially offset by lower realized pricing which resulted in a $87.1 million decrease in total petroleum and natural gas sales compared to 2023.

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 depending on 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 years ended December 31, 2024 and 2023.

	Years Ended December 31					
	2024			2023		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 261,205**	**$ 618,881**	**$ 880,086**	$ 213,148	$ 456,644	$ 669,792
Average royalty rate (1)(2)	**16.2%**	**26.5%**	**22.3%**	14.2%	27.6%	21.2%
Royalties per boe (3)	**$ 11.16**	**$ 18.98**	**$ 15.71**	$ 9.55	$ 20.51	$ 15.02

(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 2024 were $880.1 million or 22.3% of total sales, net of blending and other expense, compared to $669.8 million or 21.2% in 2023. Total royalty expense was higher in 2024 due to higher total sales, net of blending and other expense, relative to 2023. Our average royalty rate of 22.3% for 2024 was higher than 21.2% for 2023 as a higher proportion of our production was from the Eagle Ford in 2024 which has a higher royalty rate than our Canadian properties.

The average royalty rate in Canada was 16.2% in 2024, higher than 14.2% for 2023 as a result of production growth from our heavy oil properties which have a higher royalty rate relative to our light oil properties.

In the U.S., the average royalty rate was 26.5% for 2024 which is lower than 27.6% for 2023 due to production contributed by the acquired Ranger assets which have a lower royalty rate relative to our legacy non-operated Eagle Ford properties.

Our average royalty rate of 22.3% for 2024 was consistent with our annual guidance range of approximately 22.5% for 2024. We expect our average royalty rate to be approximately 23% for 2025.

OPERATING EXPENSE

	Years Ended December 31					
	2024			2023		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 336,069**	**$ 317,880**	**$ 653,949**	$ 368,605	$ 202,234	$ 570,839
Operating expense per boe (1)	**$ 14.36**	**$ 9.75**	**$ 11.67**	$ 16.51	$ 9.08	$ 12.80

(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 $653.9 million ($11.67/boe) in 2024 compared to $570.8 million ($12.80/boe) in 2023. Total operating expense increased in 2024 relative to 2023 while per boe operating costs were lower due to a full year of production from the properties acquired from Ranger which have lower per boe operating expenses.

In Canada, operating expense was $336.1 million ($14.36/boe) for 2024 compared to $368.6 million ($16.51/boe) for 2023. The decrease in total and per unit operating expense relative to 2023 reflects production growth at Peavine along with the disposition of high cost non-core Viking assets in Q4/2023.

In the U.S., operating expense was $317.9 million ($9.75/boe) for 2024 compared to $202.2 million ($9.08/boe) for 2023. Total operating expense in the U.S. was higher in 2024 relative to 2023 and reflects a full year of production from the properties acquired from Ranger. Per boe operating expense in the U.S., expressed in U.S. dollars, was US$7.12/boe for 2024 which is slightly higher than US$6.73/boe for 2023.

Operating expense of $11.67/boe for 2024 was consistent with our revised annual guidance of ~ $12.00/boe. We expect annual operating expense of $11.75 - $12.50/boe for 2025.

TRANSPORTATION EXPENSE

Transportation expense includes the costs to move production to the sales point. The largest component of transportation expense relates to the trucking of oil in Canada to pipeline and rail terminals which can vary depending on trucking rates and hauling distances as we seek to optimize sales prices. Transportation expense in our U.S. operations reflects the costs incurred to deliver our production to a centralized sales point via truck or pipeline.

The following table compares our transportation expense for the years ended December 31, 2024 and 2023.

	Years Ended December 31					
	2024			2023		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 84,211**	**$ 48,931**	**$ 133,142**	$ 64,325	$ 24,981	$ 89,306
Transportation expense per boe (1)	**$ 3.60**	**$ 1.50**	**$ 2.38**	$ 2.88	$ 1.12	$ 2.00

(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 $133.1 million ($2.38/boe) for 2024 compared to $89.3 million ($2.00/boe) for 2023. In Canada, total transportation expense and per unit costs were higher in 2024 relative to 2023 as a result of additional heavy oil production relative to 2023. Transportation expense in the U.S. is higher in 2024 relative to 2023 which reflects a full year of operations on our Eagle Ford properties acquired from Ranger.

Transportation expense of $2.38/boe in 2024 was consistent with our revised annual guidance of approximately $2.45/boe for 2024. We expect annual transportation expense of $2.40 - $2.55/boe for 2025 which reflects production growth from our heavy oil properties.

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 $263.9 million for 2024 compared to $224.8 million for 2023. Higher blending and other expense is primarily a result of increased heavy oil production and pipeline shipments in 2024 relative to 2023, partially offset by a decrease in the cost of condensate purchased for blending in 2024 compared to 2023.

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 entered. The following table summarizes the results of our financial derivative contracts for the years ended December 31, 2024 and 2023.

	Years Ended December 31		
($ thousands)	**2024**	2023	Change
Realized financial derivatives (loss) gain			
Crude oil	**$ (9,186)**	$ 35,687	$ (44,873)
Natural gas	**10,633**	525	10,108
Total	**$ 1,447**	$ 36,212	$ (34,765)
Unrealized financial derivatives gain (loss)			
Crude oil	**$ 7,548**	$ (17,674)	$ 25,222
Natural gas	**(6,894)**	6,157	(13,051)
Total	**$ 654**	$ (11,517)	$ 12,171
Total financial derivatives (loss) gain			
Crude oil	**$ (1,638)**	$ 18,013	$ (19,651)
Natural gas	**3,739**	6,682	(2,943)
Total	**$ 2,101**	$ 24,695	$ (22,594)

We recorded a financial derivatives gain of $2.1 million for 2024 compared to a gain of $24.7 million for 2023. The realized financial derivatives gain of $1.4 million for 2024 resulted from $10.6 million of gains on natural gas contracts and $9.2 million of losses on crude oil contracts. The unrealized financial derivatives gain of $0.7 million for 2024 resulted from a $7.5 million gain on crude oil contracts partially offset by a $6.9 million loss on natural gas contracts. The fair value of our financial derivative contracts resulted in a net asset of $23.9 million at December 31, 2024 compared to a net asset of $23.3 million at December 31, 2023.

Refer to Note 18 of the consolidated financial statements for a complete listing of our outstanding contracts at March 4, 2025.

OPERATING NETBACK

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the years ended December 31, 2024 and 2023.

	Years Ended December 31					
	2024			2023		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**63,948**	**89,100**	**153,048**	61,157	60,997	122,154
Operating netback:						
Total sales, net of blending and other expense [(1)]	**$ 68.79**	**$ 71.60**	**$ 70.43**	$ 67.39	$ 74.27	$ 70.82
Less:						
Royalties [(2)]	**(11.16)**	**(18.98)**	**(15.71)**	(9.55)	(20.51)	(15.02)
Operating expense [(2)]	**(14.36)**	**(9.75)**	**(11.67)**	(16.51)	(9.08)	(12.80)
Transportation expense [(2)]	**(3.60)**	**(1.50)**	**(2.38)**	(2.88)	(1.12)	(2.00)
Operating netback [(1)]	**$ 39.67**	**$ 41.37**	**$ 40.67**	$ 38.45	$ 43.56	$ 41.00
Realized financial derivatives gain (loss) [(3)]	**—**	**—**	**0.03**	—	—	0.81
Operating netback after financial derivatives [(1)]	**$ 39.67**	**$ 41.37**	**$ 40.70**	$ 38.45	$ 43.56	$ 41.81

(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 $40.67/boe for 2024 was consistent with $41.00/boe for 2023 as our realized price net of royalties was relatively consistent in both periods. Total operating expense and transportation expense of $14.05/boe for 2024 was lower than $14.80/boe in 2023 which reflects lower costs on the operated Eagle Ford properties acquired from Ranger. Our operating netback net of realized gains and losses on financial derivatives was $40.70/boe for 2024 compared to $41.81/boe for 2023.

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 years ended December 31, 2024 and 2023.

	Years Ended December 31		
($ thousands except for per boe)	**2024**	2023	Change
Gross general and administrative expense	**$ 107,743**	$ 84,096	$ 23,647
Overhead recoveries	**(25,997)**	(14,307)	(11,690)
General and administrative expense	**$ 81,746**	$ 69,789	$ 11,957
General and administrative expense per boe [(1)]	**$ 1.46**	$ 1.57	$ (0.11)

(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 $81.7 million ($1.46/boe) for 2024 compared to $69.8 million ($1.57/boe) for 2023. G&A expense was higher relative to 2023 primarily due to staffing costs associated with the personnel retained following the Merger with Ranger.

G&A expense of $81.7 million ($1.46/boe) for 2024 is consistent with our revised annual guidance of $85 million ($1.52/boe). We expect annual G&A expense of $90 million ($1.64/boe) for 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 years ended December 31, 2024 and 2023.

	Years Ended December 31		
($ thousands except for per boe)	**2024**	2023	Change
Interest on credit facilities	**$ 55,498**	$ 56,713	$ (1,215)
Interest on long-term notes	**148,968**	102,426	46,542
Interest on lease obligations	**1,638**	684	954
Cash interest	**$ 206,104**	$ 159,823	$ 46,281
Amortization of debt issue costs	**16,694**	11,944	4,750
Accretion of asset retirement obligations	**21,226**	20,406	820
Early redemption expense	**24,350**	—	24,350
Financing and interest expense	**$ 268,374**	$ 192,173	$ 76,201
Cash interest per boe (1)	**$ 3.68**	$ 3.58	$ 0.10
Financing and interest expense per boe (1)	**$ 4.79**	$ 4.31	$ 0.48

(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 $268.4 million ($4.79/boe) in 2024 compared to $192.2 million ($4.31/boe) in 2023. Higher interest costs in 2024 relative to 2023 are primarily a result of the additional debt outstanding after the Merger with Ranger and also includes costs incurred for the early redemption of the 8.75% senior notes on April 1, 2024.

Cash interest of $206.1 million ($3.68/boe) in 2024 was higher than $159.8 million ($3.58/boe) in 2023 and is primarily a result of additional debt outstanding in 2024 after the Merger which included the issuance of US$800.0 million aggregate principal amount of long-term notes. The weighted average interest rate applicable on our credit facilities was 7.6% in 2024 compared to 7.4% in 2023.

Accretion of asset retirement obligations of $21.2 million for 2024 was consistent with $20.4 million for 2023. Accretion of debt issues costs was higher in 2024 relative to 2023 due to the costs associated with the debt issued in conjunction with the Merger. In Q2/2024, we refinanced our remaining 8.75% senior notes with US$575 million of 7.375% notes and we recorded $24.4 million of early redemption expense.

Cash interest of $206.1 million ($3.68/boe) for 2024 was consistent with our revised annual guidance of $200 million ($3.58/boe). We expect cash interest to be $180 million ($3.29/boe) for 2025 which reflects lower debt outstanding relative to 2024.

EXPLORATION AND EVALUATION EXPENSE

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense was $0.8 million for 2024 compared to $8.9 million for 2023.

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 years ended December 31, 2024 and 2023.

	Years Ended December 31		
($ thousands except for per boe)	**2024**	2023	Change
Depletion and depreciation	**$ 1,385,910**	$ 1,047,904	$ 338,006
Depletion and depreciation per boe(1)	**$ 24.74**	$ 23.50	$ 1.24

(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 $1.4 billion ($24.74/boe) for 2024 compared to $1.0 billion ($23.50/boe) for 2023. Total depletion and depreciation expense as well as the depletion and depreciation rate per boe were higher in 2024 relative to 2023 due to a full year of depletion on the assets acquired from Ranger which have a higher depletion rate than our other properties. The effect of the Merger was partially offset by an impairment loss of $833.7 million recorded at December 31, 2023.

IMPAIRMENT

2024 Impairment

At December 31, 2024, there were no indicators of impairment or impairment reversal for oil and gas properties in any of the Company's CGUs.

2023 Impairment

At December 31, 2023, we identified indicators of impairment for oil and gas properties in our legacy non-operated Eagle Ford cash-generating unit ("CGU") due to changes in our reserves volumes and in our Viking CGU due to changes in reserves along with a loss recorded on disposition of an asset within the CGU. The recoverable amounts for the two CGUs were not sufficient to support their carrying values which resulted in an impairment of $833.7 million recorded at December 31, 2023.

The following table summarizes the recoverable amount and impairment for each of the two CGUs at December 31, 2023 and demonstrates the sensitivity of the impairment to reasonably possible changes in key assumptions inherent in the calculation.

($ thousands)	Recoverable amount	Impairment loss	Change in discount rate of 1%	Change in oil price of $2.50/ bbl	Change in gas price of $0.25/ mcf
Viking CGU	$ 606,290	$ 184,000	$ 26,500	$ 53,000	$ 3,500
Eagle Ford Non-operated CGU (1)	1,429,658	649,662	71,300	107,600	25,700

(1) There were no indicators of impairment identified for the Eagle Ford Operated CGU which includes the assets acquired from Ranger.

SHARE-BASED COMPENSATION EXPENSE

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

We recorded SBC expense of $17.9 million for 2024 compared to $37.7 million for 2023. SBC expense for 2024 reflects a decrease in the Company's share price which contributed to lower SBC expense relative to 2023 which includes $16.2 million of non-cash expense related to awards assumed and settled in Baytex common shares in conjunction with the Merger with Ranger.

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.

	Years Ended December 31		
($ thousands except for exchange rates)	**2024**	2023	Change
Unrealized foreign exchange loss (gain)	**$ 153,930**	$ (14,300)	$ 168,230
Realized foreign exchange loss	**1,965**	3,452	(1,487)
Foreign exchange loss (gain)	**$ 155,895**	$ (10,848)	$ 166,743
CAD/USD exchange rates:			
At beginning of period	**1.3205**	1.3534	
At end of period	**1.4405**	1.3205	

We recorded a foreign exchange loss of $155.9 million for 2024 compared to a gain of $10.8 million for 2023.

The unrealized foreign exchange loss of $153.9 million for 2024 is due to an increase in the reported amount of our U.S. dollar denominated long-term notes and credit facilities. The $153.9 million loss is the result of the weakening of the Canadian dollar relative to the U.S. dollar at December 31, 2024 compared to December 31, 2023. The unrealized foreign exchange gain of $14.3 million for 2023 is primarily related to changes in the reported amount of our long-term notes due to a strengthening of the Canadian dollar relative to the U.S. dollar at December 31, 2023 compared to December 31, 2022.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange loss of $2.0 million for 2024 compared to a loss of $3.5 million for 2023.

INCOME TAXES

	Years Ended December 31		
($ thousands)	**2024**	2023	Change
Current income tax expense	**$ 21,766**	$ 14,403	$ 7,363
Deferred income tax expense (recovery)	**114,927**	(297,629)	412,556
Total income tax expense (recovery)	**$ 136,693**	$ (283,226)	$ 419,919

Current income tax expense was $21.8 million for 2024 compared to $14.4 million recorded in 2023. Current income tax is higher in 2024 due to higher taxes incurred on the repatriation of earnings from our U.S. operations. We recorded deferred income tax expense of $114.9 million for 2024 compared to a deferred income tax recovery of $297.6 million for 2023. The deferred tax expense in 2024 reflects income generated on our U.S. operations and income, before losses on foreign exchange, generated on our Canadian operations. The deferred tax recovery recorded in 2023 was primarily related to the effects of the transaction structuring for the Merger in 2023 along with the effects of impairment losses on our Canadian and U.S. assets, partially offset by income generated on our Canadian and U.S. operations 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 (described below) 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.

The following table summarizes our Canadian and Foreign tax pools.

Canadian Tax Pools *($ thousands)*	**December 31, 2024**	December 31, 2023
Canadian oil and natural gas property expenditures	**$ 282,604**	$ 203,406
Canadian development expenditures	**516,475**	518,788
Undepreciated capital costs	**282,056**	280,564
Non-capital losses	**447,993**	643,697
Financing costs and other	**132,163**	98,816
Total Canadian tax pools	**$ 1,661,291**	$ 1,745,271
Foreign Tax Pools *($ thousands)*		
Depletion	**$ 1,750,498**	$ 1,893,577
Intangible drilling costs	**191,648**	$ 352,021
Tangibles	**208,298**	213,372
Net operating losses	**2,884,406**	2,558,472
Other	**627,156**	468,554
Total Foreign tax pools	**$ 5,662,006**	$ 5,485,996

NET INCOME (LOSS) AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income or loss for the years ended December 31, 2024 and 2023 are set forth in the following table.

	Years Ended December 31		
($ thousands)	**2024**	2023	Change
Petroleum and natural gas sales	**$ 4,208,955**	$ 3,382,621	$ 826,334
Royalties	**(880,086)**	(669,792)	(210,294)
Revenue, net of royalties	**3,328,869**	2,712,829	616,040
Expenses			
Operating	**(653,949)**	(570,839)	(83,110)
Transportation	**(133,142)**	(89,306)	(43,836)
Blending and other	**(263,943)**	(224,802)	(39,141)
Operating netback [1]	**$ 2,277,835**	$ 1,827,882	$ 449,953
General and administrative	**(81,746)**	(69,789)	(11,957)
Cash interest	**(206,104)**	(159,823)	(46,281)
Realized financial derivatives gain	**1,447**	36,212	(34,765)
Realized foreign exchange loss	**(1,965)**	(3,452)	1,487
Other income (expense)	**6,689**	(815)	7,504
Current income tax expense	**(21,766)**	(14,403)	(7,363)
Cash share-based compensation	**(17,872)**	(21,462)	3,590
Adjusted funds flow [2]	**$ 1,956,518**	$ 1,594,350	$ 362,168
Transaction costs	**(1,539)**	(49,045)	47,506
Exploration and evaluation	**(779)**	(8,896)	8,117
Depletion and depreciation	**(1,385,910)**	(1,047,904)	(338,006)
Non-cash share-based compensation	**—**	(16,237)	16,237
Non-cash financing and interest	**(62,270)**	(32,350)	(29,920)
Non-cash other income	**—**	1,271	(1,271)
Unrealized financial derivatives gain (loss)	**654**	(11,517)	12,171
Unrealized foreign exchange (loss) gain	**(153,930)**	14,300	(168,230)
Loss on dispositions	**(1,220)**	(141,295)	140,075
Impairment	**—**	(833,662)	833,662
Deferred income tax (expense) recovery	**(114,927)**	297,629	(412,556)
Net income (loss)	**$ 236,597**	$ (233,356)	$ 469,953

(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 $2.0 billion for 2024 compared to $1.6 billion for 2023. The $362.2 million increase in adjusted funds flow for 2024 reflects a full year of operations following the Merger with Ranger. Cash interest and general and administrative expenses were also higher for 2024 due to the additional debt outstanding and additional staffing levels following the Merger.

We reported net income of $236.6 million for 2024 compared to a net loss of $233.4 million for 2023. Net income for 2024 reflects additional depletion expense and unrealized foreign exchange loss relative to the net loss in 2023 which included an impairment loss.

OTHER COMPREHENSIVE INCOME (LOSS)

Other comprehensive income (loss) reflects the foreign currency translation adjustment on our U.S. net assets which is not recognized in net income or loss. The foreign currency translation gain of $402.3 million for 2024 relates to the change in value of our U.S. net assets and is due to the weakening of the Canadian dollar relative to the U.S. dollar at December 31, 2024 compared to December 31, 2023. The CAD/USD exchange rate was 1.4405 CAD/USD at December 31, 2024 compared to 1.3205 CAD/USD at December 31, 2023.

