BAYTEX ANNOUNCES FIRST QUARTER 2024 RESULTS

CALGARY, ALBERTA (May 9, 2024) - Baytex Energy Corp. ("Baytex") (TSX:BTE) (NYSE:BTE) reports its operating and financial results for the three months ended March 31, 2024 (all amounts are in Canadian dollars unless otherwise noted).

"In the first quarter we safely and efficiently executed the largest exploration and development ("E&D") program in company history and delivered operating and financial results consistent with our full-year guidance. We expect to deliver substantial free cash flow and meaningful shareholder returns over the next three quarters. Our strong free cash flow profile reflects the efficiency of our E&D program, higher forecast production volumes for the remainder of the year and improved crude oil price realizations in Canada and the Eagle Ford. We are in a strong financial position supported by significant liquidity and a balanced debt maturity profile," commented Eric T. Greager, President and Chief Executive Officer.

Highlights

- Reported cash flows from operating activities of $384 million ($0.47 per basic share) in Q1/2024.
- Increased adjusted funds flow(1) per share by 21% to $424 million ($0.52 per basic share) in Q1/2024 compared to Q1/2023.
- Increased production per share by 15% in Q1/2024, compared to Q1/2023. Production in Q1/2024 averaged 150,620 boe/d (84% oil and NGL), consistent with our full-year plan.
- Executed a $413 million E&D program, the largest in company history which, at its peak, had 13 rigs running.
- Brought 19 operated Eagle Ford wells onstream in Q1/2024, including three Upper Eagle Ford wells and a successful Lower Eagle Ford refrac.
- Generated production from our Clearwater play at Peavine of 17,599 bbl/d in Q1/2024. Brought 12 wells onstream in Q1/2024 that generated an average 30-day initial production rate of 915 bbl/d per well.
- Completed the drilling of our seven-well Duvernay program with a 21% improvement in drilling days (spud to rig release) and a 10% improvement in drilling costs, compared to 2023.
- Continued development success at Morinville, Alberta (Clearwater equivalent) and the greater Cold Lake region (Waseca).
- Maintained balance sheet strength and with a total debt(2) to Bank EBITDA(2) ratio of 1.1x.
- Subsequent to quarter-end, completed a US$575 million private placement offering of senior unsecured notes due 2032 that bear interest at a rate of 7.375% per annum and extended the maturity of our credit facilities by two years to May 2028.

2024 Guidance

Our 2024 guidance remains unchanged with E&D expenditures of $1.2 to $1.3 billion and production of 150,000 to 156,000 boe/d.

Based on the forward strip(3), we expect to generate approximately $700 million of free cash flow(4) in 2024. We intend to allocate 50% of free cash flow to the balance sheet and 50% to shareholder returns, which includes a combination of share buybacks and a quarterly dividend.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.
(3) 2024 pricing assumptions: WTI - US$77.50/bbl; WCS differential - US$14.50/bbl; NYMEX Gas - US$2.40/MMbtu; and Exchange Rate (CAD/USD) - 1.36.
(4) 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.

	Three Months Ended		
	March 31, 2024	December 31, 2023	March 31, 2023
FINANCIAL (thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales	**$ 984,192**	$ 1,065,515	$ 555,336
Adjusted funds flow [1]	**423,846**	502,148	236,989
Per share – basic	**0.52**	0.60	0.43
Per share – diluted	**0.52**	0.60	0.43
Free cash flow [2]	**(88)**	290,785	(1,918)
Per share – basic	**—**	0.35	—
Per share – diluted	**—**	0.35	—
Cash flows from operating activities	**383,773**	474,452	184,938
Per share – basic	**0.47**	0.57	0.34
Per share – diluted	**0.47**	0.57	0.34
Net (loss) income	**(14,043)**	(625,830)	51,441
Per share – basic	**(0.02)**	(0.75)	0.09
Per share – diluted	**(0.02)**	(0.75)	0.09
Dividends declared	**18,494**	18,381	—
Per share	**0.0225**	0.0225	—
Capital Expenditures			
Exploration and development expenditures	**$ 412,551**	$ 199,214	$ 233,626
Acquisitions and divestitures	**35,378**	(125,822)	271
Total oil and natural gas capital expenditures	**$ 447,929**	$ 73,392	$ 233,897
Net Debt			
Credit facilities	**$ 849,926**	$ 864,736	$ 409,653
Long-term notes	**1,637,155**	1,597,475	554,351
Total debt [3]	**2,487,081**	2,462,211	964,004
Working capital deficiency [2]	**152,760**	72,076	31,166
Net debt [1]	**$ 2,639,841**	$ 2,534,287	$ 995,170
Shares Outstanding - basic (thousands)			
Weighted average	**821,710**	831,063	545,062
End of period	**821,322**	821,681	545,553
BENCHMARK PRICES			
Crude oil			
WTI (US$/bbl)	**$ 76.96**	$ 78.32	$ 76.13
MEH oil (US$/bbl)	**78.95**	80.62	77.42
MEH oil differential to WTI (US$/bbl)	**1.99**	2.30	1.29
Edmonton par ($/bbl)	**92.16**	99.72	99.04
Edmonton par differential to WTI (US$/bbl)	**(8.63)**	(5.10)	(2.88)
WCS heavy oil ($/bbl)	**77.73**	76.86	69.44
WCS differential to WTI (US$/bbl)	**(19.33)**	(21.88)	(24.77)
Natural gas			
NYMEX (US$/mmbtu)	**$ 2.24**	$ 2.88	$ 3.42
AECO ($/mcf)	**2.05**	2.66	4.34
CAD/USD average exchange rate	**1.3488**	1.3619	1.3520

Notes:
(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.

	Three Months Ended		
	March 31, 2024	December 31, 2023	March 31, 2023
OPERATING			
Daily Production			
Light oil and condensate (bbl/d)	**66,036**	70,124	31,678
Heavy oil (bbl/d)	**40,560**	39,569	34,191
NGL (bbl/d)	**19,299**	23,160	7,213
Total liquids (bbl/d)	**125,895**	132,853	73,082
Natural gas (mcf/d)	**148,353**	165,121	82,066
Oil equivalent (boe/d @ 6:1) (1)	**150,620**	160,373	86,760
Netback (thousands of Canadian dollars)			
Total sales, net of blending and other expense (2)	**$ 919,984**	$ 1,003,219	$ 495,655
Royalties	**(209,171)**	(228,570)	(93,253)
Operating expense	**(173,435)**	(164,873)	(112,408)
Transportation expense	**(29,835)**	(29,744)	(17,005)
Operating netback (2)	**$ 507,543**	**$ 580,032**	**$ 272,989**
General and administrative	**(22,412)**	(22,280)	(11,734)
Cash financing and interest	**(53,280)**	(56,698)	(18,375)
Realized financial derivatives gain	**5,488**	12,377	5,415
Other (3)	**(13,493)**	(11,283)	(11,306)
Adjusted funds flow (4)	**$ 423,846**	**$ 502,148**	**$ 236,989**
Netback (per boe) (2)			
Total sales, net of blending and other expense (2)	**$ 67.12**	$ 68.00	$ 63.48
Royalties (5)	**(15.26)**	(15.49)	(11.94)
Operating expense (5)	**(12.65)**	(11.17)	(14.40)
Transportation expense (5)	**(2.18)**	(2.02)	(2.18)
Operating netback (2)	**$ 37.03**	**$ 39.32**	**$ 34.96**
General and administrative (5)	**(1.64)**	(1.51)	(1.50)
Cash financing and interest (5)	**(3.89)**	(3.84)	(2.35)
Realized financial derivatives gain (5)	**0.40**	0.84	0.69
Other (3)	**(0.98)**	(0.78)	(1.45)
Adjusted funds flow (4)	**$ 30.92**	**$ 34.03**	**$ 30.35**

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, other income or expense, current income tax expense or recovery and cash share-based compensation. Refer to the Q1/2024 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, transportation expense, general and administrative expense, cash interest expense or realized financial derivatives gain (loss) divided by barrels of oil equivalent production volume for the applicable period.

During the first quarter, we delivered operating and financial results consistent with our full-year guidance. We increased production per basic share by 15% in Q1/2024, compared to Q1/2023, with production averaging 150,620 boe/d (84% oil and NGLs). We increased adjusted funds flow[(1)] per basic share by 21% to $424 million ($0.52 per basic share) and realized a net loss of $14 million ($0.02 per basic share).

Our first quarter drilling program delivered strong results as we safely and efficiently executed the largest E&D program in company history. We drilled 92 (82.7 net) wells with 13 rigs running at the peak and E&D expenditures totaled $413 million (33% of budgeted full-year expenditures).