CAPITAL EXPENDITURES

Capital expenditures for the years ended December 31, 2024 and 2023 are summarized as follows.

	Years Ended December 31					
	2024			2023		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 399,817**	**$ 674,900**	**$ 1,074,717**	$ 393,127	$ 492,030	$ 885,157
Facilities and other	**89,669**	**92,247**	**181,916**	70,071	57,559	127,630
Exploration and development expenditures	**$ 489,486**	**$ 767,147**	**$ 1,256,633**	$ 463,198	$ 549,589	$ 1,012,787
Property acquisitions	**48,889**	**3,526**	**52,415**	20,023	18,891	38,914
Proceeds from dispositions	**(41,149)**	**(5,346)**	**(46,495)**	(160,256)	—	(160,256)

Exploration and development expenditures were $1.26 billion for 2024 compared to $1.0 billion for 2023. The increase for 2024 reflects increased development activity in Canada along with development activity on our operated Eagle Ford properties acquired from Ranger.

In Canada, exploration and development expenditures were $489.5 million in 2024 compared to $463.2 million in 2023. Drilling and completion spending of $399.8 million in 2024 was very similar to $393.1 million in 2023 with similar activity levels. We also invested $89.7 million on facilities and other expenditures, completed the acquisition of 30.75 net sections of Duvernay lands adjacent to our existing acreage for $29.8 million in Q1/2024 and sold our Kerrobert Thermal assets for $41.5 million in Q4/2024.

Total U.S. exploration and development expenditures were $767.1 million for 2024 compared to $549.6 million for 2023. Exploration and development expenditures for 2024 reflect a full year of development on the operated properties acquired from Ranger.

Total exploration and development expenditures of $1.26 billion for 2024 were consistent with our revised annual guidance of approximately $1.25 billion. We expect annual exploration and development expenditures of $1.2 - $1.3 billion for 2025.

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 transactions. We strive to actively manage our capital structure in response to changes in economic conditions. At December 31, 2024, 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 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 December 31, 2024 was 5% lower than $2.5 billion at December 31, 2023 which reflects our allocation of free cash flow to debt repayment in 2024. Free cash flow of $655.6 million generated in 2024 was allocated to debt repayment along with $289.9 million of shareholder returns including share buybacks and quarterly dividends. The change in net debt also reflects $49.7 million of debt issuance costs incurred during 2024 along with a $176.9 million foreign exchange loss on our U.S. dollar denominated net debt due to a weaker Canadian dollar at December 31, 2024. At December 31, 2024, our net debt on a U.S. dollar denominated based was reduced by US$241 million or 13% relative to December 31, 2023.

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

In June 2024, we renewed our normal course issuer bid ("NCIB") to repurchase our common shares as part of our shareholder return framework. In 2024 we repurchased 48.4 million common shares at an average price of $4.50 per share for total consideration of $217.9 million.

Our shareholder returns framework includes a quarterly dividend. On January 2, 2025, we paid a quarterly cash dividend of $0.0225 per share to shareholders of record. On March 4, 2025, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on April 1, 2025 for shareholders on record as at March 14, 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.”

Credit Facilities

At December 31, 2024, we had $341.2 million of principal amount outstanding under our revolving credit facilities which total US$1.1 billion ($1.6 billion) (the "Credit Facilities"). The Credit Facilities are secured and are comprised of a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex and a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. On May 9, 2024, we extended the maturity of the Credit Facilities from April 1, 2026 to May 9, 2028. There were no changes to the loan balances or financial covenants as a result of the amendment. As part of the amendment, borrowing in Canadian funds previously based on the banker's acceptance rate has been replaced with borrowings based on the Canadian Overnight Repo Rate Average ("CORRA").

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 Canadian Prime Rate, U.S. Base 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 U.S. Base Rate or SOFR, plus applicable margins.

The weighted average interest rate on the Credit Facilities was 7.6% for 2024, which is consistent with 7.4% for 2023.

At December 31, 2024, Baytex had $5.8 million of outstanding letters of credit (December 31, 2023 - $5.6 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 December 31, 2024.

Covenant Description	Position as at December 31, 2024	Covenant
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0.2:1.0**	3.5:1.0
Interest Coverage (3) (Minimum Ratio)	**10.7:1.0**	3.5:1.0
Total Debt (4) to Bank EBITDA (2) (Maximum Ratio)	**1.1:1.0**	4.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the credit facilities and other secured obligations identified in the credit facility agreement. As at December 31, 2024, the Company's Senior Secured Debt totaled $345.9 million.

(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended December 31, 2024 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 expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expenses for the twelve months ended December 31, 2024 were $204.5 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, other long-term liabilities, dividends payable, share-based compensation liability, asset retirement obligations, leases, deferred income tax liabilities, and financial derivative liabilities. At December 31, 2024 our Total Debt was $2.3 billion.

Long-Term Notes

At December 31, 2024 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. At December 31, 2024 there was US$800 million aggregate principal amount of the 8.50% Senior Notes outstanding.

On April 1, 2024, we issued US$575 million aggregate principal amount of senior unsecured notes due 2032 ("7.375% Senior Notes"). The 7.375% Senior Notes were priced at 99.266% of par to yield 7.500% per annum, bear interest at a rate of 7.375% per annum and mature on March 15, 2032. 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. Proceeds from the 7.375% Senior Notes were used to redeem the remaining US$409.8 million aggregate principal amount of the outstanding 8.75% Senior Notes at 104.375% of par value, pay the related fees and expenses associated with the offering, and repay a portion of the debt outstanding on our Credit Facilities. At December 31, 2024 there was US$575 million aggregate principal amount of the 7.375% Senior Notes outstanding.

Baytex is subject to certain financial and commercial covenants related to its Credit Facilities and long-term notes. 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.

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 year ended December 31, 2024, we issued 0.3 million common shares pursuant to our share-based compensation program. As at December 31, 2024, we had 773.6 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 year ended December 31, 2024, we repurchased 48.4 million common shares under our normal course issuer bid ("NCIB") at an average price of $4.50 per share for total consideration of $217.9 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.

In 2024, the Government of Canada introduced a 2% federal tax on equity repurchases with an effective date of January 1, 2024. We recorded a $4.3 million charge to shareholders' capital, related to the federal tax on equity repurchases for the year ended December 31, 2024.

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 December 31, 2024 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	**$ 341,207**	$ —	$ —	$ 341,207	$ —
Long-term notes - principal	**1,980,619**	—	—	—	1,980,619
Interest on long-term notes (1)	**962,531**	159,035	318,069	318,069	167,358
Lease obligations - principal	**29,089**	10,786	9,175	7,200	1,928
Processing agreements	**5,917**	948	1,239	543	3,187
Transportation agreements	**168,767**	54,909	84,742	17,877	11,239
Total	**$ 3,488,130**	$ 225,678	$ 413,225	$ 684,896	$ 2,164,331

(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.

FOURTH QUARTER OPERATING AND FINANCIAL RESULTS

	Three Months Ended December 31					
	2024			2023		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total daily production						
Light oil and condensate (bbl/d)	**11,568**	**53,093**	**64,661**	14,143	55,981	70,124
Heavy oil (bbl/d)	**42,227**	**—**	**42,227**	39,569	—	39,569
NGL (bbl/d)	**3,519**	**17,689**	**21,208**	2,937	20,223	23,160
Total liquids (bbl/d)	**57,314**	**70,782**	**128,096**	56,649	76,204	132,853
Natural gas (mcf/d)	**48,113**	**100,679**	**148,792**	48,573	116,548	165,121
Total production (boe/d)	**65,332**	**87,562**	**152,894**	64,744	95,629	160,373
Operating netback ($/boe)						
Light oil and condensate ($/bbl) [1]	**$ 93.66**	**$ 97.05**	**$ 96.44**	$ 99.93	$ 105.83	$ 104.64
Heavy oil, net of blending and other expense ($/bbl) [2]	**70.05**	**—**	**70.05**	62.48	—	62.48
NGL ($/bbl) [1]	**26.06**	**29.70**	**29.09**	27.38	26.68	26.76
Natural gas ($/mcf) [1]	**1.43**	**3.02**	**2.50**	2.40	3.07	2.87
Total sales, net of blending and other per boe [2]	**$ 64.31**	**$ 68.31**	**$ 66.60**	$ 63.06	$ 71.34	$ 68.00
Royalties per boe [3]	**(10.05)**	**(18.16)**	**(14.69)**	(9.69)	(19.42)	(15.49)
Operating expense per boe [3]	**(13.12)**	**(8.29)**	**(10.36)**	(15.61)	(8.17)	(11.17)
Transportation expense per boe [3]	**(3.59)**	**(1.43)**	**(2.35)**	(3.02)	(1.33)	(2.02)
Operating netback per boe [2]	**$ 37.55**	**$ 40.43**	**$ 39.20**	$ 34.74	$ 42.42	$ 39.32
Financial						
Petroleum and natural gas sales	**$ 466,706**	**$ 550,311**	**$ 1,017,017**	$ 437,889	$ 627,626	$ 1,065,515
Royalties	**(60,396)**	**(146,279)**	**(206,675)**	(57,746)	(170,824)	(228,570)
Revenue, net of royalties	**$ 406,310**	**$ 404,032**	**$ 810,342**	$ 380,143	$ 456,802	$ 836,945
Operating	**(78,878)**	**(66,812)**	**(145,690)**	(93,006)	(71,867)	(164,873)
Transportation	**(21,595)**	**(11,515)**	**(33,110)**	(18,005)	(11,739)	(29,744)
Blending and other	**(80,148)**	**—**	**(80,148)**	(62,296)	—	(62,296)
Operating netback [2]	**$ 225,689**	**$ 325,705**	**$ 551,394**	$ 206,836	$ 373,196	$ 580,032
General and administrative	**—**	**—**	**(20,433)**	—	—	(22,280)
Cash interest	**—**	**—**	**(48,769)**	—	—	(56,698)
Realized financial derivatives gain (loss)	**—**	**—**	**(2,115)**	—	—	12,377
Other	**—**	**—**	**(18,191)**	—	—	(11,283)
Adjusted funds flow [4]	**$ 225,689**	**$ 325,705**	**$ 461,886**	$ 206,836	$ 373,196	$ 502,148
Net income (loss)	**$ 113,551**	**$ 113,172**	**$ (38,477)**	$ (255,238)	$ (531,505)	$ (625,830)
Exploration and development expenditures	**$ 108,971**	**$ 89,206**	**$ 198,177**	$ 75,137	$ 124,077	$ 199,214
Property acquisitions	**12,305**	**316**	**12,621**	15,032	18,891	33,923
Proceeds from dispositions	**(41,517)**	**(822)**	**(42,339)**	(159,745)	—	(159,745)
Net debt [4]			**$ 2,417,172**			$ 2,534,287

(1) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume 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.
(3) Calculated as royalties expense, operating expense or transportation expense divided by barrels of oil equivalent production volume for the applicable period.
(4) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

	Three Months Ended December 31		
	2024	2023	Change
Benchmark Averages			
WTI oil (US$/bbl) (1)	**70.27**	78.32	(8.05)
MEH oil (US$/bbl) (2)	**72.40**	80.62	(8.22)
MEH oil differential to WTI (US$/bbl)	**2.13**	2.30	(0.17)
Edmonton par oil ($/bbl) (3)	**94.98**	99.72	(4.74)
Edmonton par oil differential to WTI (US$/bbl)	**(2.39)**	(5.10)	2.71
WCS heavy oil ($/bbl) (4)	**80.77**	76.86	3.91
WCS heavy oil differential to WTI (US$/bbl)	**(12.54)**	(21.88)	9.34
AECO natural gas price ($/mcf) (5)	**1.46**	2.66	(1.20)
NYMEX natural gas price (US$/mmbtu) (6)	**2.79**	2.88	(0.09)
CAD/USD average exchange rate	**1.3992**	1.3619	0.0373

(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.

Our operating and financial results for Q4/2024 reflect the successful execution of our 2024 development programs in the U.S. and Canada. We invested $198.2 million on exploration and development expenditures in Q4/2024 and delivered production of 152,894 boe/d. Free cash flow(1) was $254.8 million in Q4/2024 which reflects the disciplined execution of our development programs.

In Canada, production averaged 65,332 boe/d in Q4/2024 which was 588 boe/d higher than 64,744 boe/d reported for Q4/2023 as a result of our successful Clearwater development program at Peavine. Higher benchmark pricing for heavy oil resulted in a realized price of $64.31/boe for Q4/2024 which was $1.25/boe higher than $63.06/boe for Q4/2023. The WCS heavy oil differential narrowed to US$12.54/bbl for Q4/2024 compared to US$21.88/bbl for Q4/2023. Increased production and higher benchmark prices for heavy oil were the main factors that resulted in an operating netback(1) of $225.7 million ($37.55/boe) for Q4/2024 which was $18.9 million ($2.81/boe) higher than $206.8 million ($34.74/boe) reported for Q4/2023. Exploration and development expenditures were $109.0 million in Q4/2024 compared to $75.1 million in Q4/2023.

In the U.S., production averaged 87,562 boe/d for Q4/2024 which is 8,067 boe/d lower than 95,629 boe/d reported for Q4/2023 which reflects reduced activity in Q4/2024. The MEH benchmark averaged US$72.40/bbl in Q4/2024 which was US$8.22/boe lower than US$80.62/bbl during Q4/2023 and resulted in a realized price of $68.31/boe which was $3.03/boe lower than our realized price of $71.34/boe in Q4/2023. Operating netback of $325.7 million ($40.43/boe) was $47.5 million ($1.99/boe) lower than $373.2 million ($42.42/boe) for Q4/2023 which reflects lower benchmark commodity prices and lower production in Q4/2024 compared to Q4/2023. Exploration and development expenditures were $89.2 million in Q4/2024 which were lower compared to Q4/2023 when we spent $124.1 million.

We generated adjusted funds flow(2) of $461.9 million in Q4/2024 which is $40.3 million lower than $502.1 million in Q4/2023. The decrease in adjusted funds flow for Q4/2024 reflects lower production and lower benchmark pricing compared to Q4/2023. We recorded realized financial derivatives losses of $2.1 million in Q4/2024 compared to gains of $12.4 million in Q4/2023. G&A expense of $20.4 million in Q4/2024 was lower than $22.3 million in Q4/2023. Interest expense of $48.8 million in Q4/2024 was $7.9 million lower than $56.7 million for Q4/2023 which reflects lower amounts outstanding under the credit facilities. Net debt(2) was $2.4 billion at Q4/2024 compared to $2.5 billion in Q4/2023.

We recorded a net loss of $38.5 million in Q4/2024 compared to net loss of $625.8 million in Q4/2023. In Q4/2023 we recorded an $833.7 million impairment loss. In Q4/2024 we recorded a $120.4 million unrealized foreign exchange loss due to due to changes in the reported amount of our U.S. dollar denominated long-term notes and credit facilities as a result of a weakening Canadian dollar in compared to a gain of $43.6 million recorded in Q4/2023.

(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.

QUARTERLY FINANCIAL INFORMATION

	2024				2023			
($ thousands, except per common share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	**1,017,017**	1,074,623	1,133,123	984,192	1,065,515	1,163,010	598,760	555,336
Net (loss) income	**(38,477)**	185,219	103,898	(14,043)	(625,830)	127,430	213,603	51,441
Per common share - basic	**(0.05)**	0.23	0.13	(0.02)	(0.75)	0.15	0.37	0.09
Per common share - diluted	**(0.05)**	0.23	0.13	(0.02)	(0.75)	0.15	0.36	0.09
Adjusted funds flow (1)	**461,886**	537,947	532,839	423,846	502,148	581,623	273,590	236,989
Per common share - basic	**0.59**	0.68	0.65	0.52	0.60	0.68	0.47	0.43
Per common share - diluted	**0.59**	0.67	0.65	0.52	0.60	0.68	0.47	0.43
Free cash flow (2)	**254,838**	220,159	180,673	(88)	290,785	158,440	96,313	(1,918)
Per common share - basic	**0.33**	0.28	0.22	—	0.35	0.19	0.17	—
Per common share - diluted	**0.33**	0.28	0.22	—	0.35	0.18	0.16	—
Cash flows from operating activities	**468,865**	550,042	505,584	383,773	474,452	444,033	192,308	184,938
Per common share - basic	**0.60**	0.69	0.62	0.47	0.57	0.52	0.33	0.34
Per common share - diluted	**0.60**	0.69	0.62	0.47	0.57	0.52	0.33	0.34
Dividends declared	**17,598**	17,732	18,161	18,494	18,381	19,138	—	—
Per common share – basic	**0.0225**	0.0225	0.0225	0.0225	0.0225	0.0225	—	—
Exploration and development expenditures	**198,177**	306,332	339,573	412,551	199,214	409,191	170,704	233,626
Canada	**108,971**	120,473	101,916	158,126	75,137	107,053	96,403	184,606
U.S.	**89,206**	185,859	237,657	254,425	124,077	302,138	74,301	49,020
Property acquisitions	**12,621**	1,042	3,349	35,403	33,923	4,277	(62)	506
Proceeds from dispositions	**(42,339)**	(1,436)	(2,695)	(25)	(159,745)	(226)	(50)	(235)
Net debt (1)	**2,417,172**	2,493,269	2,639,014	2,639,841	2,534,287	2,824,348	2,814,844	995,170
Total assets (3)	**7,759,745**	7,614,157	7,770,926	7,717,495	7,460,931	8,946,181	8,617,444	5,180,059
Common shares outstanding	**773,590**	787,328	804,977	821,322	821,681	845,360	862,192	545,553
Daily production								
Total production (boe/d)	**152,894**	154,468	154,194	150,620	160,373	150,600	89,761	86,760
Canada (boe/d)	**65,332**	64,668	63,688	62,081	64,744	63,289	55,874	60,651
U.S. (boe/d)	**87,562**	89,800	90,506	88,540	95,629	87,311	33,887	26,109
Benchmark prices								
WTI oil (US$/bbl)	**70.27**	75.10	80.57	76.96	78.32	82.26	73.78	76.13
WCS heavy ($/bbl)	**80.77**	83.98	91.72	77.73	76.86	93.02	78.85	69.44
Edmonton Light ($/bbl)	**94.98**	97.91	105.30	92.16	99.72	107.93	95.13	99.04
CAD/USD avg exchange rate	**1.3992**	1.3636	1.3684	1.3488	1.3619	1.3410	1.3431	1.3520
AECO gas ($/mcf)	**1.46**	0.81	1.44	2.05	2.66	2.39	2.35	4.34
NYMEX gas (US$/mmbtu)	**2.79**	2.16	1.89	2.24	2.88	2.55	2.10	3.42
Total sales, net of blending and other expense ($/boe) (2)	**66.60**	71.97	75.93	67.12	68.00	80.34	66.82	63.48
Royalties ($/boe) (4)	**(14.69)**	(15.75)	(17.14)	(15.26)	(15.49)	(17.33)	(13.21)	(11.94)
Operating expense ($/boe) (4)	**(10.36)**	(11.76)	(11.95)	(12.65)	(11.17)	(12.57)	(14.62)	(14.40)
Transportation expense ($/boe) (4)	**(2.35)**	(2.60)	(2.37)	(2.18)	(2.02)	(2.02)	(1.78)	(2.18)
Operating netback ($/boe) (2)	**39.20**	41.86	44.47	37.03	39.32	48.42	37.21	34.96
Financial derivatives gain (loss) ($/boe) (4)	**(0.15)**	0.02	(0.16)	0.40	0.84	0.15	2.00	0.69
Operating netback after financial derivatives ($/boe) (2)	**39.05**	41.88	44.31	37.43	40.16	48.57	39.21	35.65

(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) Previously disclosed amounts have been revised to conform with current period presentation.