We remain committed to a disciplined, returns-based capital allocation philosophy to drive increased per-share returns. Our 2024 guidance remains unchanged with E&D expenditures of $1.2 to $1.3 billion and production of 150,000 to 156,000 boe/d. Based on the forward strip[(2)], we expect to generate approximately $700 million of free cash flow[(3)] in 2024, all of which is expected to be generated in the next three quarters. We intend to allocate 50% of free cash flow to the balance sheet and 50% to shareholder returns, which includes a combination of share buybacks and a quarterly dividend.

Our strong free cash flow profile for 2024 reflects the efficiency of our exploration and development program, higher forecast production volumes for the remainder of the year and improved crude oil price realizations in Canada and the Eagle Ford. In Canada, we are benefiting from the completion of the Trans Mountain Pipeline Expansion and increased oil export capacity which is contributing to a narrowing of the WTI-WCS spread. In the Eagle Ford, we benefit from our exposure to premium U.S. Gulf Coast pricing for our light oil and condensate production.

Our normal course issuer bid allows for the purchase of up to 68.4 million common shares during the 12-month period ending June 28, 2024 and we restarted our share buyback program in late March. For the period June 29, 2023 to May 8, 2024, we repurchased 47.0 million common shares for $255 million, representing 5.5% of our shares outstanding, at an average price of $5.42 per share.

Subsequent to quarter-end, we undertook steps to extend our debt maturities. On April 1, 2024, we closed a private placement offering of US$575 million aggregate principal amount of senior unsecured notes. The notes bear interest at a rate of 7.375% per annum and mature on March 15, 2032. Net proceeds from the offering were used to redeem US$409.8 million aggregate principal amount of outstanding 8.75% notes and repay a portion of the debt outstanding on our credit facilities. On May 9, 2024, we extended the maturity of our credit facilities by two years to May 2028.

We employ a disciplined commodity hedging program to help mitigate the volatility in revenue due to changes in commodity prices. In Q1/2024, our hedging program generated realized financial derivatives gains of $5 million. For the balance of 2024, we have entered into hedges on approximately 40% of our net crude oil exposure utilizing two-way collars with an average floor price of US$60/bbl and an average ceiling price of US$96/bbl. For H1/2025, we have entered into hedges on approximately 20% of our net crude oil exposure utilizing two-way collars with an average floor price of US$60/bbl and an average ceiling price of US$91/bbl. A complete listing of our financial derivative contracts can be found in Note 17 to our Q1/2024 financial statements.

Operations

In the Eagle Ford, we continue to deliver strong results across the black oil, volatile oil, and condensate thermal maturity windows. In Q1/2024, we brought 19 (18.5 net) operated wells onstream, including 15 Lower Eagle Ford wells, three Upper Eagle Ford wells, and one refrac.

During the first quarter, 10 of the 15 Lower Eagle Ford wells were on production for a sufficient amount of time to establish 30-day peak production rates. These wells generated an average 30-day initial peak production rate of 1,298 boe/d (85% oil and NGLs) per well. For 2024, we are targeting an 8% improvement in our operated drilling and completion costs per completed lateral foot over 2023. On our non-operated Eagle Ford acreage, we brought 18 (3.9 net) wells onstream.

We are focused on optimizing our acreage and have identified Upper Eagle Ford development areas. Our 2024 E&D program includes four Upper Eagle Ford wells, three of which were brought onstream during the first quarter and generated an average 30-day initial peak production rate of 1,214 boe/d per well (72% oil and NGLs). We completed a successful refrac (Medina Unit 3H) on our operated acreage during the first quarter that is expected to generate an internal rate of return of over 100%. Additional refrac opportunities have been identified to supplement to our capital program.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) 2024 pricing assumptions: WTI - US$77.50/bbl; WCS differential - US$14.50/bbl; NYMEX Gas - US$2.40/MMbtu; and Exchange Rate (CAD/USD) - 1.36.
(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 press release for further information.
(4) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.ca.

In our light oil business unit, we completed our 2024 drilling program in the Pembina Duvernay, expanded our land base and continued development in the Viking. We were pleased with the efficiency of our two-pad, seven-well drilling program in the Duvernay which saw a 21% improvement in drilling days (spud to rig release) and a 10% improvement in drilling costs, compared to 2023. Completion of the three-well pad commenced in April, and completion of the four-well pad is expected to commence in June. In the Viking, we brought 46 net wells onstream in Q1/2024.

In addition, we acquired 30.75 net sections of high-quality Duvernay lands adjacent to our existing acreage. This brings our core Duvernay acreage to 142 net sections. We believe the asset offers significant economic inventory and growth potential.

In our heavy oil business unit, Peavine continued to outperform expectations and we have followed up early exploration success in Morinville and the greater Cold Lake area. Our Clearwater production averaged 17,599 bbl/d during the first quarter, up 8% from Q4/2023. We brought 12 (12.0 net) wells onstream during Q1/2024 and initial well performance exceeded our internal type curve expectations. The 12 wells generated an average 30-day initial peak production rate of 915 bbl/d per well.

During the first quarter, we followed up our recent heavy oil exploration success at Morinville, Alberta. We brought four multi-lateral horizontal wells onstream that targeted the Rex formation (a Clearwater equivalent). At Morinville, we have aggregated approximately 30 sections of prospective lands and production has increased to over 1,000 bbl/d.

In the greater Cold Lake area, we recently brought five Waseca horizontal multi-lateral wells onstream, increasing production from the Waseca to over 1,000 bbl/d. At Angling Lake, we drilled two successful step-out wells targeting the Upper Waseca and a successful Lower Waseca follow-up. At Ethel Lake, we drilled our first two wells targeting the Upper Waseca and are encouraged by early-time productivity. We are planning five additional Waseca follow-up wells in H2/2024.

In addition, we completed a 13 well stratigraphic test program across our heavy oil acreage. The results will guide future exploration and development activity.

Quarterly Dividend

The Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on July 2, 2024 to shareholders of record on June 14, 2024.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three months ended March 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/edgar.shtml.

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: our expectation that we will deliver substantial free cash flow and meaningful shareholder returns over the next three quarters; for 2024: our guidance for exploration and development expenditures and production, the amount of free cash flow we expect to generate based on the forward strip and our expected allocation of that free cash flow as between the balance sheet and shareholder returns (including share buybacks and quarterly dividends); that we are committed to a disciplined, returns-based capital allocation philosophy to drive increased per-share returns; our expected reduction in total debt during 2024; our commodity hedging program, the percentage of our 2024 net crude exposure that is hedged, and the ability of such program to mitigate revenue volatility due to changes in commodity prices; in the Eagle Ford: our targeted improvement in operated drilling and completion costs per lateral foot in the Eagle Ford and the expected internal rate of return for the Medina Unit 3H refrac; our belief that the Duvernay asset offers significant economic inventory growth potential; drilling and completion plans for the Duvernay and Viking; and that stratigraphic test results on our heavy oil acreage will guide future exploration and development activity. 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; 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.

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, 2023 filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings. The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

This press release contains information that may be considered a financial outlook under applicable securities laws about the Corporation's potential financial position, including, but not limited to, our 2024 guidance for development expenditures; our expected 2024 free cash flow; and our intentions regarding the allocating our annual free cash flow; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the 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.

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 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.

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 are subject to the discretion of the Board of Directors of Baytex.

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

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

	Three Months Ended		
($ thousands)	**March 31, 2024**	December 31, 2023	March 31, 2023
Petroleum and natural gas sales	**$ 984,192**	$ 1,065,515	$ 555,336
Blending and other expense	**(64,208)**	(62,296)	(59,681)
Total sales, net of blending and other expense	**$ 919,984**	$ 1,003,219	$ 495,655
Royalties	**(209,171)**	(228,570)	(93,253)
Operating expense	**(173,435)**	(164,873)	(112,408)
Transportation expense	**(29,835)**	(29,744)	(17,005)
Operating netback	**$ 507,543**	$ 580,032	$ 272,989
Realized financial derivatives gain (1)	**5,488**	12,377	5,415
Operating netback after realized financial derivatives	**$ 513,031**	$ 592,409	$ 278,404

(1) Realized financial derivatives gain is a component of financial derivatives gain or loss. See Note 17 - Financial Instruments and Risk Management in the consolidated financial statements for the three months ended March 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, and transaction costs.

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

	Three Months Ended		
($ thousands)	**March 31, 2024**	December 31, 2023	March 31, 2023
Cash flows from operating activities	**$ 383,773**	$ 474,452	$ 184,938
Change in non-cash working capital	**32,023**	14,971	39,054
Additions to exploration and evaluation assets	**—**	5,079	(490)
Additions to oil and gas properties	**(412,551)**	1,271	(233,136)
Payments on lease obligations	**(4,872)**	(200,537)	(1,155)
Transaction costs	**1,539**	(4,451)	8,871
Free cash flow	**$ (88)**	$ 290,785	$ (1,918)

Working capital deficiency

Working capital deficiency is calculated as cash, trade receivables, prepaids and other assets net of trade payables, dividends payable, other long-term liabilities and share-based compensation liability. Working capital deficiency is used by management to measure the Company's liquidity. At March 31, 2024, the Company had $638.6 million of available credit facility capacity to cover any working capital deficiencies.

The following table summarizes the calculation of working capital deficiency.

	As at		
($ thousands)	**March 31, 2024**	December 31, 2023	March 31, 2023
Cash	**$ (29,140)**	$ (55,815)	$ (6,445)
Trade receivables	**(423,119)**	(339,405)	(221,007)
Prepaids and other assets	**(77,901)**	(83,259)	(12,404)
Trade payables	**626,137**	477,295	250,920
Share-based compensation liability	**18,667**	35,732	20,102
Other long-term liabilities	**19,622**	19,147	—
Dividends payable	**18,494**	18,381	—
Working capital deficiency	**$ 152,760**	$ 72,076	$ 31,166

Non-GAAP Financial Ratios

Total sales, net of blending and other expense per boe

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

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 equal to operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent sales volume for the applicable period and is used to assess our operating performance on a unit of production basis.

Capital Management Measures

Net debt

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

The following table summarizes our calculation of net debt.

	As at		
($ thousands)	**March 31, 2024**	December 31, 2023	March 31, 2023
Credit facilities	**$ 835,363**	$ 848,749	$ 407,473
Unamortized debt issuance costs - Credit facilities (1)	**14,563**	15,987	2,180
Long-term notes	**1,602,417**	1,562,361	547,698
Unamortized debt issuance costs - Long-term notes (1)	**34,738**	35,114	6,653
Trade payables	**626,137**	477,295	250,920
Share-based compensation liability	**18,667**	35,732	20,102
Dividends payable	**18,494**	18,381	—
Other long-term liabilities	**19,622**	19,147	—
Cash	**(29,140)**	(55,815)	(6,445)
Trade receivables	**(423,119)**	(339,405)	(221,007)
Prepaids and other assets	**(77,901)**	(83,259)	(12,404)
Net debt	**$ 2,639,841**	$ 2,534,287	$ 995,170

(1) Unamortized debt issuance costs were obtained from Note 7 - Credit Facilities and Note 8 - Long-term Notes from the consolidated financial statements for the three months ended March 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, and transaction costs during the applicable period.

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

	Three Months Ended		
($ thousands)	**March 31, 2024**	December 31, 2023	March 31, 2023
Cash flow from operating activities	**$ 383,773**	$ 474,452	$ 184,938
Change in non-cash working capital	**32,023**	14,971	39,054
Asset retirement obligations settled	**6,511**	7,646	4,126
Transaction costs	**1,539**	5,079	8,871
Adjusted funds flow	**$ 423,846**	$ 502,148	$ 236,989

Advisory Regarding Oil and Gas Information

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

References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

Throughout this press release, “oil and NGL” refers to heavy crude oil, bitumen, light and medium crude oil, tight oil, condensate and natural gas liquids (“NGL”) product types as defined by NI 51-101. The following table shows Baytex’s disaggregated production volumes for the three months ended March 31, 2024. The NI 51-101 product types are included as follows: “Heavy Crude Oil” - heavy crude oil and bitumen, “Light and Medium Crude Oil” - light and medium crude oil, tight oil and condensate, “NGL” - natural gas liquids and “Natural Gas” - shale gas and conventional natural gas.

	Three Months Ended March 31, 2024					**Three Months Ended March 31, 2023**				
	Heavy Crude Oil (bbl/d)	**Light and Medium Crude Oil (bbl/d)**	**NGL (bbl/d)**	**Natural Gas (Mcf/d)**	**Oil Equivalent (boe/d)**	**Heavy Crude Oil (bbl/d)**	**Light and Medium Crude Oil (bbl/d)**	**NGL (bbl/d)**	**Natural Gas (Mcf/d)**	**Oil Equivalent (boe/d)**
Canada – Heavy										
Peace River	9,481	9	48	10,088	11,219	10,783	13	54	11,264	12,727
Lloydminster	13,156	12	—	1,431	13,407	11,648	10	—	1,218	11,861
Peavine	17,599	—	—	—	17,599	11,760	—	—	—	11,760
Canada - Light										
Viking	—	9,181	190	11,068	11,215	—	14,640	193	11,620	16,770
Duvernay	—	1,803	1,757	5,456	4,469	—	1,063	944	2,623	2,444
Remaining Properties	324	488	636	16,337	4,171	—	672	684	22,395	5,089
United States										
Eagle Ford	—	54,543	16,668	103,973	88,540	—	15,280	5,338	32,946	26,109
Total	40,560	66,036	19,299	148,353	150,620	34,191	31,678	7,213	82,066	86,760

Baytex Energy Corp.

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

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

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

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

BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three months ended March 31, 2024 and 2023
Dated May 9, 2024

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three months ended March 31, 2024. This information is provided as of May 9, 2024. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three months ended March 31, 2024 ("Q1/2024") have been compared with the results for the three months ended March 31, 2023 ("Q1/2023"). This MD&A should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements ("consolidated financial statements") for the three months ended March 31, 2024, its audited comparative consolidated financial statements for the years ended December 31, 2023 and 2022, together with the accompanying notes, and its Annual Information Form ("AIF") for the year ended December 31, 2023. These documents and additional information about Baytex are accessible on the SEDAR+ website at www.sedarplus.ca and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

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

This MD&A contains forward-looking information and statements along with certain measures which do not have any standardized meaning in accordance with International Financial Reporting Standards ("IFRS") as prescribed by the International Accounting Standards Board. The terms "operating netback", "free cash flow", "average royalty rate", "heavy oil, net of blending and other expense" and "total sales, net of blending and other expense" are specified financial measures that do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. This MD&A also contains the terms "adjusted funds flow" and "net debt" which are capital management measures. Refer to our advisory on forward-looking information and statements and a summary of our specified financial measures at the end of the MD&A.

BAYTEX ENERGY CORP.

Baytex Energy Corp. is a North American focused oil and gas company based in Calgary, Alberta. The Company operates in Canada and the United States ("U.S."). The Canadian operating segment includes our light oil assets in the Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford operated and non-operated assets in Texas.

On June 20, 2023, Baytex and Ranger Oil Corporation ("Ranger") completed a 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 provided 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 increased 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 (which was fully repaid and cancelled in August 2023) and the net proceeds from the issuance of US$800 million senior unsecured notes due 2030.

FIRST QUARTER HIGHLIGHTS

Baytex delivered strong operating and financial results in Q1/2024. We invested $412.6 million on exploration and development expenditures and delivered production of 150,620 boe/d for Q1/2024 which reflects results from our development programs in the U.S. and Canada that are in line with expectations. The global crude oil market remained relatively balanced and benchmark prices were stable during Q1/2024 which resulted in adjusted funds flow(1) of $423.8 million.

Exploration and development expenditures totaled $412.6 million in Q1/2024 and were consistent with expectations. In the U.S. we invested $254.4 million during Q1/2024 and production averaged 88,540 boe/d which is higher than 26,109 boe/d for Q1/2023 due to the Merger with Ranger. We invested $158.1 million in Canada in Q1/2024 and generated production of 62,081 boe/d in Q1/2024 compared to 60,651 boe/d in Q1/2023 which reflects strong well performance from our light and heavy oil operations.

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

Oil prices in Q1/2024 were consistent with Q1/2023 as a result of modest global supply growth, continued OPEC production curtailments and stable demand which has resulted in a more balanced crude market. The WTI benchmark price for Q1/2024 was US$76.96US/bbl which was consistent with Q1/2023 when WTI averaged US$76.13/bbl. Adjusted funds flow(1) of $423.8 million and cash flows from operating activities of $383.8 million for Q1/2024 reflect increased production compared to Q1/2023 when we generated adjusted funds flow of $237.0 million and cash flows from operating activities of $184.9 million.