(4) Calculated as royalties expense, operating expenses, transportation expense or financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

Our results for the previous eight quarters reflect the disciplined execution of our capital programs while oil and natural gas prices have fluctuated. Production steadily increased from 86,760 boe/d in Q1/2023 to 152,894 boe/d in Q4/2024 which reflects strong well performance from our development programs in Canada and the U.S. along with the production contribution from the Merger with Ranger.

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 $66.60/boe for Q4/2024 reflects lower crude oil prices due to concerns over weaker demand, higher inventories and slowing global economic activity.

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 $461.9 million and cash flows from operating activities of $468.9 million for Q4/2024 reflect strong production results from our development plans in the U.S. and Canada.

Net debt can fluctuate 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) increased to $2.4 billion at Q4/2024 from $1.0 billion at Q1/2023 as a result of additional $1.8 billion of debt used to fund the Merger which closed in Q2/2023. The change in net debt also reflects free cash flow(2) of $1.2 billion generated in the period since Q1/2023, along with $549.3 million allocated to shareholder returns.

(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 its first standards which are aligned with the ISSB release and include suggestions for Canadian-specific modifications. The Canadian Securities Administrators have also issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters which sets forth additional reporting requirements for Canadian Public Companies. 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 December 31, 2024, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information available, including considerations related to various regulatory and legislative requirements, to the Company at the time of financial statement preparation. Actual results could be materially different from those estimates as the effect of future events cannot be determined with certainty. Revisions to estimates are recognized prospectively. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, and expenses are discussed below.

Reserves

The Company uses estimates of oil, natural gas and natural gas liquids ("NGL") reserves in the calculation of depletion, evaluating the recoverability of deferred income tax assets and in the determination of recoverable value estimates for non-financial assets. The process to estimate reserves is complex and requires significant judgment. Estimates of the Company's reserves are evaluated annually by independent qualified reserves evaluators and represent the estimated recoverable quantities of oil, natural gas and NGL reserves and the related cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook.

Estimates of economically recoverable oil, natural gas and NGL reserves and the related cash flows are based on a number of factors and assumptions. Changes to estimates and assumptions such as forecasted commodity prices, production volumes, capital and operating costs and royalty obligations could have a significant impact on reported reserves. Other estimates include ultimate reserve recovery, marketability of oil and natural gas and other geological, economic and technical factors. Changes in the Company's reserves estimates can have a significant impact on the calculation of depletion, the recoverability of deferred income tax assets and in the determination of recoverable value estimates for non-financial assets.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the assets acquired meet the definition of a business in accordance with IFRS. The determination of the fair value assigned to assets acquired and liabilities assumed requires management to make assumptions and estimates. These assumptions or estimates used in determining the fair value of assets acquired and liabilities assumed could impact the amounts assigned to assets, liabilities and goodwill. The determination of the acquisition-date fair value measurement of oil and gas properties acquired represents the largest fair value estimate which is derived from the present value of expected cash flows associated with estimated acquired proved and probable oil and gas reserves prepared by an independent qualified reserve evaluator using assumptions as outlined under "reserves", on an after-tax basis and applying a discount rate. Assumptions used to arrive at the fair value of oil and gas properties are further verified by way of market comparisons and third party sources.

Cash-generating Units

The Company's oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The aggregation of assets in CGUs requires management judgment and is based on geographical proximity, shared infrastructure and similar exposure to market risk.

Identification of Impairment and Impairment Reversal Indicators

Judgment is required to assess when indicators of impairment or impairment reversal exist and when a calculation of the recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication of impairment or impairment reversal. These indicators can be internal such as changes in estimated proved and probable oil and gas reserves ("CGU reserves") and internally estimated oil and gas resources, or external such as market conditions impacting discount rates or market capitalization. The assessment for each CGU considers significant changes in the forecasted cash flows including reservoir performance, the number of development locations and timing of development, forecasted commodity prices, production volumes, capital and operating costs and royalty obligations.

Measurement of Recoverable Amounts

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including cash flows associated with proved and probable oil and gas reserves and the discount rate used to present value future cash flows. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets.

Asset Retirement Obligations

The Company's provision for asset retirement obligations is based on estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future, and risk-free discount rates and inflation rates. The Company uses risk-free discount rates. The provision for asset retirement obligations represents management's best estimate of the present value of the future abandonment and reclamation costs required under current regulatory requirements.

Income Taxes

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in future periods, which requires management judgment. Deferred tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods, which requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes.

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			Years Ended December 31	
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023	**2024**	2023
Petroleum and natural gas sales	**$ 1,017,017**	$ 1,074,623	$ 1,065,515	**$ 4,208,955**	$ 3,382,621
Light oil and condensate [1]	**(573,708)**	(647,587)	(675,072)	**(2,485,060)**	(2,029,123)
NGL [1]	**(56,764)**	(50,101)	(57,027)	**(202,306)**	(145,997)
Natural gas sales [1]	**(34,266)**	(26,076)	(43,674)	**(118,567)**	(125,952)
Heavy oil sales	**$ 352,279**	$ 350,859	$ 289,742	**$ 1,403,022**	$ 1,081,549
Blending and other expense - heavy oil [2]	**(80,148)**	(51,902)	(62,296)	**(263,943)**	(224,802)
Heavy oil, net of blending and other expense	**$ 272,131**	$ 298,957	$ 227,446	**$ 1,139,079**	$ 856,747

(1) Component of petroleum and natural gas sales; see Note 14 Petroleum and Natural Gas Sales in the Consolidated Financial Statements for the year ended December 31, 2024 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			Years Ended December 31	
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023	**2024**	2023
Petroleum and natural gas sales	**$ 1,017,017**	$ 1,074,623	$ 1,065,515	**$ 4,208,955**	$ 3,382,621
Blending and other expense	**(80,148)**	(51,902)	(62,296)	**(263,943)**	(224,802)
Total sales, net of blending and other expense	**$ 936,869**	$ 1,022,721	$ 1,003,219	**$ 3,945,012**	$ 3,157,819
Royalties	**(206,675)**	(223,800)	(228,570)	**(880,086)**	(669,792)
Operating expense	**(145,690)**	(167,119)	(164,873)	**(653,949)**	(570,839)
Transportation expense	**(33,110)**	(36,883)	(29,744)	**(133,142)**	(89,306)
Operating netback	**$ 551,394**	$ 594,919	$ 580,032	**$ 2,277,835**	$ 1,827,882
Realized financial derivatives gain (loss) [1]	**(2,115)**	331	12,377	**1,447**	36,212
Operating netback after realized financial derivatives	**$ 549,279**	$ 595,250	$ 592,409	**$ 2,279,282**	$ 1,864,094

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss; see Note 18 Financial Instruments and Risk Management in the consolidated financial statements for the 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 exploration and evaluation assets, additions to oil and gas properties, payments on lease obligations, transaction costs, and cash premiums on derivatives.

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

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023	**2024**	2023
Cash flow from operating activities	**$ 468,865**	$ 550,042	$ 474,452	**$ 1,908,264**	$ 1,295,731
Change in non-cash working capital	**(13,428)**	(20,813)	14,971	**17,922**	220,895
Transaction costs	**—**	—	5,079	**1,539**	49,045
Additions to exploration and evaluation assets	**—**	—	1,271	**—**	—
Additions to oil and gas properties	**(198,177)**	(306,332)	(200,537)	**(1,256,633)**	(1,012,787)
Payments on lease obligations	**(2,422)**	(2,738)	(4,451)	**(15,510)**	(11,527)
Cash premiums on derivatives	**—**	—	—	**—**	2,263
Free cash flow	**$ 254,838**	$ 220,159	$ 290,785	**$ 655,582**	$ 543,620

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)	**December 31, 2024**	September 30, 2024	December 31, 2023
Credit Facilities	**$ 324,346**	$ 449,116	$ 848,749
Unamortized debt issuance costs - Credit Facilities (1)	**16,861**	16,992	15,987
Long-term notes	**1,932,890**	1,810,701	1,562,361
Unamortized debt issuance costs - Long-term notes (1)	**47,729**	46,168	35,114
Trade payables	**512,473**	584,696	477,295
Share-based compensation liability	**24,732**	23,962	35,732
Dividends payable	**17,598**	17,732	18,381
Other long-term liabilities	**20,887**	19,582	19,147
Cash	**(16,610)**	(21,311)	(55,815)
Trade receivables	**(387,266)**	(375,942)	(339,405)
Prepaids and other assets	**(76,468)**	(78,427)	(83,259)
Net debt	**$ 2,417,172**	$ 2,493,269	$ 2,534,287

(1) Unamortized debt issuance costs were obtained from Note 8 Credit Facilities and Note 9 Long-term Notes from the Consolidated Financial Statements for the year ended December 31, 2024. 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, transaction costs and cash premiums on derivatives.

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

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2024**	September 30, 2024	December 31, 2023	**2024**	2023
Cash flows from operating activities	**$ 468,865**	$ 550,042	$ 474,452	**$ 1,908,264**	$ 1,295,731
Change in non-cash working capital	**(13,428)**	(20,813)	14,971	**17,922**	220,895
Asset retirement obligations settled	**6,449**	8,718	7,646	**28,793**	26,416
Transaction costs	**—**	—	5,079	**1,539**	49,045
Cash premiums on derivatives	**—**	—	—	**—**	2,263
Adjusted funds flow	**$ 461,886**	$ 537,947	$ 502,148	**$ 1,956,518**	$ 1,594,350

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2024, an evaluation was conducted to determine the effectiveness of our “disclosure controls and procedures” (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”) and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")) under the supervision of and with the participation of management, including the President and Chief Executive Officer and the Chief Financial Officer of Baytex (collectively the "certifying officers"). Based on that evaluation, the certifying officers concluded that our disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that we file or submit under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to our management, including the certifying officers, to allow timely decisions regarding the required disclosure.

It should be noted that while the certifying officers believe that our disclosure control and procedures provide a reasonable level of assurance that they are effective, they do not expect that our disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control system are met.

Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Internal control over our financial reporting is a process designed under the supervision of and with the participation of management, including the certifying officers, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

Management has assessed the effectiveness of our "internal control over financial reporting" as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act and as defined by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that our internal control over financial reporting was effective as of December 31, 2024.

The effectiveness of our internal control over financial reporting as of December 31, 2024 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their Report of Independent Registered Public Accounting Firm.

Changes in Internal Control over Financial Reporting

No changes were made to our internal control over financial reporting during the year ended December 31, 2024 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting except for the matters described below.

Baytex previously excluded business processes acquired through the Merger with Ranger on June 20, 2023, from the Company's evaluation of internal control over financial reporting as permitted by applicable securities laws in Canada and the U.S. We completed the evaluation and integration of internal controls over financial reporting of Ranger during the second quarter of 2024.

SELECTED ANNUAL INFORMATION

The following table summarizes key annual financial and operating information over the three most recently completed financial years.

($ thousands, except per common share amounts)	**2024**	2023	2022
Revenues, net of royalties	**3,328,869**	2,712,829	2,326,081
Adjusted funds flow (1)	**1,956,518**	1,594,350	1,165,151
Per common share - basic	**2.44**	2.26	2.09
Per common share - diluted	**2.42**	2.26	2.07
Net (loss) income	**236,597**	(233,356)	855,605
Per common share - basic	**0.29**	(0.33)	1.53
Per common share - diluted	**0.29**	(0.33)	1.52
Dividends declared	**71,985**	37,519	—
Per common share – basic	**0.090**	0.045	—
Total assets	**7,759,745**	7,460,931	5,103,769
Credit facilities - principal	**341,207**	864,736	385,394
Long-term notes - principal	**1,980,619**	1,597,475	554,597
Total sales, net of blending and other expense ($/boe) (2)	**70.43**	70.82	88.56
Total production (boe/d)	**153,048**	122,154	83,519

(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.

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: that we can effectively allocate capital across our assets; 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; that we intend to settle outstanding share based compensation awards in cash; 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; that we may issue or repurchase debt or equity securities from time to time; our expectation that net debt will decline in 2025; our intent to fund certain financial obligations with cash flow from operations and the expected timing of the 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, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2025 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.

RISK FACTORS

We are focused on long-term strategic planning and have identified key risks, uncertainties and opportunities associated with our business that can impact the financial and operational results. Listed below is a description of these risks and uncertainties.

Risks Relating to Our Business and Operations

Crude oil and natural gas prices are volatile. An extended period of low oil and natural gas prices could have a material adverse effect on the Company's business, results of operations, or cash flows and financial condition

Our financial condition is substantially dependent on, and highly sensitive to, the prevailing prices of crude oil and natural gas. Low prices for crude oil and natural gas produced by us could have a material adverse effect on our operations, financial condition and the value and amount of our reserves.

Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of OPEC, OPEC+, the condition of the Canadian, United States, European and Asian economies, the impacts of geopolitical events, including the Russian Ukrainian war and conflicts and hostilities in the Middle East, the imposition of tariffs or other adverse economic or political development in the United States, Europe, the Middle East, Africa, South America or Asia, the impact of pandemics/epidemics, government regulation, the supply of crude oil in North America and internationally, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Additionally, the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. Natural gas prices realized by us are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy and developments related to the market for liquefied natural gas.

In particular, tariffs or other restrictive measures or countermeasures affecting trade between Canada and the United States and between the United States and other countries, if implemented for any period of time, could have a significant impact on the market for oil and natural gas products, especially with respect to oil and gas produced in Canada, and could result in, among other things, price volatility, an increase to the cost of materials used in oil and gas operations, a relative weakening of the Canadian dollar, widening differentials, and decreased demand due to lower economic activity. For more information with respect to tariffs, see *"Industry Conditions - Tariffs"* in the AIF for the year ended December 31, 2024.

All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/ medium crude oil and heavy crude oil (in particular the light/heavy differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, storage capacity, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control. In addition, there is not sufficient pipeline capacity for Canadian crude oil to access the American refinery complex or tidewater to access world markets and the availability of additional transport capacity via rail is more expensive and variable, therefore, the price for Canadian crude oil is very sensitive to pipeline and refinery outages, which contributes to this volatility.

There is a also a risk that refining capacity in the U.S. Gulf Coast may be insufficient to refine all of the light sweet crude oil being produced in the U.S. If light sweet crude oil production remains at current levels or continues to increase, demand for the light crude oil production from our U.S. operations could result in widening price discounts to the world crude prices.

Decreases to or prolonged periods of low commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due. It could also result in the shut-in of currently producing wells without an equivalent decrease in expenses due to fixed costs, a delay or cancellation of existing or future drilling, development or construction programs, un-utilized long-term transportation commitments and a reduction in the value and amount of our reserves.

We conduct assessments of the carrying value of our assets in accordance with IFRS. If crude oil and natural gas forecast prices change, the carrying value of our assets could be subject to revision and our net earnings could be adversely affected.

Our success is highly dependent on our ability to develop existing properties and add to our oil and natural gas reserves

Our oil and natural gas reserves are a depleting resource and decline as such reserves are produced. As a result, our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but also from wells that are productive but do not produce sufficient hydrocarbons to return a profit. Completion of a well does not assure a profit on the investment. Drilling hazards or environmental liabilities or damages and various field operating conditions could greatly increase the cost of operations and adversely affect the production from successful wells. Field operating conditions include, but are not limited to, delays or failure in obtaining governmental, landowner or other stakeholder approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow from operating activities to varying degrees.

There is no assurance we will be successful in developing our reserves or acquiring additional reserves at acceptable costs. Without these reserves additions, our reserves will deplete and as a consequence production from and the average reserve life of our properties will decline, which may adversely affect our business, financial condition, results of operations and prospects.

The anticipated benefits of acquisitions may not be achieved and the Company may dispose of non-core assets for less than their carrying value on the financial statements

Acquisition of oil and gas properties is a key element of maintaining and growing reserves and production and the success of any acquisition will depend on several factors and involves potential risks and uncertainties. Competition for these assets has been and will continue to be intense. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition or do so on commercially acceptable terms. Achieving the benefits of acquisitions depends on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner and the Company's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Company. The integration of acquired businesses and assets may require substantial management effort, time and resources diverting management's focus from other strategic opportunities and operational matters. Additionally, significant acquisitions can change the nature of our operations and business if acquired properties have substantially different operating and geological characteristics or are in different geographic locations than our existing properties. To the extent that acquired properties are substantially different than our existing properties, our ability to efficiently realize the expected economic benefits of such transactions may be limited.

Even though we assess and review the properties we seek to acquire in a manner consistent with what we believe to be industry practice, such reviews are limited in scope, inexact and not capable of identifying all existing or potentially adverse conditions. As a result, the anticipated and desired benefits of an acquisition may not materialize, and may have a material and adverse effect on our business, financial performance and results of operations.

Management continually assesses the value and contribution of its Company's assets. In this regard, non-core assets may be periodically disposed of so that the Company can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Company, if disposed of, may realize less on disposition than their carrying value on the financial statements of the Company.

Availability and cost of capital or borrowing to maintain and/or fund future development and acquisitions

The business of exploring for, developing or acquiring reserves is capital intensive. If external sources of capital (including, but not limited to, debt and equity financing) become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital on acceptable terms and conditions. If external sources of capital become limited or unavailable, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired.

Our ability to obtain additional capital is dependent on, among other things, a general interest in energy industry investments and, in particular, interest in our securities along with our ability to maintain our credit ratings. If we are unable to maintain our indebtedness and financial ratios at levels acceptable to our credit rating agencies, or should our business prospects deteriorate, our credit ratings could be downgraded. Additionally, from time to time, our securities may not meet the investment criteria or characteristics of a particular institutional or other investor, including institutional investors who are not willing or able to hold securities of oil and gas companies for reasons unrelated to financial or operational performance. This may include changes to market-based factors or investor strategies, including ESG, or responsible investing criteria/rankings (for example, ESG, social impact or environmental scores), the implementation of new financial market regulations and fossil fuel divestment initiatives undertaken by governments, pension funds and/or other institutional investors. These events would adversely affect the value of our outstanding securities and existing debt and our ability to obtain new financing, and may increase our borrowing costs.

In addition, companies in the oil and gas sector may be exposed to increasing reputational risks and, in turn, certain financial risks. Specifically, certain financial institutions, in response to concerns related to climate change and the requests and other influences of environmental groups and similar stakeholders, have elected to shift some or all of their investments and financing away from oil and gas related sectors. Additional financial institutions and other investors may elect to do likewise in the future or may impose more stringent conditions with respect to investments in, and financing of, oil and gas-related sectors. As a result, fewer financial institutions and other investors may be willing to invest in, and provide capital, to companies in the oil and gas sector.

From time to time, we may enter into transactions which may be financed in whole or in part with debt or equity. The level of our indebtedness, from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise. Additionally, from time to time, we may issue securities from treasury in order to reduce debt, complete acquisitions and/or optimize our capital structure.

Restrictions and/or costs associated with regulatory initiatives to combat climate change and the physical risks of climate change may have a material adverse affect on our business

Regulatory and Policy Initiatives

Our exploration and production facilities and other operational activities emit GHGs. As such, GHG emissions regulation (including carbon taxes) enacted in jurisdictions where we operate will impact us. In addition, certain of our assets have a higher GHG emissions intensity than others and may be disproportionately impacted.

Negative consequences which could result from new GHG emissions regulation include, but are not limited to: increased operating costs, additional taxes, increased construction and development costs, additional monitoring and compliance costs, a requirement to redesign or retrofit current facilities, permitting delays, additional costs associated with the purchase of emission credits or allowances, the availability to use necessary third-party services and facilities that we rely on, and reduced demand for crude oil. Additionally, if GHG emissions regulation differs by region or type of production, all or part of our production could be subject to costs which are disproportionately higher than those of other producers.

The direct or indirect costs of compliance with GHG emissions regulation may have a material adverse affect on our business, financial condition, results of operations and prospects. At this time, it is not possible to predict whether compliance costs will have a material adverse affect on our financial condition, results of operations or prospects.

Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated obligations, there can be no assurance that we will be able to satisfy our actual future obligations associated with GHG emissions from such funds. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions - Climate Change Regulation*" in the AIF for the year ended December 31, 2024.

Physical Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rain fall, hurricanes, drought and wildfires may restrict our ability to access our properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain assets are located where they are exposed to forest fires, floods, heavy rains, hurricanes, drought and other extreme weather conditions which can lead to significant downtime, damage to such assets and/or increased costs of construction and maintenance. Moreover, extreme weather conditions may lead to disruptions in our ability to transport produced oil and natural gas as well as goods and services in our supply chain.

An energy transition that lessens demand for petroleum products may have an adverse affect on our business

A transition away from the use of petroleum products, which may include conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy, could reduce demand for oil and natural gas. Certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar effect on the demand for oil and gas products. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business and financial condition by decreasing its cash flow from operating activities and the value of its assets.

The amount of oil and natural gas that we can produce and sell is subject to the availability and cost of gathering, processing and pipeline systems

We deliver our products through gathering, processing and pipeline systems to which we do not own and purchasers of our products rely on third party infrastructure to deliver our products to market. The lack of access to capacity in any of the gathering, processing and pipeline systems could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Alternately, a substantial decrease in the use of such systems can increase the cost we incur to use them. In addition, many of the pipeline systems that we use are controlled by a single company and rates are set through a regulatory process, as a result we are subject to the outcome of those regulatory processes. Any significant change in market factors, regulatory decisions or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition.

Our operations in the United States are concentrated in the Eagle Ford shale of South Texas and as a result are highly exposed to the gulf coast refining complex and events which negatively impact the functioning of infrastructure in that area, including as a result of weather conditions, terrorism, local market changes, government regulation and taxation, including limits on the U.S.' ability to export crude oil, could harm our business and, in turn, our financial condition.

Access to the pipeline capacity for the export of crude oil from Canada has, at times, been inadequate for the amount of Canadian production being exported. This has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price and the Brent price for crude oil. In addition, the pro-rationing of capacity on inter-provincial pipeline systems continues to affect the ability to export oil and natural gas from Canada. There can be no certainty that current investment in pipelines will provide sufficient long-term take-away capacity or that currently operating systems will remain in service. There is also no certainty that short-term operational constraints on pipeline systems, arising from pipeline interruption and/or increased supply of crude oil, will not occur.

There is no certainty that crude-by-rail transportation and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on pipeline systems. In addition, our crude-by-rail shipments may be impacted by service delays, inclement weather, derailment or blockades and could adversely impact our crude oil sales volumes or the price received for our product. Crude oil produced and sold by us may be involved in a derailment or incident that results in legal liability or reputational harm.

A portion of our production may be processed through facilities controlled by third parties. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale.

Failure to retain or replace our leadership and key personnel may have an adverse affect on our business

Our success is dependent upon our management, our leadership capabilities and the quality and competency of our talent. Contributions of the existing management team to the immediate and near-term operations of the Company are likely to be of central importance. In addition, certain of the Company's current employees may have significant institutional knowledge that must be transferred to other employees prior to their departure from the workforce. If we are unable to retain key personnel and critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have a material adverse effect on our financial condition, results of operations and prospects.

Income tax laws or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders

Income tax laws and government incentive programs relating to the oil and gas industry may change in a manner that adversely affects our financial condition, results of operations and prospects.

In addition, tax authorities having jurisdiction over us or our Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of our Shareholders. We file all required income tax returns and believe that we are in full compliance with the applicable tax legislation. However, such returns are subject to audit and reassessment by the applicable taxation authority. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries. For further details, see *"Legal Proceedings and Regulatory Actions"* in the AIF for the year ended December 31, 2024. Any such reassessment may have an impact on current and future taxes payable. We believe appropriate provisions for current and deferred income taxes have been made in our consolidated financial statements; however, it is difficult to predict the outcome of audit findings by tax authorities. These findings may increase the amount of our tax liabilities and adversely affect our business, financial condition and results of operations.

We may participate in larger projects and may have more concentrated risk in certain areas of our operations

We have a variety of exploration, development and construction projects underway at any given time. Project delays may result in delayed revenue receipts and cost overruns may result in projects being uneconomic. Our ability to complete projects is dependent on general business, community relationships and market conditions as well as other factors beyond our control, including the availability of skilled labour and manpower, the availability and proximity of pipeline capacity and rail terminals, weather, environmental and regulatory matters, ability to access lands, availability of drilling and other equipment and supplies, and availability of processing capacity.

We could experience adverse impacts associated with a high concentration of activity and tighter drilling spacing

We are subject to drilling, completion and operating risks, including our ability to efficiently execute large-scale project development, as we could experience delays, curtailments and other adverse impacts associated with a high concentration of activity and tighter drilling spacing. A higher concentration of activity and tighter drilling spacing may increase the frequency of operational shut-ins and unintentional communication with other adjacent wells and reduce the total recoverable reserves from the reservoir.

Our financial performance is significantly affected by the cost of developing and operating our assets

Our development and operating costs are affected by a number of factors including, but not limited to: price inflation, increased costs due to tariffs, access to skilled and unskilled labour, availability of equipment, scheduling delays, trucking and fuel costs, failure to maintain quality construction standards, the cost of new technologies and supply chain disruptions. Labour costs, natural gas, electricity, water, diluent and chemicals are examples of some of the operating and other costs that are susceptible to significant fluctuation. Increases to development and operating costs could have a material adverse effect on our financial condition, results of operations or prospects.

Current or future controls, legislation or regulations applicable to the oil and gas industry could adversely affect us

Operations

The oil and gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, completion operations, including the use of hydraulic fracturing, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government. All such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse. The exercise of discretion by governmental authorities under existing controls, legislation or regulations, the implementation of new controls, legislation or regulations or the modification of existing controls, legislation or regulations affecting the oil and gas industry could reduce demand for crude oil and natural gas, increase our costs, or delay or restrict our operations, all of which would have a material adverse effect on our financial condition, results of operations or prospects. See "*Industry Conditions*" in the AIF for the year ended December 31, 2024.

Environment

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, state, provincial and local laws and regulations. Environmental legislation provides for, among other things, the initiation and approval of new oil and natural gas projects, and restrictions and prohibitions on the spill, release or emission of various substances produced in association with oil and natural gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. New environmental legislation at the federal, state, and provincial levels may increase uncertainty among oil and natural gas industry participants as the new laws are implemented, and the effects of the new rules and standards are felt in the oil and natural gas industry. See "*Industry Conditions*" in the AIF for the year ended December 31, 2024.

Compliance with environmental legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liabilities and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge. Although the Company believes that it is in material compliance with current applicable environmental legislation, no assurance can be given that environmental compliance requirements will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Company's business, financial condition, results of operations and prospects.

The Company may have to pay certain costs associated with abandonment and reclamation

The Company will need to comply with the terms and conditions of environmental and regulatory approvals and all legislation regarding the abandonment of its projects and reclamation of the project lands at the end of their economic life, which may result in substantial abandonment and reclamation costs. Any failure to comply with the terms and conditions of the Company's approvals and legislation may result in the imposition of fines and penalties, which may be material. Generally, abandonment and reclamation costs are substantial. The Company records a provision for abandonment and reclamation costs in its financial statements, this provision requires significant judgement and reflects the Company's best estimate of the costs to complete the required abandonment and reclamation work. Actual results may be significantly different than the estimated amounts.

Foreign Investment and Competition Act Legislation

In addition to regulatory requirements mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada) and the *Hart-Scott-Rodino Antitrust Improvements Act* in the United States.

Water use restrictions and/or limited access to water or other fluids may impact the Company's ability to fracture its wells or carry out waterflood operations

The Company undertakes or intends to undertake certain hydraulic fracturing, SAGD, CSS and waterflooding programs. To undertake such operations the Company needs to have access to sufficient volumes of water, or other liquids. There is no certainty that the Company will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as hydraulic fracturing, SAGD, CSS and waterflooding. If the Company is unable to access such water it may not be able to undertake hydraulic fracturing, SAGD, CSS or waterflooding activities, which may reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves.

Public perception and its influence on the regulatory regime

Concern over the impact of oil and gas development on the environment and climate change has received considerable attention in the media and recent public commentary, and the social value proposition of resource development is being challenged. Additionally, certain pipeline leaks, rail car derailments, major weather events and induced seismicity events have gained media, environmental and other stakeholder attention. Future laws and regulation may be impacted by such incidents, which could have a material adverse effect on our financial condition, results of operations or prospects.

New regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Hydraulic fracturing has featured prominently in recent political, media and activist commentary on the subject of water usage, induced seismicity events and environmental damage. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Company's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing, or could effectively prevent the development of crude oil and natural gas. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Regulations regarding the disposal of fluids used in the Company's operations may increase its costs of compliance or subject it to regulatory penalties or litigation

The safe disposal of hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal, provincial and state governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Company's costs of compliance.

Our hedging activities may negatively impact our income and our financial condition

In response to fluctuations in commodity prices, foreign exchange and interest rates, we may utilize various derivative financial instruments and physical sales contracts to manage our exposure under a hedging program. The terms of these arrangements may limit the benefit to us of favourable changes in these factors, including receiving less than the market price for our production, and for certain assets will result in us paying royalties at a reference price which is higher than the hedged price. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil or natural gas to fulfill our delivery obligations. There is also increased exposure to counterparty credit risk. To the extent that our current hedging agreements are beneficial to us, these benefits will only be realized for the period and for the commodity quantities in those contracts. In addition, there is no certainty that we will be able to obtain additional hedges at prices that have an equivalent benefit to us, which may adversely impact our revenues in future periods. For more information about our commodity hedging program, see *"General Description of our Business - Marketing Arrangements and Forward Contracts"* in the AIF for the year ended December 31, 2024.

Variations in interest rates and foreign exchange rates could adversely affect our financial condition

There is a risk that interest rates will increase. An increase in interest rates could result in a significant increase in the amount we pay to service debt and could have an adverse effect on our financial condition, results of operations and prospects.

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canada/U.S. foreign exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our revenues. A substantial portion of our operations and production are in the United States and, as such, we are exposed to foreign currency risk on both revenues and costs to the extent the value of the Canadian dollar decreases relative to the U.S. dollar. In addition, we are exposed to foreign currency risk as a large portion of our indebtedness is denominated in U.S. dollars and the interest payable thereon is payable in U.S. dollars. Future Canada/U.S. foreign exchange rates could also impact the future value of our reserves as determined by our independent evaluator.

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies acquiring Canadian oil and gas properties and may make it more difficult for us to replace reserves through acquisitions.

There are numerous uncertainties inherent in estimating quantities of recoverable oil and natural gas reserves, including many factors beyond our control

The reserves estimates are estimates only. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable oil and natural gas reserves and the future net revenues therefrom are based upon a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies, historical production from the properties, initial production rates, production decline rates, the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities and estimates of future commodity prices and capital costs, all of which may vary considerably from actual results.

All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our reserves as at December 31, 2024 are estimated using forecast prices and costs as set forth under *"Statement of Reserves Data - Pricing Assumptions*" in the AIF for the year ended December 31, 2024. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the estimated price assumptions, the present value of estimated future net revenues for our reserves and net asset value would be reduced and the reduction could be significant. Our actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to our reserves will likely vary from such estimates, and such variances could be material.

Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Reserve reports based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves and such variances could be material.

Acquiring, developing and exploring for oil and natural gas involves many physical hazards. We have not insured and cannot fully insure against all risks related to our operations

Our crude oil and natural gas operations are subject to all of the risks normally incidental to the: (i) storing, transporting, processing, refining and marketing of crude oil, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; including horizontal multi-well pad developments; and (iii) operation and development of crude oil and natural gas properties, including, but not limited to: encountering unexpected formations or pressures, premature declines of reservoir pressure or productivity, blowouts, fires, explosions, equipment failures and other accidents, gaseous leaks, uncontrollable or unauthorized flows of crude oil, natural gas or well fluids, migration of harmful substances, oil spills, corrosion, adverse weather conditions, pollution, acts of vandalism, theft and terrorism and other adverse risks to the environment.

If any of the foregoing risks were to materialize, we could sustain material losses as a result of injury or loss of life, damage to, or destruction of, property, natural resources or equipment, including the costs of repair or replacement, pollution or other environmental harm, interruptions to our ongoing operations, including the reduction or shutting-in of existing production, regulatory investigations and administrative, civil and criminal penalties, and limitation or suspension of current or future operations.

Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable and in certain circumstances we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect on our business, financial condition, results of operations and prospects.

We are not the operator of a significant portion of our drilling locations in the Eagle Ford and, therefore, we will not be able to control the timing of development, associated costs or the rate of production of that acreage

ConocoPhillips is the operator of a significant portion of our Eagle Ford acreage which is located in the Karnes and Atascosa counties and we are reliant upon ConocoPhillips to operate successfully. ConocoPhillips will make decisions based on its own best interest and the collective best interest of all of the working interest owners of this acreage, which may not be in our best interest. We have a limited ability to exercise influence over the operational decisions of ConocoPhillips, including the setting of capital expenditure budgets and determination of drilling locations and schedules. The success and timing of development activities, operated by ConocoPhillips, will depend on a number of factors that will largely be outside of our control, including the timing and amount of capital expenditures, ConocoPhillips's expertise and financial resources, approval of other participants in drilling wells, selection of technology, and the rate of production of reserves.

To the extent that the capital expenditure requirements related to our Eagle Ford acreage exceeds our budgeted amounts, it may reduce the amount of capital we have available to invest in our other assets. We have the ability to elect whether or not to participate in well locations proposed by ConocoPhillips on an individual basis. If we elect to not participate in a well location, we forgo any revenue from such well until ConocoPhillips has recouped, from our working interest share of production from such well, 300% to 500% of our working interest share of the cost of such well.

Our thermal heavy oil projects face additional risks compared to conventional oil and gas production

Our thermal heavy oil projects are capital intensive projects which rely on specialized production technologies. Certain current technologies for the recovery of heavy oil, such as CSS and SAGD, are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the reservoir can also affect the timing and levels of production using new technologies. A large increase in recovery costs could cause certain projects that rely on CSS, SAGD or other new technologies to become uneconomic, which could have an adverse effect on our financial condition and our reserves. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

Project economics and our earnings may be reduced if increases in operating costs are incurred. Factors which could affect operating costs include, without limitation: the costs imposed by GHG emissions regulations, labour costs, the cost of catalysts and chemicals, the cost of natural gas and electricity, water handling and availability, power outages, produced sand causing issues of erosion, hot spots and corrosion, reliability of facilities, maintenance costs, the cost to transport sales products and the cost to dispose of certain by-products.

We may be unable to compete successfully with other organizations in the oil and natural gas industry, or obtain required vendor services to compete

The oil and natural gas industry is highly competitive in all of its phases. The Company competes with numerous other entities in the exploration for, and the development, production and marketing of, oil and natural gas, as well as for capital, acquisitions of reserves and/or resources, undeveloped lands, skilled/qualified labour, access to drilling rigs, service rigs and other equipment and materials such as drilling rigs, hydraulic fracturing pumping equipment and related skilled personnel, access to processing facilities, pipeline and refining capacity, as well as many other services, and in many other respects, with a substantial number of other organizations, many of which may have greater technical and financial resources than the Company. As a result, such competition can significantly increase costs and some of the Company's competitors may have greater opportunities and be able to access, services or vendors that the Company is not able to access, thereby limiting its ability to compete.

Our information technology systems are subject to certain risks

We utilize and have become increasingly dependent upon a number of information technology systems for the administration and management of our business and are subject to a variety of information technology and system risks as a part of our normal course operations, including potential breakdown, invasion, virus, cyber-attack, cyber-fraud, security breach, and destruction or interruption of the Company's information technology systems by third parties or insiders. If our ability to access and use these systems is interrupted and cannot be quickly and easily restored then such event could have a material adverse effect on us. Furthermore, although the Company has security measures and controls in place to mitigate these risks, a breach of its security measures and/or a loss of information could occur and result in a loss of material and confidential information and reputation, breach of privacy laws, and/or disruption to business activities. The significance of any such event is difficult to quantify but may in certain circumstances be material and could have a material adverse effect on the Company's business, financial condition and results of operations. In addition, our vendors, suppliers and other businesses partners may separately suffer disruptions as a result of such security breaks which may directly or indirectly affect our business activities.

Adverse results from litigation may have an adverse affect on our business and reputation

In the normal course of our operations, we currently are and from time to time in the future may become involved in, be named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to personal injuries, including resulting from exposure to hazardous substances, property damage, property taxes, land and access rights, and environmental issues, including claims relating to contamination or natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse effect on our financial condition. For further details, see "*Legal Proceedings and Regulatory Actions*" in the AIF for the year ended December 31, 2024.

Our Credit Facilities may not provide sufficient liquidity and a failure to renew our Credit Facilities at maturity could adversely affect our financial condition

Our Credit Facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our Credit Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms, if at all. There can be no assurance that the amount of our Credit Facilities will be adequate for our future financial obligations, including future capital expenditures, or that we will be able to obtain additional funds. In the event we are unable to refinance our debt obligations, it may impact our ability to fund ongoing operations. In the event that the Credit Facilities are not extended prior to maturity, indebtedness under the Credit Facilities will be repayable at that time. There is also a risk that the Credit Facilities will not be renewed for the same amount or on the same terms. See "*Description of Capital Structure*" in the AIF for the year ended December 31, 2024.

Failure to comply with the covenants in the agreements governing our debt, including our obligation to repay the Senior Notes at maturity, could adversely affect our financial condition

We are required to comply with the covenants in our Credit Facilities and the Senior Notes. If we fail to comply with such covenants, are unable to repay or refinance amounts owned at maturity or pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of our assets by our creditors. The proceeds from any sale of our assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards our debt would the remainder, if any, be available for the benefit of our Shareholders.

Expansion into New Activities

Our operations and the expertise of our management are currently focused primarily on oil and natural gas production, exploration and development in the Provinces of Alberta and Saskatchewan and the State of Texas. In the future, we may acquire or move into new industry related activities or new geographical areas and may acquire different energy-related assets. As a result, we may face unexpected risks or, alternatively, our exposure to one or more existing risk factors may be significantly increased, which may in turn result in our future operational and financial conditions being adversely affected.