Net debt(1) of $2.6 billion at March 31, 2024 was slightly higher than $2.5 billion at December 31, 2023 which was primarily due to the impact of a weaker Canadian dollar at March 31, 2024 on our U.S. dollar denominated debt and also reflects $18.5 million of dividends and $34.7 million of land acquisitions completed during Q1/2024. We expect net debt to decline over the remainder of 2024 as we continue to allocate 50% of free cash flow to the balance sheet.

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

2024 GUIDANCE

The following table compares our 2024 annual guidance to our Q1/2024 results. Our 2024 annual guidance is unchanged with production guidance range of 150,000 to 156,000 boe/d and exploration and development expenditures of $1.2-$1.3 billion.

	2024 Annual Guidance (1)	Q1/2024 Results
Exploration and development expenditures	$1.2 - $1.3 billion	$412.6 million
Production (boe/d)	150,000 - 156,000	150,620
Expenses:		
Average royalty rate (2)	23%	22.7%
Operating (3)	$11.25 - $12.00/boe	$12.65/boe
Transportation (3)	$2.35 - $2.55/boe	$2.18/boe
General and administrative (3)	$92 million ($1.65/boe)	$22.4 million ($1.64/boe)
Cash Interest (3)	$190 million ($3.40/boe)	$53.3 million ($3.89/boe)
Current Income Taxes (4)	$40 million ($0.72/boe)	$1.7 million ($0.12/boe)
Leasing expenditures	$12 million	$4.9 million
Asset retirement obligations	$30 million	$6.5 million

(1) As announced on December 6, 2023.
(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) 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.
(4) 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.

RESULTS OF OPERATIONS

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

Production

	Three Months Ended March 31					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**11,493**	**54,543**	**66,036**	16,398	15,280	31,678
Heavy oil	**40,560**	**—**	**40,560**	34,191	—	34,191
Natural Gas Liquids (NGL)	**2,631**	**16,668**	**19,299**	1,875	5,338	7,213
Total liquids (bbl/d)	**54,684**	**71,211**	**125,895**	52,464	20,618	73,082
Natural gas (mcf/d)	**44,380**	**103,973**	**148,353**	49,120	32,946	82,066
Total production (boe/d)	**62,081**	**88,540**	**150,620**	60,651	26,109	86,760
Production Mix						
Segment as a percent of total	**41 %**	**59 %**	**100 %**	70 %	30 %	100 %
Light oil and condensate	**19 %**	**62 %**	**44 %**	27 %	59 %	37 %
Heavy oil	**65 %**	**— %**	**27 %**	56 %	— %	39 %
NGL	**4 %**	**19 %**	**13 %**	3 %	20 %	8 %
Natural gas	**12 %**	**19 %**	**16 %**	14 %	21 %	16 %

Production was 150,620 boe/d for Q1/2024 compared to 86,760 boe/d for Q1/2023. Total production was higher in Q1/2024 compared to Q1/2023 primarily due to production from the Eagle Ford properties acquired from Ranger along with our successful development program in Canada.

In Canada, production was 62,081 boe/d for Q1/2024 compared to 60,651 boe/d for Q1/2023. Our successful development program and strong well performance resulted in a 1,430 boe/d increase in production for Q1/2024 relative to Q1/2023. Strong production results from our Clearwater development resulted in Q1/2024 production of 17,599 boe/d at Peavine compared to 11,760 boe/d in Q1/2023. Higher production at Peavine was partially offset by the disposition of non-core light oil Viking assets in December 2023 that produced approximately 4,800 boe/d for Q1/2023.

In the U.S., production was 88,540 boe/d for Q1/2024 compared to 26,109 boe/d for Q1/2023. Production from the Merger was the primary factor that resulted in a 62,431 boe/d increase in production for Q1/2024 compared to Q1/2023. Production from the acquired Eagle Ford assets is primarily operated and is weighted towards light oil which resulted in a higher proportion of our total production being light oil in Q1/2024.

Total production of 150,620 boe/d for Q1/2024 is consistent with expectations and is at the lower end of our annual guidance of 150,000 - 156,000 boe/d which reflects production growth over the remainder of 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 pricing for crude oil was consistent between Q1/2024 and Q1/2023 as global supply and demand for crude oil remained relatively balanced. The WTI benchmark price averaged US$76.96/bbl for Q1/2024 compared to US$76.13/bbl for Q1/2023.

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$78.95/bbl during Q1/2024, representing a premium of US$1.99/bbl relative to WTI, compared to US$77.42/bbl or a premium of US$1.29/bbl for Q1/2023. The MEH benchmark traded at a higher premium to WTI in Q1/2024 compared to Q1/2023 mainly due to 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 from period to period 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 $92.16/bbl during Q1/2024 compared to $99.04/bbl during Q1/2023. Edmonton par traded at a discount to WTI of US$8.63/bbl for Q1/2024 compared to a discount of US$2.88/bbl for Q1/2023 due to higher production in the Western Canadian Sedimentary Basin.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS benchmark for Q1/2024 averaged $77.73/bbl compared to $69.44/bbl for the same period of 2023. The WCS heavy oil differential was US$19.33/bbl in Q1/2024 compared to US$24.77/bbl for Q1/2023 which was impacted by refinery turnarounds and reduced demand for Canadian heavy oil.

Natural Gas

Mild winter weather resulted in weak demand for North American natural gas and resulted in elevated inventory levels along with lower prices in Q1/2024 compared to Q1/2023.

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 that averaged US$2.24/mmbtu for Q1/2024 compared to US$3.42/mmbtu for Q1/2023 which reflects weak winter demand and elevated inventories in Q1/2024.

In Canada, we receive natural gas pricing based on the AECO benchmark which trades at a discount to NYMEX as a result of limited market access for Canadian natural gas production. The AECO benchmark averaged $2.05/mcf during Q1/2024 which is lower than $4.34/mcf for Q1/2023 due to mild winter weather and higher production in both the U.S. and Canada.

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

	Three Months Ended March 31		
	2024	2023	Change
Benchmark Averages			
WTI oil (US$/bbl) [(1)]	**76.96**	76.13	0.83
MEH oil (US$/bbl) [(2)]	**78.95**	77.42	1.53
MEH oil differential to WTI (US$/bbl)	**1.99**	1.29	0.70
Edmonton par oil ($/bbl) [(3)]	**92.16**	99.04	(6.88)
Edmonton par oil differential to WTI (US$/bbl)	**(8.63)**	(2.88)	(5.75)
WCS heavy oil ($/bbl) [(4)]	**77.73**	69.44	8.29
WCS heavy oil differential to WTI (US$/bbl)	**(19.33)**	(24.77)	5.44
AECO natural gas ($/mcf) [(5)]	**2.05**	4.34	(2.29)
NYMEX natural gas (US$/mmbtu) [(6)]	**2.24**	3.42	(1.18)
CAD/USD average exchange rate	**1.3488**	1.3520	(0.0032)

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

	Three Months Ended March 31					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) [1]	**$ 91.05**	**$ 101.93**	**$ 100.03**	$ 99.23	$ 103.27	$ 101.18
Heavy oil, net of blending and other expense ($/bbl) [2]	**65.22**	**—**	**65.22**	51.15	—	51.15
NGL ($/bbl) [1]	**26.60**	**26.08**	**26.15**	35.90	32.83	33.63
Natural gas ($/mcf) [1]	**2.42**	**2.37**	**2.39**	3.53	4.02	3.73
Total sales, net of blending and other expense ($/boe) [2]	**$ 62.33**	**$ 70.48**	**$ 67.12**	$ 59.71	$ 72.22	$ 63.48

(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[1] was $67.12/boe for Q1/2024 compared to $63.48/boe for Q1/2023. In Canada, our realized price of $62.33/boe for Q1/2024 was $2.62/boe higher than $59.71/boe for Q1/2023. Our realized price in the U.S. was $70.48/boe in Q1/2024 which is $1.74/boe lower than $72.22/boe in Q1/2023. The increase in our realized price in Canada for Q1/2024 was primarily a result of higher WCS benchmark pricing and higher heavy oil production compared to Q1/2023. The decrease in our realized price in the U.S. was primarily a result of contracts in place for our operated Eagle Ford production during Q1/2024.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price[2] was $91.05/bbl for Q1/2024 compared to $99.23/bbl for Q1/2023. Our realized light oil and condensate price for Q1/2024 decreased with the decline in the benchmark price and represents a discount to the Edmonton par price of $1.11/bbl for Q1/2024 compared to a premium of $0.19/bbl in Q1/2023. We realized a discount to the Edmonton par price in Q1/2024 as a higher proportion of our light oil production is from our Duvernay assets which have a lower light oil price realization relative to our Viking assets.