Indigenous Land and Rights Claims

Opposition by Indigenous groups to the conduct of the Company's operations, development or exploratory activities in any of the jurisdictions in which the Company conducts business may negatively impact it in terms of public perception, diversion of management's time and resources, and legal and other advisory expenses, and could adversely impact the Company's progress and ability to explore and develop properties.

Indigenous peoples have claimed Indigenous rights and title in portions of Western Canada. We are not aware that any claims have been made in respect of our properties and assets. However, if a claim arose and was successful, such claim may have a material adverse effect on our business, financial condition, results of operations and prospects. In addition, the process of addressing such claims, regardless of the outcome, is expensive and time consuming and could result in delays in the construction of infrastructure systems and facilities which could have a material adverse effect on our business and financial results.

We are subject to risk of default by the counterparties to our contracts and our counterparties may deem us to be a default risk

We are subject to the risk that counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. Furthermore, low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure by such counterparties to make payments or perform their operational or other obligations to us may adversely affect our results of operations, cash flow from operating activities and financial position. Conversely, our counterparties may deem us to be at risk of defaulting on our contractual obligations. These counterparties may require that we provide additional credit assurances by prepaying anticipated expenses or posting letters of credit, which would decrease our available liquidity and increase our costs.

Geopolitical risk and conflicts in or around major oil and gas producing nations can significantly impact commodity prices and, therefore the financial condition of the oil and gas industry

Existing or future conflicts in major oil and gas producing nations and the international response may have potential wide-ranging consequences for global market volatility and economic conditions, including affecting crude oil and natural gas prices. Financial and trade sanctions that may be imposed against countries involved in such conflicts may have continued far-reaching effects on the global economy, energy and commodity prices. The short-, medium- and long-term implications of any such conflicts is difficult to predict with any degree of certainty. Depending on the extent, duration, and severity of such conflict(s), it may have the effect of heightening many of the other risks described herein, including, without limitation, risks relating to global market volatility and economic conditions; cybersecurity threats; crude oil and natural gas prices; inflationary pressures, interest rates and costs of capital; change in trade relations and policies, including the potential for tariffs; and supply chains and cost-effective and timely transportation.

The Company could lose its status as a "foreign private issuer" in the United States

The Company is required to assess its "foreign private issuer" ("FPI") status under U.S. securities laws on an annual basis at the end of its second quarter. While the Company currently qualifies as an FPI, it could lose its FPI status in the future. If the Company were to lose its status as an FPI it would be required to fully comply with both U.S. and Canadian securities and accounting requirements applicable to domestic issuers in each country. In addition, if the Company loses its FPI status, it would be required to report as a U.S. domestic issuer and be subject to other U.S. securities laws applicable to U.S. domestic issuers. The regulatory and compliance costs to the Company under U.S. securities laws as a U.S. domestic issuer may be significantly greater than the costs the Company incurs as a foreign private issuer. For example, as a U.S. domestic issuer, the Company would be required to file periodic reports and registration statements with the SEC on U.S. domestic issuer forms, which are more detailed and extensive in certain respects than the forms available to the Company as a foreign private issuer. The Company would also be required to report its oil and gas reserves and production information in accordance with applicable U.S. disclosure requirements. Such conversion and modifications would involve additional costs and may restrict the Company's access to capital markets for a period of time until it has satisfied SEC reporting requirements. In addition, the Company may lose its ability to rely upon exemptions from certain corporate governance requirements on U.S. stock exchanges that are available to FPIs, which could also increase its costs.

Conflicts of interest may arise between the Company and its directors and officers

Circumstances may arise where directors and officers of the Company are directors or officers of other companies involved in the oil and gas industry which are in competition to, or otherwise in conflict with, the interests of the Company. Directors are required to abstain from voting on matters when they are in conflict. Employees, including officers, are not permitted to partake in activities that do not support the best interests of the Company. Where employee conflicts exist, they are to be provided in writing to our Human Resources Department, which discloses all conflicts to Chief Legal Officer. See "*Directors and Officers – Conflicts of Interest*" in the AIF for the year ended December 31, 2024 and the Company's Code of Business Conduct and Ethics at www.baytexenergy.com.

Risks Related to Ownership of our Securities

Changes in market-based factors may adversely affect the trading price of the Common Shares

The market price of our Common Shares is sensitive to a variety of market-based factors including, but not limited to, commodity prices, interest rates, foreign exchange rates, the decision of certain indices to include our Common Shares and the comparability of the Common Shares to other securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

Forward-Looking Information rely upon assumptions which may not prove correct

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Dividends on the Company's Common Shares and Common Share repurchases are variable

The future acquisition by the Company of Common Shares pursuant to a share buyback (including through its NCIB) and the payment of dividends, if any, and the level thereof is uncertain. Any decision to acquire Common Shares pursuant to a share buyback or to pay dividends 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, commodity prices, 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 the Company under applicable corporate law. In the future, there can be no assurance of the number of Common Shares that the Company will acquire pursuant to a share buyback and there can be no assurance that dividends will be paid or, if paid the amount of such dividends.

Certain Risks for United States and other non-resident Shareholders

The ability of investors resident in the United States to enforce civil remedies is limited

We are a corporation incorporated under the laws of the Province of Alberta, Canada, our principal office is located in Calgary, Alberta and a substantial portion of our assets are located outside the United States. Most of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent qualified reserves evaluators), and all or a substantial portion of their assets are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States

We report our production and reserves quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves, whereas the SEC rules require that a 12-month average price, calculated as the unweighted 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, be utilized.

We have included estimates of proved reserves and proved plus probable reserves. Probable reserves have a lower certainty of recovery than proved reserves. 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. The SEC definitions of proved reserves and probable reserves are different than NI 51-101; therefore, proved, probable and proved plus probable reserves disclosed may not be comparable to United States standards.

As a consequence of the foregoing, our reserves estimates and production volumes may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

There is additional taxation applicable to non-residents

Tax legislation in Canada may impose withholding or other taxes on the cash dividends, stock dividends or other property transferred by us to non-resident shareholders. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Evidence of eligibility for a reduced withholding rate must be filed by the non-resident shareholder in prescribed form with their broker (or in the case of registered shareholders, with the transfer agent). In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our President and Chief Executive Officer and our Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2024, our internal control over financial reporting was effective.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2024 has been audited by KPMG LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2024.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with International Financial Reporting Standards (“IFRS”) as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of the Company. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the Independent Registered Public Accounting Firm to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of KPMG LLP and reviews their fees. The Independent Registered Public Accounting Firm has access to the Audit Committee without the presence of management.

/s/ Eric T. Greager

Eric T. Greager
President and Chief Executive Officer
Baytex Energy Corp.

/s/ Chad L. Kalmakoff

Chad L. Kalmakoff
Chief Financial Officer
Baytex Energy Corp.

March 4, 2025

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Baytex Energy Corp.

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of Baytex Energy Corp. and subsidiaries (the "Company") as of December 31, 2024 and 2023, the related consolidated statements of income (loss) and comprehensive income (loss), changes in equity, and cash flows for the years then ended, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2024 and 2023, and the financial performance and its cash flows for the years then ended, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 4, 2025 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment of indicators of impairment or impairment reversal related to the Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGUs

As discussed in notes 2 and 7 to the consolidated financial statements, the Company assesses its oil and gas properties by cash generating unit ("CGU") for indicators of impairment or impairment reversal at the end of each reporting period. These indicators can be internal such as changes in estimated proved and probable oil and gas reserves ("CGU reserves cash flows") and estimated oil and gas resources ("CGU resources cash flows"), or external such as market conditions impacting discount rates or market capitalization. The estimation of CGU reserves cash flows in the reserve report involves the expertise of independent qualified reserve evaluators, who take into consideration assumptions related to forecasted production volumes, royalty obligations, operating and capital costs and commodity prices ("CGU reserve report assumptions"). The estimation of CGU resource cash flows involves the expertise of internal qualified reserve engineers, who take into consideration assumptions related to the total number and forecasted drilling pace of resource development wells and the per well cash flow for analogous wells in the reserve report (collectively, "CGU resource assumptions"). Based on the Company's assessment of internal and external indicators of impairment or impairment reversal, the Company determined that impairment or impairment reversal testing was not required for the Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGUs as of December 31, 2024.

We identified the assessment of indicators of impairment or impairment reversal related to the Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGUs as a critical audit matter. Indicators of impairment or impairment reversal such as changes in estimated CGU reserves cash flows and CGU resources cash flows required the application of auditor judgement. A high degree of auditor judgment was required in evaluating the Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGU reserve report assumptions and the Eagle Ford Operated CGU resource assumptions, which were used in the assessment of indicators of impairment or impairment reversal. Additionally, the evaluation of the Company's discount rates, in the assessment of indicators of impairment or impairment reversal, required the involvement of valuation professionals with specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to:

- the Company's assessment of internal and external indicators of impairment or impairment reversal for the Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGUs
- the Company's estimation of the Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGU reserves cash flows and related CGU reserve report assumptions
- the Company's estimation of the Eagle Ford Operated CGU resources cash flows and related CGU resource assumptions.

We evaluated the Company's assessment of internal and external indicators of impairment or impairment reversal for the Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGUs by considering whether the quantitative and qualitative information in the analysis was consistent with external market and industry data and the estimate of Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGU reserves cash flows and Eagle Ford Operated CGU resources cash flows.

We evaluated the competence, capabilities and objectivity of the independent qualified reserve evaluators engaged by the Company. We evaluated the methodology used by the independent qualified reserves evaluators to estimate Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGU reserves cash flows for compliance with the applicable regulatory standards. We compared the current year actual production volumes, royalty obligations, operating and capital costs to estimates used in the prior year estimate of proved reserves by CGU for each of the Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGUs to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the estimate of the Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGU reserves cash flows by comparing them to those published by other reserve engineering companies. We assessed the forecasted production volumes, royalty obligations, operating and capital cost assumptions used in the current year estimate of Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGU reserves cash flows by comparing them to historical results.

We evaluated the competence, capabilities, and objectivity of the internal qualified reserve engineers. We compared the number of development well net additions in the current year CGU reserve report for the Eagle Ford Operated CGU to the estimate of forecasted resource development well additions in the prior year full field development plan to assess the Company's ability to accurately forecast. We assessed the total number and forecasted drilling pace of resource development wells in the current year full field development plan of the Eagle Ford Operated CGU by comparing to the prior year full field development plan and agreeing changes to the Eagle Ford Operated CGU reserve report. We evaluated the per well cash flow in the CGU resources cash flows of the Eagle Ford Operated CGU by comparing to the per well cash flows in the CGU reserve report for analogous wells.

We involved valuation professionals with specialized skills and knowledge, who assisted in evaluating the Company's determination of discount rates, in the assessment of indicators of impairment or impairment reversal, by comparing the inputs of the discount rate against publicly available market data for comparable assets and assessing the resulting discount rates for the Eagle Ford Operated, Eagle Ford Non-operated, Viking and Lloydminster CGUs.

Impact of estimated oil and gas reserves on depletion expense related to oil and gas properties

As discussed in note 3 to the consolidated financial statements, the Company depletes its oil and gas properties using the unit-of-production method by depletable area. Under such method, capitalized costs are depleted over estimated proved and probable oil and gas reserves by depletable area ("area reserves"). As discussed in note 7 to the consolidated financial statements, the Company recorded depletion expense related to oil and gas properties of $1,372,063 thousand for the year ended December 31, 2024. The estimation of area reserves involves the expertise of independent qualified reserve evaluators who take into consideration assumptions related to forecasted production volumes, royalty obligations, operating and capital costs and commodity prices (collectively "area reserve report assumptions"). The Company engages independent qualified reserve evaluators to estimate area reserves.

We identified the assessment of the impact of estimated area reserves on depletion expense related to oil and gas properties as a critical audit matter. Changes in area reserve report assumptions could have had a significant impact on the calculation of depletion expense of the depletable area. A high degree of auditor judgment was required in evaluating the area reserves, and related area reserve report assumptions, which were used in the calculation of depletion expense.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to:

- the Company's calculation of depletion expense by depletable area
- the Company's determination of area reserve report assumptions and resulting area reserves.

We assessed the calculation of depletion expense for compliance with International Financial Reporting Standards as issued by the International Accounting Standards Board. We evaluated the competence, capabilities and objectivity of the independent qualified reserve evaluators engaged by the Company. We evaluated the methodology used by the independent qualified reserve evaluators to estimate area reserves for compliance with the applicable regulatory standards. We compared the current year actual production volumes, royalty obligations, operating and capital costs to those estimates used in the prior year estimate of proved reserves for a selection of CGUs to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the estimate of area reserves by comparing them to those published by other reserves engineering companies. We assessed the forecasted production volumes, royalty obligations, operating and capital costs assumptions used in the estimate of area reserves for a selection of CGUs by comparing them to historical results.

/s/ KPMG LLP

Chartered Professional Accountants

We have served as the Company's auditor since 2016.

Calgary, Canada
March 4, 2025

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Baytex Energy Corp.

Opinion on Internal Control Over Financial Reporting

We have audited Baytex Energy Corp.'s and subsidiaries' (the "Company") internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2024, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated statements of financial position of the Company as at December 31, 2024 and 2023, the related consolidated statements of income (loss) and comprehensive income (loss), changes in equity, and cash flows for the years then ended, and the related notes (collectively, the consolidated financial statements), and our report dated March 4, 2025 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

Chartered Professional Accountants

Calgary, Canada
March 4, 2025

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

As at	Notes	December 31, 2024	December 31, 2023
ASSETS			
Current assets			
Cash	18	$ **16,610**	$ 55,815
Trade receivables	14, 18	**387,266**	339,405
Prepaids and other assets		**20,178**	21,530
Financial derivatives	18	**25,573**	23,274
		449,627	440,024
Non-current assets			
Exploration and evaluation assets	6	**124,355**	90,919
Oil and gas properties	7	**6,921,168**	6,619,033
Other plant and equipment		**8,025**	7,936
Lease assets		**22,068**	28,145
Prepaids and other assets	15	**56,290**	61,729
Deferred income tax asset	15	**178,212**	213,145
		$ **7,759,745**	$ 7,460,931
LIABILITIES			
Current liabilities			
Trade payables	18	$ **512,473**	$ 477,295
Share-based compensation liability	12	**18,806**	28,508
Dividends payable	11,18	**17,598**	18,381
Lease obligations		**9,193**	13,391
Asset retirement obligations	10	**15,656**	20,448
		573,726	558,023
Non-current liabilities			
Other long-term liabilities		**20,887**	19,147
Share-based compensation liability	12	**5,926**	7,224
Financial derivatives	18	**1,645**	—
Credit facilities	8	**324,346**	848,749
Long-term notes	9	**1,932,890**	1,562,361
Lease obligations		**15,459**	16,056
Asset retirement obligations	10	**625,295**	602,951
Deferred income tax liability	15	**88,561**	21,333
		3,588,735	3,635,844
SHAREHOLDERS' EQUITY			
Shareholders' capital	11	**6,137,479**	6,527,289
Contributed surplus		**361,854**	193,077
Accumulated other comprehensive income		**1,093,261**	690,917
Deficit		**(3,421,584)**	(3,586,196)
		4,171,010	3,825,087
		$ **7,759,745**	$ 7,460,931

Subsequent events (note 11 and note 18) and Commitments (note 20)

See accompanying notes to the consolidated financial statements.

/s/ Jennifer A. Maki	*/s/ Angela S. Lekatsas*
Jennifer A. Maki	Angela S. Lekatsas
Director, Baytex Energy Corp.	Director, Baytex Energy Corp.

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

Years Ended December 31	Notes	**2024**	2023
Revenue, net of royalties			
Petroleum and natural gas sales	14	**$ 4,208,955**	$ 3,382,621
Royalties		**(880,086)**	(669,792)
		3,328,869	2,712,829
Expenses			
Operating		**653,949**	570,839
Transportation		**133,142**	89,306
Blending and other		**263,943**	224,802
General and administrative		**81,746**	69,789
Transaction costs	4	**1,539**	49,045
Exploration and evaluation	6	**779**	8,896
Depletion and depreciation		**1,385,910**	1,047,904
Impairment loss	7	**—**	833,662
Share-based compensation	12	**17,872**	37,699
Financing and interest	16	**268,374**	192,173
Financial derivatives gain	18	**(2,101)**	(24,695)
Foreign exchange loss (gain)	17	**155,895**	(10,848)
Loss on dispositions		**1,220**	141,295
Other income		**(6,689)**	(456)
		2,955,579	3,229,411
Net income (loss) before income taxes		**373,290**	(516,582)
Income tax expense (recovery)	15		
Current income tax expense		**21,766**	14,403
Deferred income tax expense (recovery)		**114,927**	(297,629)
		136,693	(283,226)
Net income (loss)		**$ 236,597**	$ (233,356)
Other comprehensive income (loss)			
Foreign currency translation adjustment		**402,344**	(65,278)
Comprehensive income (loss)		**$ 638,941**	$ (298,634)
Net income (loss) per common share	13		
Basic		**$ 0.29**	$ (0.33)
Diluted		**$ 0.29**	$ (0.33)
Weighted average common shares	13		
Basic		**803,435**	704,896
Diluted		**807,711**	704,896

See accompanying notes to the consolidated financial statements.

Baytex Energy Corp.
Consolidated Statements of Changes in Equity
(thousands of Canadian dollars)

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	Total equity
Balance at December 31, 2022		$ 5,499,664	$ 89,879	$ 756,195	$ (3,315,321)	**$ 3,030,417**
Issued on corporate acquisition	4	1,326,435	21,316	—	—	**1,347,751**
Vesting of share awards	11	26,229	(37,462)	—	—	**(11,233)**
Share-based compensation	12	—	16,237	—	—	**16,237**
Repurchase of common shares for cancellation	11	(325,039)	103,107	—	—	**(221,932)**
Dividends declared	11	—	—	—	(37,519)	**(37,519)**
Comprehensive loss		—	—	(65,278)	(233,356)	**(298,634)**
Balance at December 31, 2023		$ 6,527,289	$ 193,077	$ 690,917	$ (3,586,196)	**$ 3,825,087**
Vesting of share awards	11	1,167	—	—	—	**1,167**
Repurchase of common shares for cancellation	11	(390,977)	168,777	—	—	**(222,200)**
Dividends declared	11	—	—	—	(71,985)	**(71,985)**
Comprehensive income		—	—	402,344	236,597	**638,941**
Balance at December 31, 2024		$ 6,137,479	$ 361,854	$ 1,093,261	$ (3,421,584)	**$ 4,171,010**

See accompanying notes to the consolidated financial statements.

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

Years Ended December 31	Notes	2024	2023
CASH PROVIDED BY (USED IN):			
Operating activities			
Net income (loss)		**$ 236,597**	$ (233,356)
Adjustments for:			
Non-cash share-based compensation	12	**—**	16,237
Unrealized foreign exchange loss (gain)	17	**153,930**	(14,300)
Exploration and evaluation	6	**779**	8,896
Depletion and depreciation		**1,385,910**	1,047,904
Impairment loss	7	**—**	833,662
Non-cash financing and accretion	16	**62,270**	32,350
Non-cash other income	10	**—**	(1,271)
Unrealized financial derivatives (gain) loss	18	**(654)**	11,517
Cash premiums on derivatives		**—**	(2,263)
Loss on dispositions		**1,220**	141,295
Deferred income tax expense (recovery)	15	**114,927**	(297,629)
Asset retirement obligations settled	10	**(28,793)**	(26,416)
Change in non-cash working capital	19	**(17,922)**	(220,895)
Cash flows from operating activities		**1,908,264**	1,295,731
Financing activities			
(Decrease) increase in credit facilities	8	**(539,676)**	477,387
Decrease in acquired credit facilities	4	**—**	(373,608)
Debt issuance costs		**(25,023)**	(40,424)
Payments on lease obligations		**(15,510)**	(11,527)
Net proceeds from issuance of long-term notes	9	**780,936**	1,046,197
Redemption of long-term notes	9	**(580,913)**	—
Redemption of acquired long-term notes	4	**—**	(569,256)
Repurchase of common shares	11	**(222,200)**	(221,932)
Dividends declared	11	**(71,985)**	(37,519)
Change in non-cash working capital	19	**6,200**	(3,068)
Cash flows (used in) from financing activities		**(668,171)**	266,250
Investing activities			
Additions to oil and gas properties	7	**(1,256,633)**	(1,012,787)
Additions to other plant and equipment		**(5,370)**	(4,416)
Corporate acquisition, net of cash acquired	4	**—**	(662,579)
Property acquisitions		**(52,415)**	(38,914)
Proceeds from dispositions		**46,495**	160,256
Change in non-cash working capital	19	**(11,375)**	46,810
Cash flows used in investing activities		**(1,279,298)**	(1,511,630)
Change in cash		**(39,205)**	50,351
Cash, beginning of year		**55,815**	5,464
Cash, end of year		**$ 16,610**	$ 55,815
Supplementary information			
Interest paid		**$ 200,218**	$ 153,224
Income taxes paid		**$ 19,430**	$ 3,603

See accompanying notes to the consolidated 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 consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). The material accounting policies set forth below were consistently applied to all periods presented.

The consolidated financial statements were approved by the Board of Directors of Baytex on March 4, 2025.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of certain fair value measurements noted in the material accounting policies set forth below. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company. References to “US$” are to United States ("U.S.") dollars. All financial information is rounded to the nearest thousand, except per share amounts or where otherwise indicated.

Measurement Uncertainty and Judgments

Management makes judgements 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 government of the United States of America has announced tariffs on goods imported from Canada, including a 10% tariff on Canadian energy imports, effective March 4, 2025. 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.

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information available, including considerations related to various regulatory and legislative requirements, to the Company at the time of financial statement preparation. Actual results could be materially different from those estimates as the effect of future events cannot be determined with certainty. Revisions to estimates are recognized prospectively. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, and expenses are discussed below.

Reserves

The Company uses estimates of oil, natural gas and natural gas liquids ("NGL") reserves in the calculation of depletion, evaluating the recoverability of deferred income tax assets and in the determination of recoverable value estimates for non-financial assets. The process to estimate reserves is complex and requires significant judgment. Estimates of the Company's reserves are evaluated annually by independent qualified reserves evaluators and represent the estimated recoverable quantities of oil, natural gas and NGL reserves and the related cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* and the Canadian Oil and Gas Evaluation Handbook.

Estimates of economically recoverable oil, natural gas and NGL reserves and the related cash flows are based on a number of factors and assumptions. Changes to estimates and assumptions such as forecasted commodity prices, production volumes, capital and operating costs and royalty obligations could have a significant impact on reported reserves. Other estimates include ultimate reserve recovery, marketability of oil and natural gas and other geological, economic and technical factors. Changes in the Company's reserves estimates can have a significant impact on the calculation of depletion, the recoverability of deferred income tax assets and in the determination of recoverable value estimates for non-financial assets.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the assets acquired meet the definition of a business in accordance with IFRS. The determination of the fair value assigned to assets acquired and liabilities assumed requires management to make assumptions and estimates. These assumptions or estimates used in determining the fair value of assets acquired and liabilities assumed could impact the amounts assigned to assets, liabilities and goodwill. The determination of the acquisition-date fair value measurement of oil and gas properties acquired represents the largest fair value estimate which is derived from the present value of expected cash flows associated with estimated acquired proved and probable oil and gas reserves prepared by an independent qualified reserve evaluator using assumptions as outlined under "reserves", on an after-tax basis and applying a discount rate. Assumptions used to arrive at the fair value of oil and gas properties are further verified by way of market comparisons and third party sources.

Cash-generating Units ("CGUs")

The Company's oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash inflows that are largely independent of the cash inflows from other assets or groups of assets. The aggregation of assets in CGUs requires management judgment and is based on geographical proximity, shared infrastructure and similar exposure to market risk.

Identification of Impairment or Impairment Reversal Indicators

Judgment is required to assess when indicators of impairment or impairment reversal exist and when a calculation of the recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication of impairment or impairment reversal. These indicators can be internal such as changes in estimated proved and probable oil and gas reserves ("CGU reserves") and internally estimated oil and gas resources, or external such as market conditions impacting discount rates or market capitalization. The assessment for each CGU considers significant changes in the forecasted cash flows including reservoir performance, the number of development locations and timing of development, forecasted commodity prices, production volumes, capital and operating costs and royalty obligations.

Measurement of Recoverable Amounts

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including cash flows associated with proved and probable oil and gas reserves and the discount rate used to present value future cash flows. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets.

Asset Retirement Obligations

The Company's provision for asset retirement obligations is based on estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future, and risk-free discount rates and inflation rates. The Company uses risk-free discount rates. The provision for asset retirement obligations represents management's best estimate of the present value of the future abandonment and reclamation costs required under current regulatory requirements.

Income Taxes

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the applicable legislative requirements may result in a material change to the Company's provision for income taxes.

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 its first standards which are aligned with the ISSB release and include suggestions for Canadian-specific modifications. The Canadian Securities Administrators have also issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters which sets forth additional reporting requirements for Canadian Public Companies. Baytex continues to monitor developments on these reporting requirements and has not yet quantified the cost to comply with these regulations.

3. MATERIAL ACCOUNTING POLICIES

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly owned subsidiaries. Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies to obtain benefits from its activities. Significant subsidiaries included in the Company's accounts include Baytex Energy USA, Inc., Baytex Energy Ltd. and Baytex Energy Limited Partnership. Intercompany transactions are eliminated in preparation of the consolidated financial statements.

Many of the Company's exploration, development and production activities are conducted through jointly owned assets. The consolidated financial statements include the Company's proportionate share of the assets, liabilities, revenues and expenses generated by jointly owned assets.

Revenue Recognition

Revenue from the sale of light oil and condensate, heavy oil, natural gas liquids, and natural gas is recognized based on the consideration specified in contracts with customers. Baytex recognizes revenue by unit of production and when control of the product transfers to the customer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product and it is physically transferred to the customer at the agreed upon delivery point.

The nature of the Company's performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal. Baytex recognizes revenue on a gross basis when it acts as the principal and has primary responsibility for the transaction. Revenue is recognized on a net basis when Baytex acts in the capacity of an agent rather than as a principal.

The transaction price for variable price contracts is based on a representative commodity price index, and typically includes adjustments for quality, location, delivery method, or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded varies depending on the grade, quality and quantities of oil or natural gas transferred to customers. Market conditions, which impact the Company's ability to negotiate certain components of the transaction price, can also cause the amount of revenue recorded to fluctuate from period to period.

Pipeline tariffs, tolls and fees charged to other entities for the use of pipelines and facilities owned by Baytex are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Pipeline tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Exploration and Evaluation ("E&E") Assets

Once the legal right to explore has been acquired, costs directly associated with an exploration program are capitalized as E&E assets until results of the exploration program have been evaluated. Costs capitalized as E&E assets include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing of initial production results.

E&E expenditures are costs incurred in an area where technical feasibility and commercial viability has not yet been determined. The technical feasibility and commercial viability is dependent on whether extracting petroleum and natural gas resources is demonstrable. If the asset is determined not to be technically feasible or commercially viable the accumulated E&E assets associated with the exploration project are charged to E&E expense in the period the determination is made.

Upon determination of technical feasibility and commercial viability, as evidenced by demonstrating the ability to extract mineral resources and management's intention to develop the E&E asset, the accumulated costs associated with the exploration project are tested for impairment and transferred to oil and gas properties.

Oil and Gas Properties

Oil and gas properties are initially recorded at cost and include the costs to acquire, develop, complete geological and geophysical surveys, drill and complete wells for production, and construct and install infrastructure including wellhead equipment and processing facilities.

Oil and gas properties includes costs related to planned major inspection, overhaul and turnaround activities to maintain items of oil and gas properties and benefit future years of operations. Replacements outside of a major inspection, overhaul or turnaround are recognized as oil and gas properties when it is probable the economic benefits of the replacement will be realized by the Company in the future. The carrying amount of any replaced or disposed item of oil and gas properties is derecognized. Repair and maintenance costs incurred for servicing an item of oil and gas properties is recorded as operating expense as incurred.

Depletion

The costs associated with oil and gas properties are depleted on a unit-of-production basis by depletable area over proved and probable reserves once commercial production has commenced. Forecasted capital costs required to bring proved and probable reserves into production are included in the depletable base. For purposes of the depletion calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil equivalent.

Impairment or Impairment Reversals

Non-financial Assets

The Company reviews its oil and gas properties and E&E assets at a CGU level for indicators of impairment or impairment reversal at the end of each reporting period. E&E assets are also assessed for impairment upon transfer to oil and gas properties. The recoverable amount of the asset is estimated if indicators of impairment or impairment reversal exist.

When reviewing for indicators of impairment or impairment reversal, and testing for impairment or impairment reversal when indicators have been identified, assets are grouped together at a CGU level. The recoverable amount of an asset or CGU is the higher of its FVLCD and its VIU. The determination of recoverable amount includes estimates of proved and probable oil and gas reserves and the associated cash flows. Factors that impact these cash flows include forecasted CGU production volumes, royalty obligations, operating costs, capital costs, commodity prices, taxes, along with inflation and discount rates used to estimate present value. FVLCD is the amount that would be obtained from the sale of an asset or CGU in an arm's length transaction. In determining FVLCD, recent comparable market transactions are considered if available. In the absence of such transactions, an appropriate valuation model is used. VIU is assessed using the present value of the estimated future cash flows of the asset or CGU. The estimated future cash flows are adjusted for risks specific to the asset or CGU and are discounted using a discount rate based on the Company’s weighted average cost of capital adjusted for risks specific to the CGU.

Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. The impairment reduces the carrying amount of the individual assets in the CGU on a pro-rata basis.

Impairments may be reversed for all CGUs and individual assets when there is indication that a previously recognized impairment may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. An impairment may be reversed only to the extent that the CGU’s revised carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and depletion, had no impairment been recognized.

Impairments and impairment reversals are recorded in net income or loss in the period the impairment or impairment reversal occurs.

Asset Retirement Obligations

The Company recognizes asset retirement obligations when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. The Company’s asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities using existing technology and the estimated time period during which these costs will be incurred in the future.

Asset retirement obligations are recognized for future asset retirement costs associated with the abandonment and reclamation of the Company's E&E assets and oil and gas properties. Asset retirement obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, discounted using the risk-free interest rate. The present value of the liability is capitalized as part of the cost of the related asset and depleted over its useful life. The asset retirement obligation is accreted until the date of expected settlement of the retirement obligation and is recognized within financing and interest expense in net income or loss. Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows or the discount rates are recognized as changes in the asset retirement obligation provision and related asset at each reporting date.

Foreign Currency Translation

Foreign Transactions

Transactions completed in currencies other than the functional currency are translated into the functional currency at the exchange rates prevailing at the time of the transactions. Foreign currency assets and liabilities are translated to functional currency at the period-end exchange rate. Revenue and expenses are translated to functional currency using the average exchange rate for the period. Realized and unrealized gains and losses resulting from the settlement or translation of foreign currency transactions are included in net income or loss.

Foreign Operations

The functional currency of the Company's subsidiaries is the currency of the primary economic environment in which the entity operates. The Company's U.S. operations are conducted in USD. Management judgement is required in the designation of a subsidiary's functional currency.

The financial statements of each entity are translated into Canadian dollars during the preparation of the Company's consolidated financial statements. Refer to the *Consolidation* section of Note 3 for a list of the Company's entities. The assets and liabilities of a foreign operation are translated to Canadian dollars at the period-end exchange rate. Revenues and expenses of foreign operations are translated to Canadian dollars using the average exchange rate for the period. Foreign exchange differences are recognized in other comprehensive income or loss.

If the Company or any of its entities disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in net income or loss.

Financial Instruments

Financial assets are initially classified into two categories: measured at amortized cost or fair value through profit or loss ("FVTPL").

The measurement category for each class of financial asset and financial liability is set forth in the following table.

Financial Instrument	Classification
Cash	Amortized cost
Trade receivables	Amortized cost
Financial derivatives	Fair value through profit or loss
Trade payables	Amortized cost
Dividends payable	Amortized cost
Credit facilities	Amortized cost
Long-term notes	Amortized cost

Debt issuance costs related to the amendment of the Company's credit facilities or the issuance of long-term notes are capitalized and amortized as financing costs over the term of the credit facilities or long-term notes. For a financial asset or a financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to, or deducted from, the fair value on initial recognition and amortized through net income or loss over the term of the financial instrument. Transaction costs that are directly attributable to the acquisition or issue of a financial asset or a financial liability classified as FVTPL are expensed at inception of the contract.

The Company formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The Company has not designated its financial derivative contracts as effective accounting hedges, and therefore has not applied hedge accounting. As a result, the Company applies the fair value method of accounting for all derivative instruments. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts. Attributable transaction costs are recognized in net income or loss when incurred.

The Company accounts for its physical delivery sales contracts as executory contracts. These contracts are entered into and held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements. As such, these contracts are not considered to be derivative financial instruments and are not recorded at fair value on the statements of financial position. Settlements on these physical delivery sales contracts are recognized in revenue in the period the product is delivered to the sales point.

Income Taxes

Current and deferred income taxes are recognized in net income or loss, except when they relate to items that are recognized directly in equity, in which case the current and deferred taxes are also recognized directly in equity.

Current income taxes for the current and prior periods are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted at the end of the reporting period. The Company recognizes the financial statement impact of a tax filing position when it is probable that the position will be upheld. The asset or liability is measured based on an assessment of probable outcomes and their associated probabilities.

The Company follows the asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and the corresponding tax basis used in the computation of taxable income. Deferred income tax liabilities are generally recognized for all taxable temporary differences. Deferred income tax assets are recognized for all deductible temporary differences to the extent future recovery is probable. The carrying amount of deferred income tax assets is reviewed at the end of each reporting period and reduced or increased to the extent that it is no longer probable or becomes probable that sufficient taxable income will be available to allow all or part of the asset to be recovered. Deferred income taxes are calculated using enacted or substantively enacted tax rates. Deferred income tax balances are adjusted for any changes in the enacted or substantively enacted tax rates and the adjustment is recognized in the period that the rate change occurs.

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in future periods, which requires management judgment. Deferred tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods, which requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes.

New Accounting Standards Adopted

Effective January 1, 2024, Baytex adopted amendments to IAS 1 *Presentation of Financial Statements* which was issued by the IASB in January 2020. The amendments further clarify the requirements for the presentation of liabilities as current or non-current in the consolidated statements of financial position. These amendments have not had a material impact on our 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.

4. BUSINESS COMBINATION

On June 20, 2023, Baytex closed the acquisition of Ranger Oil Corporation (“Ranger”), a publicly traded oil and gas exploration and production company with operations in the Eagle Ford. Baytex acquired all of the issued and outstanding common shares of Ranger and is treated as the acquirer for accounting purposes. The acquisition increases Baytex's Eagle Ford scale and provides an operating platform to effectively allocate capital across the Western Canadian Sedimentary Basin and the Eagle Ford.

The acquisition was accounted for as a business combination with the net assets and liabilities recorded at fair value at the acquisition date. The total consideration of US$1.6 billion ($2.1 billion) consisted of $732.8 million of cash consideration and 311.4 million Baytex common shares valued at approximately $1.3 billion (based on the closing price of Baytex’s common shares of $4.26 per share on the Toronto Stock Exchange on June 20, 2023). Under the terms of the agreement, Ranger shareholders received 7.49 Baytex shares plus US$13.31 cash for each share of Ranger common stock.

The fair value of oil and gas properties acquired was primarily based on estimated cash flows associated with proved and probable oil and gas reserves acquired and the discount rate. Factors that impact these reserves cash flows include forecasted production volumes, royalty obligations, operating and capital costs, taxes and commodity prices. The estimation of reserves cash flows involves the expertise of the independent qualified reserve evaluators. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets. The fair value of the acquired oil and gas properties were determined using a discount rate of 12.2%.

Asset retirement obligations were determined using internal estimates of the timing and estimated costs associated with the abandonment and reclamation of the wells and facilities acquired using a market rate of interest of 9.0%.

The total consideration paid and estimates of the fair value of the assets and liabilities acquired as at the date of the acquisition are set forth in the table below. The purchase price equation was based on management's best estimate of the assets acquired and liabilities assumed. There were no measurement period adjustments recorded during the year ended December 31, 2024 and the purchase price is considered final.

		USD		CAD [1]
Consideration				
Cash	$	553,150	$	732,840
Common shares issued		1,001,196		1,326,435
Share-based compensation [2]		20,107		26,638
Total consideration	**$**	**1,574,453**	**$**	**2,085,913**
Fair value of net assets acquired				
Oil and gas properties	$	2,337,173	$	3,096,404
Working capital deficiency excluding bank debt and financial derivatives [3]		(120,565)		(159,731)
Financial derivatives		17,030		22,562
Lease assets		15,708		20,811
Lease obligations		(15,708)		(20,811)
Credit facilities		(282,000)		(373,608)
Long-term notes		(429,676)		(569,256)
Asset retirement obligations		(23,632)		(31,310)
Deferred income tax asset		76,123		100,852
Net assets acquired	**$**	**1,574,453**	**$**	**2,085,913**

(1) Exchange rate used to translate the U.S. denominated values above is the rate as at the closing date being CAD/USD 1.32485.

(2) Following closing of the transaction, holders of awards outstanding under Ranger's share based compensation plans are entitled to Baytex common shares rather than Ranger common shares with adjustment to the quantity outstanding based on the exchange ratio for Ranger shares. The fair value of share awards allocated to consideration was based on the service period that had occurred prior to the acquisition date while the remaining fair value of the share awards assumed by Baytex is being recognized over the remaining future service periods (note 12). Included in this balance is $21.3 million (US$16.1 million) of awards that were fully vested at close of the Ranger acquisition and $5.3 million (US$4.0 million) of cash-based awards included in share-based compensation liability.

(3) Includes $70.3 million (US$53.0 million) of cash. Trade receivables acquired is net of a provision for expected credit losses of approximately $0.3 million.

The cash portion of the transaction was funded with Baytex’s expanded credit facility which increased to US$1.1 billion at close of the transaction, US$150 million from a two-year term loan facility, and the net proceeds from the issuance of US$800 million senior unsecured notes due 2030. Baytex closed the US$800 million, senior unsecured note offering on April 27, 2023 and the net proceeds were released from escrow on June 20, 2023.