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 $101.93/bbl for Q1/2024 compared to $103.27/bbl for Q1/2023. Expressed in U.S. dollars, our realized light oil and condensate price of US$75.57/bbl for Q1/2024 represents a discount to MEH of US$3.38/bbl for Q1/2024, compared to a discount of US$1.04/bbl for Q1/2023. The discount of US$3.38/bbl for Q1/2024 was primarily a result of contracts in place for our operated Eagle Ford production during Q1/2024.

Our realized heavy oil price, net of blending and other expense[1] was $65.22/bbl in Q1/2024 compared to $51.15/bbl in Q1/2023. This was $14.07/bbl higher than Q1/2023, compared to a $8.29/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 sales of the blended product based on the WCS benchmark in Q1/2024 compared to Q1/2023.

Our realized NGL price[2] as a percentage of WTI varies based on the product mix of our NGL volumes and changes in the market prices for the underlying products. Our realized NGL price was $26.15/bbl in Q1/2024 or 25% of WTI (expressed in Canadian dollars) compared to $33.63/bbl or 33% of WTI (expressed in Canadian dollars) in Q1/2023. Our realized NGL price was lower as a percentage of WTI in Q1/2024 primarily due to lower demand for NGL products relative to Q1/2023.

We compare our realized natural gas price in the U.S. to the NYMEX benchmark and to the AECO benchmark price in Canada. In the U.S., our realized natural gas price[2] was US$1.76/mcf for Q1/2024 compared to US$2.97/mcf for Q1/2023 which is primarily the result of the decrease in the NYMEX benchmark over the same period. In Canada our realized natural gas price was $2.42/mcf for Q1/2024 compared to $3.53/mcf in Q1/2023. The decrease in our realized price for Q1/2024 relative to Q1/2023 was less than the AECO benchmark as a greater proportion of our sales were based on the daily AECO index which was higher than the monthly AECO index for Q1/2024.

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.

PETROLEUM AND NATURAL GAS SALES

	Three Months Ended March 31					
	2024			2023		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 95,221**	**$ 505,894**	**$ 601,115**	$ 146,456	$ 142,011	$ 288,467
Heavy oil	**304,924**	**—**	**304,924**	217,085	—	217,085
NGL	**6,368**	**39,562**	**45,930**	6,059	15,774	21,833
Total oil sales	**406,513**	**545,456**	**951,969**	369,600	157,785	527,385
Natural gas sales	**9,800**	**22,423**	**32,223**	16,022	11,929	27,951
Total petroleum and natural gas sales	**416,313**	**567,879**	**984,192**	385,622	169,714	555,336
Blending and other expense	**(64,208)**	**—**	**(64,208)**	(59,681)	—	(59,681)
Total sales, net of blending and other expense (1)	**$ 352,105**	**$ 567,879**	**$ 919,984**	$ 325,941	$ 169,714	$ 495,655

(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 $920.0 million for Q1/2024 increased $424.3 million from $495.7 million reported for Q1/2023. The increase in total sales is primarily the result of the Merger with Ranger along with higher production from our successful development programs.

In Canada, total sales, net of blending and other expense, of $352.1 million for Q1/2024 increased $26.2 million from $325.9 million reported for Q1/2023. The increase was primarily a result of higher realized pricing for Q1/2024 relative to Q1/2023 which resulted in a $14.8 million increase in total sales, net of blending and other expense. Higher production for Q1/2024 contributed to a $11.4 million increase in total sales, net of blending and other expense, relative to Q1/2023.

In the U.S., total petroleum and natural gas sales of $567.9 million for Q1/2024 increased $398.2 million from $169.7 million reported for Q1/2023. Total petroleum and natural gas sales increased $412.2 million from higher production in Q1/2024 relative to Q1/2023 as a result of the Merger with Ranger. The impact of increased production was partially offset by a $14.0 million decrease due to lower realized pricing compared to Q1/2023.

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 for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three months ended March 31, 2024 and 2023.

	Three Months Ended March 31					
	2024			2023		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 56,564**	**$ 152,607**	**$ 209,171**	$ 43,855	$ 49,398	$ 93,253
Average royalty rate (1)(2)	**16.1 %**	**26.9 %**	**22.7 %**	13.5 %	29.1 %	18.8 %
Royalties per boe (3)	**$ 10.01**	**$ 18.94**	**$ 15.26**	$ 8.03	$ 21.02	$ 11.94

(1) Average royalty rate is calculated as royalties divided by total sales, net of blending and other expense.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Royalties per boe is calculated as royalties divided by barrels of oil equivalent production volume for the applicable period.

Royalties for Q1/2024 were $209.2 million or 22.7% of total sales, net of blending and other expense, compared to $93.3 million or 18.8% for Q1/2023. Total royalty expense and our average royalty rate were higher in Q1/2024 relative to Q1/2023 due to the Merger with Ranger which resulted in higher total sales, net of blending and other expense, along with a higher proportion of our production being from the Eagle Ford which has a higher royalty rate than our Canadian properties.

Our average royalty rate[1] in Canada of 16.1% for Q1/2024 was higher than 13.5% for Q1/2023 as a result of heavy oil production growth. In the U.S., royalties averaged 26.9% of total sales for Q1/2024, which is lower than 29.1% for Q1/2023 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 22.7% for Q1/2024 is consistent with our annual guidance of 23% for 2024.

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

OPERATING EXPENSE

	Three Months Ended March 31					
	2024			2023		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 85,403**	**$ 88,032**	**$ 173,435**	$ 91,180	$ 21,228	$ 112,408
Operating expense per boe [1]	**$ 15.12**	**$ 10.93**	**$ 12.65**	$ 16.70	$ 9.03	$ 14.40

(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 $173.4 million ($12.65/boe) for Q1/2024 compared to $112.4 million ($14.40/boe) for Q1/2023. Total operating expense for Q1/2024 increased relative to Q1/2023 due to higher production while lower per unit operating costs reflect the lower per boe operating expense on the properties acquired from Ranger.

In Canada, total operating expense was $85.4 million ($15.12/boe) for Q1/2024 which was lower than $91.2 million ($16.70/boe) for Q1/2023. The decrease in total and per unit operating expense for Q1/2024 reflects production growth at Peavine along with the disposition of non-core Viking assets in Q4/2023.

In the U.S., operating expense was $88.0 million ($10.93/boe) for Q1/2024 compared to $21.2 million ($9.03/boe) for Q1/2023. Per boe operating expense in the U.S., expressed in U.S. dollars, was US$8.10/boe for Q1/2024 compared to US$6.68/boe for Q1/2023. The increase in total and per unit operating expense in Q1/2024 reflects the additional production from the properties acquired from Ranger along with higher workover and maintenance costs on our non-operated acreage.

Operating expense of $12.65/boe for Q1/2024 is consistent with expectations and our annual guidance range of $11.25 - $12.00/boe for 2024 reflects production growth over the remainder of the year.

TRANSPORTATION EXPENSE

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

The following table compares our transportation expense for the three months ended March 31, 2024 and 2023.

	Three Months Ended March 31					
	2024			2023		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 18,210**	**$ 11,625**	**$ 29,835**	$ 17,005	$ —	$ 17,005
Transportation expense per boe [1]	**$ 3.22**	**$ 1.44**	**$ 2.18**	$ 3.12	$ —	$ 2.18

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

Transportation expense was $29.8 million ($2.18/boe) for Q1/2024 compared to $17.0 million ($2.18/boe) for Q1/2023. In Canada, total transportation expense and per unit costs were higher in Q1/2024 as a result of additional heavy oil production relative to Q1/2023. In the U.S., transportation expense of $11.6 million consists of trucking and pipeline costs on our operated Eagle Ford operations acquired from Ranger.

Per unit transportation expense of $2.18/boe for Q1/2024 is consistent with expectations and is slightly below our annual guidance range of $2.35 - $2.55/boe for 2024.

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 $64.2 million for Q1/2024 compared to $59.7 million for Q1/2023. Higher blending and other expense is primarily a result of higher heavy oil production and pipeline shipments in Q1/2024 relative to Q1/2023.

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 executed. The following table summarizes the results of our financial derivative contracts for the three months ended March 31, 2024 and 2023.