These consolidated financial statements include the results of operations of Ranger for the period following closing of the transaction on June 20, 2023. For the year ended December 31, 2023, the acquisition contributed revenues and net income before income taxes of $939.4 million and $165.1 million, respectively. Had the acquisition occurred on January 1, 2023, revenues and net income before income taxes would have increased by approximately $1.7 billion and $366.7 million, respectively, for the year ended December 31, 2023. This pro-forma information is not necessarily indicative of the results of operations that would have resulted had the acquisition been reflected on the dates indicated, or that may be obtained in the future.

During the year ended December 31, 2023, Baytex incurred transaction costs of $49.0 million. Transaction costs include consulting, advisory fees, legal fees, tax fees and other professional fees of $41.7 million, as well as post-combination employee-related costs of $7.3 million.

5. 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 U.S.; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Years Ended December 31	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 1,874,046**	$ 1,729,021	**$ 2,334,909**	$ 1,653,600	**$ —**	$ —	**$ 4,208,955**	$ 3,382,621
Royalties	**(261,205)**	(213,148)	**(618,881)**	(456,644)	**—**	—	**(880,086)**	(669,792)
	1,612,841	1,515,873	**1,716,028**	1,196,956	**—**	—	**3,328,869**	2,712,829
Expenses								
Operating	**336,069**	368,605	**317,880**	202,234	**—**	—	**653,949**	570,839
Transportation	**84,211**	64,325	**48,931**	24,981	**—**	—	**133,142**	89,306
Blending and other	**263,943**	224,802	**—**	—	**—**	—	**263,943**	224,802
General and administrative	**—**	—	**—**	—	**81,746**	69,789	**81,746**	69,789
Transaction costs	**—**	—	**—**	—	**1,539**	49,045	**1,539**	49,045
Exploration and evaluation	**779**	8,896	**—**	—	**—**	—	**779**	8,896
Depletion and depreciation	**473,792**	484,232	**898,271**	555,548	**13,847**	8,124	**1,385,910**	1,047,904
Impairment loss	**—**	184,000	**—**	649,662	**—**	—	**—**	833,662
Share-based compensation	**—**	—	**—**	—	**17,872**	37,699	**17,872**	37,699
Financing and interest	**—**	—	**—**	—	**268,374**	192,173	**268,374**	192,173
Financial derivatives gain	**—**	—	**—**	—	**(2,101)**	(24,695)	**(2,101)**	(24,695)
Foreign exchange loss (gain)	**—**	—	**—**	—	**155,895**	(10,848)	**155,895**	(10,848)
(Gain) loss on dispositions	**(4,134)**	141,295	**5,354**	—	**—**	—	**1,220**	141,295
Other (income) expense	—	(1,271)	—	—	**(6,689)**	815	**(6,689)**	(456)
	1,154,660	1,474,884	**1,270,436**	1,432,425	**530,483**	322,102	**2,955,579**	3,229,411
Net income (loss) before income taxes	**458,181**	40,989	**445,592**	(235,469)	**(530,483)**	(322,102)	**373,290**	(516,582)
Income tax expense (recovery)								
Current income tax expense							**21,766**	14,403
Deferred income tax expense (recovery)							**114,927**	(297,629)
							136,693	(283,226)
Net income (loss)	**$ 458,181**	$ 40,989	**$ 445,592**	$ (235,469)	**$ (530,483)**	$ (322,102)	**$ 236,597**	$ (233,356)
Additions to oil and gas properties	**489,486**	463,198	**767,147**	549,589	**—**	—	**1,256,633**	1,012,787
Corporate acquisition, net of cash acquired	**—**	—	**—**	662,579	**—**	—	**—**	662,579
Property acquisitions	**48,889**	20,023	**3,526**	18,891	**—**	—	**52,415**	38,914
Proceeds from dispositions	**(41,149)**	(160,256)	**(5,346)**	—	**—**	—	**(46,495)**	(160,256)

As at	December 31, 2024	December 31, 2023
Canadian assets	**$ 2,381,991**	$ 2,289,083
U.S. assets	**5,322,088**	5,112,493
Corporate assets	**55,666**	59,355
Total consolidated assets	**$ 7,759,745**	$ 7,460,931

6. EXPLORATION AND EVALUATION ASSETS

	December 31, 2024	December 31, 2023
Balance, beginning of year	**$ 90,919**	$ 168,684
Property acquisitions	**39,355**	19,519
Divestitures	**(2,009)**	(2,998)
Exploration and evaluation expense	**(779)**	(8,896)
Transfers to oil and gas properties (note 7)	**(3,131)**	(83,530)
Foreign currency translation	**—**	(1,860)
Balance, end of year	**$ 124,355**	$ 90,919

At December 31, 2023 and December 31, 2024, there were no indicators of impairment or impairment reversal for exploration and evaluation assets in any of the Company's CGUs.

7. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2022	**$ 12,042,216**	**$ (7,421,450)**	**$ 4,620,766**
Capital expenditures	1,012,787	—	1,012,787
Corporate acquisition (note 4)	3,096,404	—	3,096,404
Property acquisitions	24,989	—	24,989
Transfers from exploration and evaluation assets (note 6)	83,530	—	83,530
Transfers from lease assets	7,611	—	7,611
Change in asset retirement obligations (note 10)	54,166	—	54,166
Divestitures	(668,621)	321,407	(347,214)
Impairment loss	—	(833,662)	(833,662)
Foreign currency translation	(127,065)	66,501	(60,564)
Depletion	—	(1,039,780)	(1,039,780)
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 6)	3,131	—	3,131
Transfers from lease assets	8,210	—	8,210
Change in asset retirement obligations (note 10)	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**

At December 31, 2024, there were no indicators of impairment or impairment reversal for oil and gas properties in any of the Company's CGUs.

2023 Impairment

At December 31, 2023, the Company identified indicators of impairment for oil and gas properties in the legacy non-operated Eagle Ford CGU due to changes in reserves and in the Viking CGU due to changes in reserves and a loss recorded on disposition of an asset. The recoverable amounts for the two CGUs were not sufficient to support their carrying values which resulted in an impairment loss of $833.7 million recorded at December 31, 2023. The recoverable amount for each CGU was based on the estimated cash flows associated with proved and probable oil and gas reserves from an independent reserve report prepared as at December 31, 2023 utilizing a discount rate based on Baytex's corporate weighted average cost of capital adjusted for asset specific factors. The after-tax discount rates applied to the cash flows were between 12% and 14%.

At December 31, 2023, the recoverable amounts of the two CGUs were calculated using the following benchmark reference prices for the years 2024 to 2033 adjusted for commodity differentials specific to the CGU. The prices and costs subsequent to 2033 have been adjusted for inflation at an annual rate of 2.0%.

	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
WTI crude oil (US$/bbl)	73.67	74.98	76.14	77.66	79.22	80.80	82.42	84.06	85.74	87.46
LLS crude oil (US$/bbl)	76.49	77.80	78.95	80.35	81.95	83.59	85.27	86.97	88.71	90.48
Edmonton par oil ($/bbl)	92.91	95.04	96.07	97.99	99.95	101.94	103.98	106.06	108.18	110.35
NYMEX Henry Hub gas (US$/mmbtu)	2.75	3.64	4.02	4.10	4.18	4.27	4.35	4.44	4.53	4.62
AECO gas ($/mmbtu)	2.20	3.37	4.05	4.13	4.21	4.30	4.38	4.47	4.56	4.65
Exchange rate (CAD/USD)	0.75	0.75	0.76	0.76	0.76	0.76	0.76	0.76	0.76	0.76

The following table summarizes the recoverable amount and impairment for each of the two CGUs at December 31, 2023 and demonstrates the sensitivity of the impairment to reasonably possible changes in key assumptions inherent in the calculation.

	Recoverable amount	Impairment loss	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Viking CGU	$ 606,290	$ 184,000	$ 26,500	$ 53,000	$ 3,500
Eagle Ford Non-operated CGU (1)	1,429,658	649,662	71,300	107,600	25,700

(1) There were no indicators of impairment identified for the Eagle Ford Operated CGU which includes the assets acquired from Ranger (note 4).

8. CREDIT FACILITIES

	December 31, 2024	December 31, 2023
Credit facilities - U.S. dollar denominated (1)	**$ 206,826**	$ 311,980
Credit facilities - Canadian dollar denominated	**134,381**	552,756
Credit facilities - principal (2)	**$ 341,207**	$ 864,736
Unamortized debt issuance costs	**(16,861)**	(15,987)
Credit facilities	**$ 324,346**	$ 848,749

(1) U.S. dollar denominated credit facilities balance was US$143.6 million as at December 31, 2024 (December 31, 2023 - US$236.3 million).

(2) The decrease in the principal amount of the credit facilities outstanding from December 31, 2023 to December 31, 2024 is the result of net repayments of $539.7 million, partially offset by an increase in the reported amount of U.S. denominated debt of $16.2 million due to foreign exchange.

On May 9, 2024, Baytex extended the maturity of the US$1.1 billion revolving credit facilities (the "Credit Facilities") from April 1, 2026 to May 9, 2028. There are no changes to the loan balances or financial covenants as a result of the amendment. Following the amendment, borrowings in Canadian funds previously based on the banker's acceptance rate have been replaced with borrowings based on the Canadian Overnight Repo Rate Average ("CORRA").

At December 31, 2024, 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 7.6% for the year ended December 31, 2024 (7.4% for the year ended December 31, 2023).

The following table summarizes the financial covenants applicable to the Credit Facilities and the Company's compliance therewith at December 31, 2024.

Covenant Description	Position as at December 31, 2024	Covenant
Senior Secured Debt [1] to Bank EBITDA [2] (Maximum Ratio)	**0.2:1.0**	3.5:1.0
Interest Coverage [3] (Minimum Ratio)	**10.7:1.0**	3.5:1.0
Total Debt [4] to Bank EBITDA [2] (Maximum Ratio)	**1.1:1.0**	4.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at December 31, 2024, the Company's Senior Secured Debt totaled $345.9 million.

(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit facility agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the year ended December 31, 2024 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 expenses, 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 expenses for the year ended December 31, 2024 was $204.5 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 December 31, 2024, the Company's Total Debt totaled $2.3 billion of principal amounts outstanding.

At December 31, 2024, Baytex had $5.8 million of outstanding letters of credit (December 31, 2023 - $5.6 million outstanding).

9. LONG-TERM NOTES

	December 31, 2024	December 31, 2023
8.75% notes due April 1, 2027 [1]	**$ —**	$ 541,114
8.50% notes due April 30, 2030 [2]	**1,152,360**	1,056,361
7.375% notes due March 15, 2032 [3]	**828,259**	—
Total long-term notes - principal [4]	**$ 1,980,619**	$ 1,597,475
Unamortized debt issuance costs	**(47,729)**	(35,114)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,932,890**	$ 1,562,361

(1) The 8.75% notes were fully repaid on April 1, 2024. The U.S. dollar denominated principal outstanding of the 8.75% notes was US$409.8 million as at December 31, 2023.

(2) The U.S. dollar denominated principal outstanding of the 8.50% notes was US$800.0 million as at December 31, 2024 (December 31, 2023 - US$800.0 million).

(3) The U.S. dollar denominated principal outstanding of the 7.375% notes was US$575.0 million as at December 31, 2024 (December 31, 2023 - nil).

(4) The increase in the principal amount of long-term notes outstanding from December 31, 2023 to December 31, 2024 is the result of the issuance of the 7.375% notes for $780.9 million and changes in the reported amount of U.S. denominated debt of $158.8 million due to changes in the CAD/USD exchange rate used to translate the U.S. denominated amount of long-term notes outstanding. This was partially offset by the repayment of the 8.75% notes for $556.6 million.

On April 1, 2024, Baytex closed a private offering of the US$575 million aggregate principal amount of senior unsecured notes due 2032 ("7.375% Senior Notes"). The 7.375% Senior Notes were priced at 99.266% of par to yield 7.500% per annum, bear interest at a rate of 7.375% per annum and mature on March 15, 2032. 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. Proceeds from the 7.375% Senior Notes were used to redeem the remaining US$409.8 million aggregate principal amount of the outstanding 8.75% Senior Notes at 104.375% of par value, pay the related fees and expenses associated with the offering, and repay a portion of the debt outstanding on our Credit Facilities. During Q2 2024, Baytex recorded early redemption expense of $24.4 million which is the call premium paid on the redemption of the 8.75% Senior Notes.

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 were issued at 98.709% of par and 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. Net proceeds of $1.0 billion reflects $13.7 million for the original issue discount and Baytex also incurred transaction costs of $18.5 million in conjunction with the issuance.

The long-term notes do not contain any significant financial maintenance covenants but do contain standard commercial covenants for 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. These standard commercial covenants do not prohibit the incurrence of indebtedness under the Credit Facilities, as long as the total debt incurred, including the Credit Facilities, does not exceed a specified threshold. Baytex continues to be in compliance with all financial and commercial covenants under its debt agreements.

10. ASSET RETIREMENT OBLIGATIONS

	December 31, 2024	December 31, 2023
Balance, beginning of year	**$ 623,399**	$ 588,923
Liabilities incurred (1)	**32,635**	24,185
Liabilities settled	**(28,793)**	(26,416)
Liabilities assumed from corporate acquisition (note 4)	**—**	31,310
Liabilities acquired from property acquisitions	**814**	87
Liabilities divested	**(9,482)**	(43,153)
Accretion (note 16)	**21,226**	20,406
Government grants (2)	**—**	(1,271)
Change in estimate (1)	**10,113**	17,067
Changes in discount rates and inflation rates (1)(3)	**(17,495)**	12,914
Foreign currency translation	**8,534**	(653)
Balance, end of year	**$ 640,951**	$ 623,399
Less current portion of asset retirement obligations	**15,656**	20,448
Non-current portion of asset retirement obligations	**$ 625,295**	$ 602,951

(1) The total of these items reflects the total change in asset retirement obligations of $25.3 million per Note 7 - Oil and Gas Properties ($54.2 million increase in 2023).

(2) Certain government grants were provided by the Government of Alberta and the Government of Saskatchewan under programs that were completed during the year ended December 31, 2023. During the year ended December 31, 2024, no amounts have been recognized under these programs ($1.3 million for the year ended December 31, 2023).

(3) The discount and inflation rates used to calculate the liability for our Canadian operations at December 31, 2024 were 3.3% and 1.8% respectively (December 31, 2023 - 3.0% and 1.6%). The discount and inflation rates used to calculate the liability for our U.S. operations at December 31, 2024 were 4.8% and 2.3%, respectively (December 31, 2023 - 4.0% and 2.1%).

At December 31, 2024, the undiscounted, uninflated amount of estimated cash flows required to settle the asset retirement obligations is $845.0 million (December 31, 2023 - $795.5 million). The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2024 is $641.0 million (December 31, 2023 - $623.4 million). These costs are expected to be incurred over the next 55 years.

11. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at December 31, 2024, 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, 2022	**544,930**	**$ 5,499,664**
Issued on corporate acquisition (note 4)	311,370	1,326,435
Vesting of share awards	5,892	26,229
Common shares repurchased and cancelled	(40,511)	(325,039)
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**

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 year ended December 31, 2024, Baytex recorded $222.2 million related to common share repurchases, which includes $217.9 million of consideration paid for the repurchase and cancellation of common shares as well as $4.3 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 year ended December 31, 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. During 2023, Baytex repurchased and cancelled 40.5 million common shares at an average price of $5.48 per share for total consideration of $221.9 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.

Effective January 1, 2024, the Government of Canada introduced a 2% federal tax on equity repurchases. During the year ended December 31, 2024, Baytex recorded a $4.3 million liability, charged to shareholders’ capital, related to the federal tax on equity repurchases.

Dividends

The following dividends were declared by Baytex during the year ended December 31, 2024:

Record Date	Payable Date	Per Share Amount		Dividend Amount	
March 15, 2024	April 1, 2024	$	0.0225	$	18,494
June 14, 2024	July 2, 2024		0.0225		18,161
September 16, 2024	October 1, 2024		0.0225		17,732
December 16, 2024	January 2, 2025		0.0225		17,598
Total dividends declared				**$**	**71,985**

On March 4, 2025, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on April 1, 2025 for shareholders of record on March 14, 2025.

12. SHARE-BASED COMPENSATION PLAN

For the year ended December 31, 2024, the Company recorded total share-based compensation expense of $17.9 million ($37.7 million for the year ended December 31, 2023) which is related to cash-settled awards.

The Company's closing share price on December 31, 2024 was $3.70 (December 31, 2023 - $4.38).

The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plans of the Company) shall not exceed 3.8% of the then-issued and outstanding common shares.

Liabilities associated with cash-settled awards are determined based on the fair value of the award at grant date and are subsequently revalued at each period end until the date of settlement. This valuation incorporates the period-end share price, the number of awards outstanding at each period end, and certain management estimates, such as estimated forfeitures and performance multiplier, if applicable. Share-based compensation expense related to cash-settled awards is recognized in the consolidated statements of income (loss) and comprehensive income (loss) over the relevant service period with a corresponding increase or decrease in share-based compensation liability. Classification of the associated short-term and long-term liabilities is dependent on the expected payout dates of the individual awards.

Share Award Incentive Plan

The Company has a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards (collectively, "Share Awards") may be granted to directors, officers and employees of the Company and its subsidiaries. Pursuant to the Share Award Incentive Plan, Baytex has the option to settle amounts payable related to Share Awards in cash on the settlement date.

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 cash equivalent 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 Board of Directors on an annual basis. The multiplier is dependent on the performance of the Company relative to predefined corporate performance measures for a particular period. The number of Share Awards is adjusted to account for the payment of dividends from the grant date to the applicable issue date. The Share Awards vest in equal tranches on the first, second and third anniversaries of the grant date and are expensed over the vesting period using the graded vesting method. The cumulative expense is recognized at fair value at each period end and is included in share-based compensation liability.

In 2023, Baytex became the successor to Ranger's Share Award Plan (note 4). Awards outstanding as at the closing date of the acquisition were converted to restricted awards that will be settled in shares of Baytex or with cash, with the quantity outstanding adjusted based on the exchange ratio for the business combination with Ranger.

The weighted average fair value of Share Awards granted during the year ended December 31, 2024 was $4.24 per restricted and performance award ($5.40 for the year ended December 31, 2023).

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 and are expensed over the vesting period using the graded vesting method. 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 year ended December 31, 2024 was $4.34 per incentive award ($5.35 for the year ended December 31, 2023).

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 year ended December 31, 2024 was $4.46 per DSU award ($5.15 for the year ended December 31, 2023).

The number of awards outstanding is detailed below:

(000s)	Restricted awards	Performance awards	Incentive awards	Director Share Units	Total
Balance, December 31, 2022	**762**	**4,796**	**5,109**	**967**	**11,634**
Granted	41	2,641	2,607	278	5,567
Assumed on corporate acquisition [(1)]	10,789	—	—	—	10,789
Vested	(9,302)	(3,767)	(2,715)	—	(15,784)
Forfeited	(11)	(315)	(518)	—	(844)
Balance, 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)
Balance, December 31, 2024	**826**	**3,482**	**5,275**	**1,418**	**11,001**

(1) Following the closing of the transaction, holders of awards outstanding under Ranger's Share Award Plan were entitled to Baytex common shares rather than Ranger common shares with adjustment to the quantity outstanding based on the exchange ratio for Ranger shares. The fair value of share awards allocated to consideration was based on the service period that had occurred prior to the acquisition date (note 4) while the remaining fair value of the share awards assumed by Baytex is recognized over the remaining future service periods.

13. 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 year.

	Years Ended December 31					
	2024			2023		
	Net income	**Weighted average common shares (000's)**	**Net income per share**	Net loss	Weighted average common shares (000's)	Net loss per share
Net income (loss) - basic	**$ 236,597**	**803,435**	**$ 0.29**	$ (233,356)	704,896	$ (0.33)
Dilutive effect of share awards	**—**	**4,276**	**—**	—	—	—
Net income (loss) - diluted	**$ 236,597**	**807,711**	**$ 0.29**	$ (233,356)	704,896	$ (0.33)

For the year ended December 31, 2024, no share awards were excluded from the calculation of diluted income per share as their effect was dilutive. For the year ended December 31, 2023, 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.

14. 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.

	Years Ended December 31					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 421,383**	**$ 2,063,677**	**$ 2,485,060**	$ 574,910	$ 1,454,213	$ 2,029,123
Heavy oil	**1,403,022**	**—**	**1,403,022**	1,081,549	—	1,081,549
NGL	**26,017**	**176,289**	**202,306**	23,174	122,823	145,997
Natural gas	**23,624**	**94,943**	**118,567**	49,388	76,564	125,952
Total petroleum and natural gas sales	**$ 1,874,046**	**$ 2,334,909**	**$ 4,208,955**	$ 1,729,021	$ 1,653,600	$ 3,382,621

Included in trade receivables at December 31, 2024 is $325.7 million of accrued receivables related to delivered volumes (December 31, 2023 - $271.1 million).

15. INCOME TAXES

The provision for income taxes has been computed as follows:

	Years Ended December 31	
	2024	2023
Net income (loss) before income taxes	**$ 373,290**	$ (516,582)
Expected income taxes at the statutory rate of 24.38% (2023 – 24.64%) (1)	**91,008**	(127,286)
Increase (decrease) in income taxes resulting from:		
Effect of foreign exchange	**19,354**	(2,089)
Effect of change in statutory rates (2)	**8,287**	—
Effect of rate adjustments for foreign jurisdictions	**(8,187)**	5,062
Effect of change in deferred tax benefit not recognized (3)	**(6,349)**	6,347
Effect of internal debt restructuring (4)	**—**	(186,460)
Repatriation and related taxes	**24,914**	13,565
Adjustments, assessments and other	**7,666**	7,635
Income tax expense (recovery)	**$ 136,693**	$ (283,226)

(1) The expected income tax rate decreased due to changes in the provincial apportionment of Canadian income.
(2) On December 11, 2024, Luxembourg enacted a reduction of the statutory corporate income tax rate to 23.87% from 24.94%, applicable to tax years beginning on January 1, 2025. This change resulted in a deferred tax expense in 2024 on the deferred tax assets of Baytex's Luxembourg subsidiary.
(3) A deferred tax asset of $31.8 million remains unrecognized due to uncertainty surrounding future capital gains (December 31, 2023 - $40.4 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.
(4) A deferred income tax asset has been recognized immediately after the closing of the Ranger acquisition due to effects of the transaction structuring.

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 (described below) 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.

For the year-ended December 31, 2024, Baytex has determined that it meets the requirements of safe-harbor provisions in all the jurisdictions in which we operate and therefore does not anticipate owing any top-up taxes under Pillar Two legislation.

A continuity of the net deferred income tax asset or liability is detailed in the following tables:

As at	January 1, 2024	Recognized in Net Income	Foreign Currency Translation Adjustment	**December 31, 2024**
Taxable temporary differences:				
Petroleum and natural gas properties	$ (706,101)	$ (100,286)	$ (41,934)	**$ (848,321)**
Financial derivatives	(2,738)	(3,096)	—	**(5,834)**
Other	(13,046)	(1,434)	(119)	**(14,599)**
Deductible temporary differences:				
Asset retirement obligations	150,856	1,138	1,811	**153,805**
Non-capital losses (1)(2)	647,561	(44,671)	45,452	**648,342**
Finance costs	115,280	33,422	7,556	**156,258**
Net deferred income tax asset (liability) (3)	$ 191,812	$ (114,927)	$ 12,766	**$ 89,651**

(1) Non-capital loss carry-forwards at December 31, 2024 totaled $3.3 billion, of which $1.8 billion will expire from 2032 to 2043, and $1.5 billion does not have an expiry date.
(2) A deferred income tax asset of $178.2 million has been recognized in respect of non-capital losses of a wholly owned financing subsidiary of Baytex; which losses will be offset against future interest income to be earned as a result of an internal debt restructuring.
(3) The net deferred income tax asset as at December 31, 2024 is comprised of a deferred income tax asset of $178.2 million and a deferred income tax liability of $88.6 million.

As at	January 1, 2023	Recognized in Net Loss	Business Combination	Foreign Currency Translation Adjustment	**December 31, 2023**
Taxable temporary differences:					
Petroleum and natural gas properties	$ (807,514)	$ 200,623	$ (111,131)	$ 11,921	**$ (706,101)**
Financial derivatives	(2,506)	4,506	(4,738)	—	**(2,738)**
Other	(20,951)	8,225	—	(320)	**(13,046)**
Deductible temporary differences:					
Asset retirement obligations	145,275	(873)	6,575	(121)	**150,856**
Non-capital losses (1)(2)	416,131	79,343	156,385	(4,298)	**647,561**
Finance costs	60,951	5,805	53,761	(5,237)	**115,280**
Net deferred income tax (liability) asset (3)	$ (208,614)	$ 297,629	$ 100,852	$ 1,945	**$ 191,812**

(1) Non-capital loss carry-forwards at December 31, 2023 totaled $3.2 billion, of which $2.6 billion will expire from 2033 to 2040, and $575.7 million does not have an expiry date.
(2) A deferred income tax asset of $213.1 million has been recognized in respect of non-capital losses of a wholly owned financing subsidiary of Baytex; which losses will be offset against future interest income to be earned as a result of an internal debt restructuring.
(3) The net deferred income tax asset as at December 31, 2023 is comprised of a deferred income tax asset of $213.1 million and a deferred income tax liability of $21.3 million.

16. FINANCING AND INTEREST

	Years Ended December 31	
	2024	2023
Interest on Credit Facilities	**$ 55,498**	$ 56,713
Interest on long-term notes	**148,968**	102,426
Interest on lease obligations	**1,638**	684
Cash interest	**$ 206,104**	$ 159,823
Amortization of debt issue costs	**16,694**	11,944
Accretion of asset retirement obligations (note 10)	**21,226**	20,406
Early redemption expense	**24,350**	—
Financing and interest	**$ 268,374**	$ 192,173

17. FOREIGN EXCHANGE

	Years Ended December 31	
	2024	2023
Unrealized foreign exchange loss (gain)	**$ 153,930**	$ (14,300)
Realized foreign exchange loss	**1,965**	3,452
Foreign exchange loss (gain)	**$ 155,895**	$ (10,848)

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade receivables, trade payables, dividends payable, financial derivatives, Credit Facilities and long-term notes. The fair value of cash, trade receivables, trade payables and dividends payable approximates carrying value due to the short term to maturity. The fair value of the Credit Facilities is equal to the principal amount outstanding as the Credit Facilities bear interest at floating rates and credit spreads that are indicative of market rates. The fair value of the long-term notes is determined based on market prices.

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

	December 31, 2024		December 31, 2023		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial Derivatives	**$ 25,573**	**$ 25,573**	$ 23,274	$ 23,274	Level 2
Total	**$ 25,573**	**$ 25,573**	$ 23,274	$ 23,274	
Amortized cost					
Cash	**$ 16,610**	**$ 16,610**	$ 55,815	$ 55,815	—
Trade receivables	**387,266**	**387,266**	339,405	339,405	
Total	**$ 403,876**	**$ 403,876**	$ 395,220	$ 395,220	
Financial Liabilities					
FVTPL					
Financial Derivatives	**$ (1,645)**	**$ (1,645)**	$ —	$ —	Level 2
Total	**$ (1,645)**	**$ (1,645)**	$ —	$ —	
Amortized cost					
Trade payables	**$ (512,473)**	**$ (512,473)**	$ (477,295)	$ (477,295)	—
Dividends payable	**(17,598)**	**(17,598)**	(18,381)	(18,381)	—
Credit Facilities (1)	**(324,346)**	**(341,207)**	(848,749)	(864,736)	—
Long-term notes	**(1,932,890)**	**(1,990,598)**	(1,562,361)	(1,653,118)	Level 1
Total	**$ (2,787,307)**	**$ (2,861,876)**	$ (2,906,786)	$ (3,013,530)	

(1) The difference in the carrying value and fair value of the Credit Facilities is due to unamortized debt issuance costs. Refer to Note 8.

Baytex classifies the fair value of financial instruments according to the following hierarchy based on the number of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

There were no transfers between Level 1 and Level 2 during the years ended December 31, 2024 or 2023.

Foreign Currency Risk

In entities with a Canadian dollar functional currency, Baytex is exposed to fluctuations in foreign exchange rates as a result of the U.S. dollar portion of its Credit Facilities, long-term notes and crude oil sales based on U.S. dollar benchmark prices. The Company's net income or loss, comprehensive income or loss and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

A $0.01 increase or decrease in the CAD/USD foreign exchange rate on the revaluation of outstanding U.S. dollar denominated assets and liabilities would impact net income or loss before income taxes by approximately $13.8 million.

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	
	December 31, 2024	December 31, 2023	**December 31, 2024**	December 31, 2023
U.S. dollar denominated	**US$21,450**	US$17,923	**US$1,399,881**	US$1,249,725

Interest Rate Risk

The Company's interest rate risk arises from borrowing at floating rates under the Credit Facilities (note 8). Based on the principal outstanding on the Credit Facilities as at December 31, 2024, a 1% change in interest rates would impact net income or loss before income taxes by approximately $3.4 million for an annual period.

Commodity Price Risk

Baytex utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivatives is governed by a Risk Management Policy approved by the Board of Directors of Baytex which sets out limits on the use of derivatives. Baytex does not use financial derivatives for speculative purposes.

The reported value of commodity financial derivatives is sensitive to changes in forecasted commodity prices. For crude oil contracts outstanding as at December 31, 2024, a US$1.00/bbl change in the underlying benchmark crude oil prices would impact net income before income taxes by approximately $29.7 million. For natural gas and natural gas liquids contracts outstanding as at December 31, 2024, a US$0.25 change in the underlying benchmark natural gas or natural gas liquids prices would impact net income or loss before income taxes by approximately $9.6 million.

Financial Derivative Contracts

Baytex had the following commodity financial derivative contracts outstanding as at March 4, 2025.

	Remaining Period	Volume	Price/Unit [1]	Index
Oil				
Basis differential	Jan 2025 to Dec 2025	2,000 bbl/d	WTI less US$2.75/bbl	MSW
Basis differential	Jan 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	Jan 2025 to Dec 2025	14,000 bbl/d	WTI less US$13.10/bbl	WCS
Basis differential [3]	Apr 2025 to Dec 2025	5,000 bbl/d	WTI less US$13.50/bbl	WCS
Collar	Jan 2025 to Mar 2025	5,000 bbl/d	US$60.00/US$88.70	WTI
Collar	Jan 2025 to Mar 2025	2,500 bbl/d	US$60.00/US$90.20	WTI
Collar	Jan 2025 to Mar 2025	2,500 bbl/d	US$60.00/US$90.05	WTI
Collar	Jan 2025 to Mar 2025	7,500 bbl/d	US$60.00/US$90.00	WTI
Collar	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$94.25	WTI
Collar	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$93.90	WTI
Collar	Jan 2025 to Jun 2025	5,000 bbl/d	US$60.00/US$91.95	WTI
Collar	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$90.00	WTI
Collar	Jan 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	Jan 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	Jan 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.01	NYMEX
Collar	Jan 2025 to Dec 2025	5,000 mmbtu/d	US$3.25/US$4.03	NYMEX
Collar	Jan 2025 to Dec 2025	5,000 mmbtu/d	US$3.25/US$4.08	NYMEX
Collar	Jan 2025 to Dec 2025	3,000 mmbtu/d	US$3.25/US$4.135	NYMEX
Collar	Jan 2025 to Dec 2025	5,500 mmbtu/d	US$3.25/US$4.14	NYMEX
Collar	Jan 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.32	NYMEX
Collar	Jan 2025 to Dec 2025	3,000 mmbtu/d	US$3.00/US$4.85	NYMEX
Collar	Jan 2025 to Dec 2025	8,000 mmbtu/d	US$3.00/US$4.855	NYMEX
Collar	Jan 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
AECO basis differential	Jan 2025 to Mar 2025	5,000 mmbtu/d	NYMEX less US$1.27/mmbtu	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 December 31, 2024.

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

	Years Ended December 31	
	2024	2023
Realized financial derivatives gain	**$ (1,447)**	$ (36,212)
Unrealized financial derivatives (gain) loss	**(654)**	11,517
Financial derivatives gain	**$ (2,101)**	$ (24,695)

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include management of forecasted and actual cash flows from operating, financing and investing activities, available capacity under the existing Credit Facilities, and opportunities to issue additional debt or equity securities.

The timing of cash outflows relating to financial liabilities as at December 31, 2024 is outlined in the table below:

	Total	2025	2026-2027	2028-2029	2030 and beyond
Trade payables	**$ 512,473**	$ 512,473	$ —	$ —	$ —
Financial derivatives	**1,645**	—	1,645	—	—
Credit Facilities - principal	**341,207**	—	—	341,207	—
Long-term notes - principal (1)	**1,980,619**	—	—	—	1,980,619
Interest on long-term notes (2)	**962,531**	159,035	318,069	318,069	167,358
	$ 3,798,475	**$ 671,508**	**$ 319,714**	**$ 659,276**	**$ 2,147,977**

(1) The US$800.0 million principal amount of 8.50% senior unsecured notes is due April 30, 2030 and the US$575.0 million principal amount of 7.375% senior unsecured notes is due March 15, 2032.

(2) Excludes interest on Credit Facilities as interest payments on Credit Facilities fluctuate based on amounts outstanding and the prevailing interest rate at the time of borrowing.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. As at December 31, 2024, the Company is exposed to credit risk with respect to its cash, trade receivables and financial derivatives. Baytex manages these risks through the selection and monitoring of credit-worthy counterparties.

Most of the Company's trade receivables relate to petroleum and natural gas sales. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts after reviewing the creditworthiness of the entity. Letters of credit or parental guarantees may be obtained prior to the commencement of business with certain counterparties. Credit risk may also arise from financial derivative instruments. Baytex's financial derivative contracts are subject to master netting agreements that create a legally enforceable right to offset by the counterparty the related financial assets and financial liabilities. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers all financial assets that are not impaired or past due to be of good credit quality.

The majority of the Company's credit exposure on trade receivables at December 31, 2024 relates to accrued revenues. Accounts receivable from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production.

Should the Company determine that the ultimate collection of a receivable is in doubt, the carrying amount of trade receivables is reduced by adjusting the allowance for doubtful accounts and recording a charge to net income or loss. If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. As at December 31, 2024, allowance for doubtful accounts was $1.0 million (December 31, 2023 - $1.5 million).

In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. Baytex has estimated the lifetime expected credit loss as at and for the year ended December 31, 2024 to be nominal.

The Company's trade receivables, net of the allowance for doubtful accounts, were aged as follows:

	December 31, 2024	December 31, 2023
Current (less than 30 days)	**$ 383,968**	$ 321,450
31-60 days	**1,224**	14,836
61-90 days	**492**	461
Past due (more than 90 days)	**1,582**	2,658
	$ 387,266	$ 339,405

19. SUPPLEMENTAL INFORMATION

Changes in Non-Cash Working Capital Items

	Years Ended December 31	
	2024	2023
Trade receivables	**$ (47,861)**	$ (117,297)
Prepaids and other assets	**8,531**	(76,882)
Trade payables	**35,178**	236,560
Share-based compensation liability	**(11,000)**	(18,340)
Dividends payable	**(783)**	18,381
Non-cash working capital disposed or acquired (note 4)	**(6,390)**	(230,012)
	$ (22,325)	$ (187,590)
Changes in non-cash working capital related to:		
Operating activities	**$ (17,922)**	$ (220,895)
Financing activities	**6,200**	(3,068)
Investing activities	**(11,375)**	46,810
Transfers to equity	**(1,167)**	—
Foreign currency translation on non-cash working capital	**1,939**	(10,437)
	$ (22,325)	$ (187,590)

Income Statement Presentation

Baytex's consolidated statements of income (loss) and comprehensive income (loss) are prepared according to the nature of expense, with the exception of employee compensation costs which are included in both operating expense and general and administrative expense line items.

The following table details the amount of total employee compensation costs included in the operating expense and general and administrative expense.

	Years Ended December 31	
	2024	2023
Operating	**$ 24,287**	$ 17,975
General and administrative	**64,065**	49,633
Total employee compensation costs	**$ 88,352**	$ 67,608

20. COMMITMENTS

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's cash flow from operations in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow (note 22). These obligations as of December 31, 2024 and the expected timing of funding of these obligations, are noted in the table below.

	Total	2024	2025-2026	2027-2028	2029 and beyond
Processing agreements	**$ 5,917**	$ 948	$ 1,239	$ 543	$ 3,187
Transportation agreements	**168,767**	54,909	84,742	17,877	11,239
Total	**$ 174,684**	**$ 55,857**	**$ 85,981**	**$ 18,420**	**$ 14,426**

Baytex also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives (note 10). 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 wellsites and facilities are undertaken regularly in accordance with applicable legislative requirements.

21. RELATED PARTIES

Transactions with key management personnel and directors are noted in the table below.

	Years Ended December 31	
	2024	2023
Short-term employee benefits	**$ 7,341**	$ 7,753
Share-based compensation	**10,034**	9,924
Total compensation for key management personnel	**$ 17,375**	$ 17,677

22. 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 December 31, 2024, 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 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.

	December 31, 2024	December 31, 2023
Credit Facilities	**$ 324,346**	$ 848,749
Unamortized debt issuance costs - Credit Facilities (note 8)	**16,861**	15,987
Long-term notes	**1,932,890**	1,562,361
Unamortized debt issuance costs - Long-term notes (note 9)	**47,729**	35,114
Trade payables	**512,473**	477,295
Dividends payable	**17,598**	18,381
Share-based compensation liability	**24,732**	35,732
Other long-term liabilities	**20,887**	19,147
Cash	**(16,610)**	(55,815)
Trade receivables	**(387,266)**	(339,405)
Prepaids and other assets	**(76,468)**	(83,259)
Net Debt	**$ 2,417,172**	$ 2,534,287

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, transaction costs and cash premiums on derivatives.

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

	Years Ended December 31	
	2024	2023
Cash flows from operating activities	**$ 1,908,264**	$ 1,295,731
Change in non-cash working capital	**17,922**	220,895
Asset retirement obligations settled	**28,793**	26,416
Transaction costs	**1,539**	49,045
Cash premiums on derivatives	**—**	2,263
Adjusted Funds Flow	**$ 1,956,518**	$ 1,594,350