	Three Months Ended March 31		
($ thousands)	**2024**	2023	Change
Realized financial derivatives gain			
Crude oil	**$ 946**	$ 5,415	$ (4,469)
Natural gas	**4,542**	—	4,542
Total	**$ 5,488**	$ 5,415	$ 73
Unrealized financial derivatives (loss) gain			
Crude oil	**$ (31,465)**	$ 9,210	$ (40,675)
Natural gas	**(885)**	—	(885)
Total	**$ (32,350)**	$ 9,210	$ (41,560)
Total financial derivatives (loss) gain			
Crude oil	**$ (30,519)**	$ 14,625	$ (45,144)
Natural gas	**3,657**	—	3,657
Total	**$ (26,862)**	$ 14,625	$ (41,487)

We recorded a total financial derivative loss of $26.9 million for Q1/2024 compared to a gain of $14.6 million for Q1/2023. The realized financial derivatives gain of $5.5 million for Q1/2024 was primarily a result of the market prices for natural gas settling at levels below those set in our derivative contracts. The unrealized financial derivatives loss of $32.4 million for Q1/2024 is primarily due to changes in forecasted crude oil pricing used to revalue the volumes outstanding on our crude oil and natural gas contracts in place at March 31, 2024 relative to December 31, 2023. The fair value of our financial derivative contracts resulted in a net liability of $9.1 million at March 31, 2024 compared to a net asset of $23.3 million at December 31, 2023.

As at May 9, 2024 we had the following commodity financial derivative contracts for the period subsequent to March 31, 2024.

	Remaining Period	Volume	Price/Unit [1]	Index
Oil				
Basis differential	Apr 2024 to Jun 2024	4,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.10/bbl	WCS
Basis differential	July 2024 to Dec 2024	9,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.34/bbl	WCS
Basis differential	Apr 2024 to Dec 2024	3,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.27/bbl	WCS
Basis differential [2]	July 2024 to Dec 2024	3,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.25/bbl	WCS
Basis differential	July 2024 to Dec 2024	6,000 bbl/d	WTI less US$13.58/bbl	WCS
Basis differential	Apr 2024 to Dec 2024	2,750 bbl/d	WTI less US$2.94/bbl	MSW
Basis differential	July 2024 to Dec 2024	3,500 bbl/d	WTI less US$2.78/bbl	MSW
Basis differential [2]	Jan 2025 to Dec 2025	2,000 bbl/d	WTI less US$2.75/bbl	MSW
Collar	Apr 2024 to Jun 2024	35,250 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	10,000 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Sep 2024	10,000 bbl/d	US$60.00/US$100.00	WTI
Collar	Oct 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$94.15	WTI
Collar	July 2024 to Dec 2024	1,500 bbl/d	US$60.00/US$90.35	WTI
Collar	July 2024 to Dec 2024	1,000 bbl/d	US$60.00/US$90.00	WTI
Collar	July 2024 to Dec 2024	2,000 bbl/d	US$60.00/US$85.00	WTI
Collar	July 2024 to Dec 2024	2,000 bbl/d	US$60.00/US$84.60	WTI
Collar	July 2024 to Dec 2024	5,000 bbl/d	US$60.00/US$84.15	WTI
Collar	Oct 2024 to Dec 2024	3,500 bbl/d	US$60.00/US$87.10	WTI
Collar	Oct 2024 to Dec 2024	3,500 bbl/d	US$60.00/US$85.75	WTI
Collar	Jan 2025 to Mar 2025	5,000 bbl/d	US$60.00/US$88.70	WTI
Collar [2]	Jan 2025 to Mar 2025	2,500 bbl/d	US$60.00/US$90.20	WTI
Collar [2]	Jan 2025 to Mar 2025	2,500 bbl/d	US$60.00/US$90.05	WTI
Collar [2]	Jan 2025 to Mar 2025	2,500 bbl/d	US$60.00/US$90.00	WTI
Collar [2]	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$94.25	WTI
Collar [2]	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$93.90	WTI
Collar [2]	Jan 2025 to Jun 2025	5,000 bbl/d	US$60.00/US$91.95	WTI
Collar [2]	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$90.00	WTI
Natural Gas				
Collar	Apr 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.19	NYMEX
Collar	Apr 2024 to Dec 2024	8,500 mmbtu/d	US$3.00/US$4.15	NYMEX
Collar	Apr 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.10	NYMEX
Collar	Apr 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.09	NYMEX
Collar	Apr 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.06	NYMEX
Collar	Apr 2024 to Jun 2024	11,538 mmbtu/d	US$2.33/US$3.00	NYMEX
Collar	Jan 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.01	NYMEX
Collar [2]	Jan 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.32	NYMEX

(1) Based on the weighted average price per unit for the period.
(2) Contract entered subsequent to March 31, 2024.

OPERATING NETBACK

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

	Three Months Ended March 31					
	2024			2023		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**62,081**	**88,540**	**150,620**	60,651	26,109	86,760
Operating netback:						
Total sales, net of blending and other expense [(1)]	**$ 62.33**	**$ 70.48**	**$ 67.12**	$ 59.71	$ 72.22	$ 63.48
Less:						
Royalties [(2)]	**(10.01)**	**(18.94)**	**(15.26)**	(8.03)	(21.02)	(11.94)
Operating expense [(2)]	**(15.12)**	**(10.93)**	**(12.65)**	(16.70)	(9.03)	(14.40)
Transportation expense [(2)]	**(3.22)**	**(1.44)**	**(2.18)**	(3.12)	—	(2.18)
Operating netback [(1)]	**$ 33.98**	**$ 39.17**	**$ 37.03**	$ 31.86	$ 42.17	$ 34.96
Realized financial derivatives gain [(3)]	**—**	**—**	**0.40**	—	—	0.69
Operating netback after financial derivatives [(1)]	**$ 33.98**	**$ 39.17**	**$ 37.43**	$ 31.86	$ 42.17	$ 35.65

(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.

Total operating netback of $37.03/boe for Q1/2024 was higher than $34.96/boe for Q1/2023 due to the increase in our realized price which resulted in higher per unit sales net of royalties during Q1/2024 relative to Q1/2023. A higher proportion of our production was from our U.S. properties in Q1/2024 which have lower operating and transportation expense which resulted in total operating and transportation expense of $14.83/boe for Q1/2024 that was lower than $16.58/boe for Q1/2023. Our operating netback net of realized gains and losses on financial derivatives was $37.43/boe for Q1/2024 compared to $35.65/boe for Q1/2023.

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 three months ended March 31, 2024 and 2023.

	Three Months Ended March 31		
($ thousands except for per boe)	**2024**	2023	Change
Gross general and administrative expense	**$ 28,763**	$ 14,416	$ 14,347
Overhead recoveries	**(6,351)**	(2,682)	(3,669)
General and administrative expense	**$ 22,412**	$ 11,734	$ 10,678
General and administrative expense per boe [(1)]	**$ 1.64**	$ 1.50	$ 0.14

(1) General and administrative expense per boe is calculated as general and administrative expense divided by barrels of oil equivalent production volume for the applicable period.

G&A expense was $22.4 million ($1.64/boe) for Q1/2024 compared to $11.7 million ($1.50/boe) for Q1/2023. G&A expense was $10.7 million higher relative to Q1/2023 which reflects the staffing costs associated with the personnel retained following the Merger with Ranger. G&A expense of $1.64/boe for Q1/2024 is consistent with our 2024 annual guidance of $1.65/boe.

FINANCING AND INTEREST EXPENSE

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

The following table summarizes our financing and interest expense for the three months ended March 31, 2024 and 2023.

	Three Months Ended March 31		
($ thousands except for per boe)	**2024**	2023	Change
Interest on credit facilities	**$ 18,289**	$ 6,216	$ 12,073
Interest on long-term notes	**34,678**	12,094	22,584
Interest on lease obligations	**313**	65	248
Cash interest	**$ 53,280**	$ 18,375	$ 34,905
Accretion of debt issue costs	**3,060**	524	2,536
Accretion of asset retirement obligations	**4,927**	4,826	101
Financing and interest expense	**$ 61,267**	$ 23,725	$ 37,542
Cash interest per boe (1)	**$ 3.89**	$ 2.35	$ 1.54
Financing and interest expense per boe (1)	**$ 4.47**	$ 3.04	$ 1.43

(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 $61.3 million ($4.47/boe) for Q1/2024 compared to $23.7 million ($3.04/boe) for Q1/2023. Higher interest costs in Q1/2024 compared to Q1/2023 are primarily the result of the additional debt outstanding after the Merger with Ranger.

Cash interest of $53.3 million ($3.89/boe) for Q1/2024 was higher than $18.4 million ($2.35/boe) for Q1/2023 and is primarily a result of higher debt balances outstanding after the Merger, which included the issuance of US$800.0 million aggregate principal amount of long-term notes. Interest on our credit facilities increased in Q1/2024 relative to Q1/2023 due to higher applicable borrowing rates along with additional principal amounts outstanding following the Merger. The weighted average interest rate applicable on our credit facilities was 8.1% for Q1/2024 compared to 6.0% for Q1/2023.

Accretion of asset retirement obligations of $4.9 million for Q1/2024 was consistent with $4.8 million for Q1/2023. Accretion of debt issue costs was higher for Q1/2024 compared to Q1/2023 due to the increase in debt issue costs associated with the increased credit facilities and new long-term notes issued to fund the Merger with Ranger.

Cash interest expense of $3.89/boe for Q1/2024 is higher than our 2024 annual guidance of $3.40/boe which is consistent with expectations as we expect to reduce debt and increase production throughout the remainder of 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 $18.0 thousand for Q1/2024 compared to $163.0 thousand for Q1/2023.

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 three months ended March 31, 2024 and 2023.

	Three Months Ended March 31		
($ thousands except for per boe)	**2024**	2023	Change
Depletion	**$ 341,435**	$ 164,435	$ 177,000
Depreciation	**2,702**	1,564	1,138
Depletion and depreciation	**$ 344,137**	$ 165,999	$ 178,138
Depletion and depreciation per boe (1)	**$ 25.11**	$ 21.26	$ 3.85

(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 $344.1 million ($25.11/boe) for Q1/2024 compared to $166.0 million ($21.26/boe) for Q1/2023. Total depletion and depreciation expense and depletion and depreciation per boe were higher in Q1/2024 relative to Q1/2023 due to 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 that was recorded at December 31, 2023.

IMPAIRMENT

We did not identify indicators of impairment or impairment reversal for any of our cash generating units ("CGUs") at March 31, 2024.

2023 Impairment

At December 31, 2023, we identified indicators of impairment for oil and gas properties in our legacy non-operated Eagle Ford CGU due to changes in our reserves and in our Viking CGU due to changes in our reserves and a loss recorded on a disposition of an asset. We recorded an impairment loss of $833.7 million.

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 $9.5 million for Q1/2024 which is consistent with $9.8 million for Q1/2023.

FOREIGN EXCHANGE

Unrealized foreign exchange gains and losses are primarily a result of changes in the reported amount of our U.S. dollar denominated long-term notes and credit facilities in our Canadian functional currency entities. The long-term notes and credit facilities are translated to Canadian dollars on the balance sheet date using the closing CAD/USD exchange rate resulting in unrealized gains and losses. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in our Canadian functional currency entities.

	Three Months Ended March 31		
($ thousands except for exchange rates)	**2024**	2023	Change
Unrealized foreign exchange loss (gain)	**$ 38,718**	$ (213)	$ 38,931
Realized foreign exchange loss	**1,219**	150	1,069
Foreign exchange loss (gain)	**$ 39,937**	$ (63)	$ 40,000
CAD/USD exchange rates:			
At beginning of period	**1.3205**	1.3534	
At end of period	**1.3533**	1.3528	

We recorded a foreign exchange loss of $39.9 million for Q1/2024 compared to a gain of $0.1 million for Q1/2023.

The unrealized foreign exchange loss of $38.7 million for Q1/2024 is due to changes in the reported amount of our long-term notes and credit facilities. The $38.7 million loss recorded in Q1/2024 is the result of a weak Canadian dollar relative to the U.S. dollar at March 31, 2024 compared to December 31, 2023. The unrealized foreign exchange gain of $0.2 million for Q1/2023 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 March 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 functional currency entities. We recorded a realized foreign exchange loss of $1.2 million for Q1/2024 compared to $0.2 million for Q1/2023.

INCOME TAXES

	Three Months Ended March 31		
($ thousands)	**2024**	2023	Change
Current income tax expense	**$ 1,680**	$ 1,120	$ 560
Deferred income tax expense	**15,801**	15,523	278
Total income tax expense	**$ 17,481**	$ 16,643	$ 838

Current income tax expense was $1.7 million for Q1/2024 compared to $1.1 million for Q1/2023.

We recorded deferred tax expense of $15.8 million for Q1/2024 compared to $15.5 million for Q1/2023. The deferred tax expense recorded in Q1/2024 reflects income generated on our U.S. operations for the period as the tax pools associated with our Canadian operations are subject to a valuation allowance. The deferred tax expense recorded in Q1/2023 reflects the income generated by 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 of $244.8 million, late payment interest of $166.6 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 potentially penalties. The amount of cash taxes owing, late payment interest and potential penalties are dependent upon the taxpayer(s) ultimately liable (the trusts or their corporate beneficiary) and the amount of unused tax shelter available to the taxpayer(s) to offset the reassessed income, including tax shelter from subsequent years that may be carried back and applied to prior years.

NET INCOME AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income for the three months ended March 31, 2024 and 2023 are set forth in the following table.

	Three Months Ended March 31		
($ thousands)	**2024**	2023	Change
Petroleum and natural gas sales	**$ 984,192**	$ 555,336	$ 428,856
Royalties	**(209,171)**	(93,253)	(115,918)
Revenue, net of royalties	**775,021**	462,083	312,938
Expenses			
Operating	**(173,435)**	(112,408)	(61,027)
Transportation	**(29,835)**	(17,005)	(12,830)
Blending and other	**(64,208)**	(59,681)	(4,527)
Operating netback (1)	**$ 507,543**	$ 272,989	$ 234,554
General and administrative	**(22,412)**	(11,734)	(10,678)
Cash interest	**(53,280)**	(18,375)	(34,905)
Realized financial derivatives gain	**5,488**	5,415	73
Realized foreign exchange loss	**(1,219)**	(150)	(1,069)
Other expense	**(1,071)**	(213)	(858)
Current income tax expense	**(1,680)**	(1,120)	(560)
Cash share-based compensation	**(9,523)**	(9,823)	300
Adjusted funds flow (2)	**$ 423,846**	$ 236,989	$ 186,857
Transaction costs	**(1,539)**	(8,871)	7,332
Exploration and evaluation	**(18)**	(163)	145
Depletion and depreciation	**(344,137)**	(165,999)	(178,138)
Non-cash financing and interest	**(7,987)**	(5,350)	(2,637)
Non-cash other income	**—**	1,271	(1,271)
Unrealized financial derivatives (loss) gain	**(32,350)**	9,210	(41,560)
Unrealized foreign exchange (loss) gain	**(38,718)**	213	(38,931)
Gain (loss) on dispositions	**2,661**	(336)	2,997
Deferred income tax expense	**(15,801)**	(15,523)	(278)
Net (loss) income	**$ (14,043)**	$ 51,441	$ (65,484)

(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 $423.8 million for Q1/2024 compared to $237.0 million for Q1/2023. The $186.9 million increase in adjusted funds flow was primarily due to higher production from the Merger with Ranger, partially offset by higher general and administrative and cash interest costs. We reported a net loss of $14.0 million for Q1/2024 compared to net income of $51.4 million for Q1/2023. The decrease in net income for Q1/2024 relative to Q1/2023 is the result of a higher depletion rate and associated depreciation expense, as well as unrealized losses on financial derivatives and an unrealized foreign exchange loss.

OTHER COMPREHENSIVE INCOME

Other comprehensive income is comprised of the foreign currency translation adjustment on U.S. net assets which is not recognized in net income or loss. The foreign currency translation gain of $110.6 million for Q1/2024 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 March 31, 2024 compared to December 31, 2023. The CAD/USD exchange rate was 1.3533 CAD/USD as at March 31, 2024 compared to 1.3205 CAD/USD at December 31, 2023.

CAPITAL EXPENDITURES

Capital expenditures for the three months ended March 31, 2024 and 2023 are summarized as follows.

	Three Months Ended March 31					
	2024			2023		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 126,007**	**$ 219,939**	**$ 345,946**	$ 154,953	$ 48,836	$ 203,789
Facilities and other	**32,119**	**34,486**	**66,605**	29,653	184	29,837
Exploration and development expenditures	**$ 158,126**	**$ 254,425**	**$ 412,551**	$ 184,606	$ 49,020	$ 233,626
Property acquisitions	**$ 34,275**	**$ 1,128**	**$ 35,403**	$ 506	$ —	$ 506
Proceeds from dispositions	**$ (25)**	**$ —**	**$ (25)**	$ (235)	$ —	$ (235)

Exploration and development expenditures were $412.6 million for Q1/2024 compared to $233.6 million for Q1/2023. Exploration and development expenditures in Q1/2024 were higher compared to Q1/2023 as a result of development activity on the properties acquired from Ranger. We also completed property acquisitions, including the acquisition of 30.75 net sections of high-quality Duvernay lands adjacent to our existing acreage, in Q1/2024 for a total of $35.4 million.

In Canada, exploration and development expenditures were $158.1 million in Q1/2024 compared to $184.6 million in Q1/2023. Lower drilling and completion spending of $126.0 million in Q1/2024 relative to Q1/2023 when we spent $155.0 million was primarily the result of the disposition of non-core light oil Viking properties. We also invested $32.1 million on facilities and other expenditures during Q1/2024.

Total U.S. exploration and development expenditures were $254.4 million for Q1/2024 compared to $49.0 million in Q1/2023. The increase in exploration and development expenditures for Q1/2024 is due to development activity on our properties acquired from Ranger.

Exploration and development expenditures of $412.6 million for Q1/2024 were consistent with expectation. Our annual guidance of $1.2 - $1.3 billion reflects moderated activity levels over the remainder of 2024.

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain a strong balance sheet that provides financial flexibility to execute our development programs, provide returns to shareholders and optimize our portfolio through strategic acquisitions. We strive to actively manage our capital structure in response to changes in economic conditions. At March 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. At March 31, 2024, net debt[1] of $2.6 billion was consistent with $2.5 billion at December 31, 2023 and reflects the timing of exploration and development expenditures, minor property acquisitions, along with the effect of a weaker Canadian dollar relative to the U.S. dollar at March 31, 2024 compared to December 31, 2023.

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

Credit Facilities

At March 31, 2024, we had $849.9 million of principal amount outstanding under our revolving credit facilities which total US$1.1 billion ($1.5 billion) (the "Credit Facilities"). The Credit Facilities are secured and are comprised of a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex and a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. On May 9, 2024, we extended the maturity of 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. As a result of the amendment, borrowing in Canadian funds currently based on the banker's acceptance rate will be 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 Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance discount rates or secured overnight financing rates ("SOFR"), plus applicable margins.
The weighted average interest rate on the Credit Facilities was 8.1% for Q1/2024 compared to 6.0% for Q1/2023. The interest rate on our Credit Facilities has increased due to an increase in the margins applicable to our Credit Facilities in addition to higher underlying benchmark rates in 2024 relative to the same period in 2023.

At March 31, 2024, we had $5.7 million of outstanding letters of credit, $4.3 million of which is under a $20 million uncommitted unsecured demand revolving letter of credit facility (December 31, 2023 - $5.6 million outstanding). Letters of credit under this facility are guaranteed by Export Development Canada and do not use capacity available under the Credit Facilities.

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

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at March 31, 2024.

Covenant Description	Position as at March 31, 2024	Covenant
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0.4:1.0**	3.5:1.0
Interest Coverage (3) (Minimum Ratio)	**10.3:1.0**	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 March 31, 2024, the Company's Senior Secured Debt totaled $849.9 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 March 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 expense, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expense for the twelve months ended March 31, 2024 was $211.3 million.

(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade payables, share-based compensation liability, dividends payable, asset retirement obligations, leases, deferred income tax liabilities, other long-term liabilities and financial derivative liabilities. As at March 31, 2024, the Company's Total Debt totaled $2.5 billion of principal amounts outstanding.

Long-Term Notes

At March 31, 2024 we have two issuances of long-term notes outstanding with a total principal amount of $1.6 billion. The long-term notes do not contain any financial maintenance covenants.

On February 5, 2020, we issued US$500 million aggregate principal amount of senior unsecured notes due April 1, 2027 bearing interest at a rate of 8.75% per annum payable semi-annually (the "8.75% Senior Notes"). The 8.75% Senior Notes are redeemable at our option, in whole or in part, at specified redemption prices after April 1, 2023 and will be redeemable at par from April 1, 2026 to maturity. At March 31, 2024 there was US$409.8 million aggregate principal amount of the 8.75% Senior Notes outstanding.

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 March 31, 2024 there was US$800.0 million aggregate principal amount of the 8.50% Senior Notes outstanding.

On April 1, 2024, we 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.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the three months ended March 31, 2024, we issued 0.3 million common shares pursuant to our share-based compensation program. As at March 31, 2024, we had 821.3 million common shares issued and outstanding and no preferred shares issued and outstanding.

Our shareholder returns framework includes common share repurchases and a quarterly dividend. During the three months ended March 31, 2024, we repurchased 0.6 million common shares under our normal course issuer bid ("NCIB") at an average price of $4.76 per share.

On January 2 and April 1, 2024, we paid a quarterly cash dividend of CDN$0.0225 per share to shareholders of record. On May 9, 2024, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on July 2, 2024 for shareholders on record as at June 14, 2024. These dividends are designated as "eligible dividends" for Canadian income tax purposes. For U.S. income tax purposes, Baytex's dividends are considered "qualified dividends."

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of March 31, 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
Financial derivatives	**14,510**	14,510	—	—	—
Credit facilities - principal	**849,926**	—	849,926	—	—
Long-term notes - principal [2]	**1,637,155**	—	—	554,555	1,082,600
Interest on long-term notes [1][2]	**705,645**	140,545	281,089	184,175	99,836
Lease obligations - principal	**33,829**	12,847	9,195	7,213	4,574
Processing agreements	**5,488**	588	965	3,935	—
Transportation agreements	**201,668**	53,546	92,629	45,655	9,838
Total	**$ 3,448,221**	$ 222,036	$ 1,233,804	$ 795,533	$ 1,196,848

(1) Excludes interest on our credit facilities as interest payments fluctuate based on a floating rate of interest and changes in the outstanding balances.
(2) Excludes principal and interest on the 7.375% Senior Notes that were issued on April 1, 2024.

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities when they reach the end of their economic lives. The present value of the future estimated abandonment and reclamation costs are included in the asset retirement obligations presented in the statement of financial position. Programs to abandon and reclaim well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

QUARTERLY FINANCIAL INFORMATION

	2024	2023				2022		
($ thousands, except per common share amounts)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Petroleum and natural gas sales	**984,192**	1,065,515	1,163,010	598,760	555,336	648,986	712,065	854,169
Net (loss) income	**(14,043)**	(625,830)	127,430	213,603	51,441	352,807	264,968	180,972
Per common share - basic	**(0.02)**	(0.75)	0.15	0.37	0.09	0.65	0.48	0.32
Per common share - diluted	**(0.02)**	(0.75)	0.15	0.36	0.09	0.64	0.47	0.32
Adjusted funds flow (1)	**423,846**	502,148	581,623	273,590	236,989	255,552	284,288	345,704
Per common share - basic	**0.52**	0.60	0.68	0.47	0.43	0.47	0.51	0.61
Per common share - diluted	**0.52**	0.60	0.68	0.47	0.43	0.46	0.51	0.60
Free cash flow (2)	**(88)**	290,785	158,440	96,313	(1,918)	143,324	111,568	245,316
Per common share - basic	**—**	0.35	0.19	0.17	—	0.26	0.20	0.43
Per common share - diluted	**—**	0.35	0.18	0.16	—	0.26	0.20	0.43
Cash flows from operating activities	**383,773**	474,452	444,033	192,308	184,938	303,441	310,423	360,034
Per common share - basic	**0.47**	0.57	0.52	0.33	0.34	0.56	0.56	0.63
Per common share - diluted	**0.47**	0.57	0.52	0.33	0.34	0.55	0.56	0.63
Dividends declared	**18,494**	18,381	19,138	—	—	—	—	—
Per common share – basic	**0.02**	0.02	0.02	—	—	—	—	—
Per common share – diluted	**0.02**	0.02	0.02	—	—	—	—	—
Exploration and development	**412,551**	199,214	409,191	170,704	233,626	103,634	167,453	96,633
Canada	**158,126**	75,137	107,053	96,403	184,606	85,641	117,150	51,881
U.S.	**254,425**	124,077	302,138	74,301	49,020	17,993	50,303	44,752
Property acquisitions	**35,403**	33,923	4,277	(62)	506	1,085	—	208
Proceeds from dispositions	**(25)**	(159,745)	(226)	(50)	(235)	(148)	(25,460)	(14)
Net debt (1)	**2,639,841**	2,534,287	2,824,348	2,814,844	995,170	987,446	1,113,559	1,123,297
Total assets	**7,717,495**	7,460,931	8,946,181	8,617,444	5,180,059	5,103,769	4,923,617	4,870,432
Common shares outstanding	**821,322**	821,681	845,360	862,192	545,553	544,930	547,615	560,139
Daily production								
Total production (boe/d)	**150,620**	160,373	150,600	89,761	86,760	86,864	83,194	83,090
Canada (boe/d)	**62,081**	64,744	63,289	55,874	60,651	56,946	55,803	54,919
U.S. (boe/d)	**88,540**	95,629	87,311	33,887	26,109	29,918	27,391	28,170
Benchmark prices								
WTI oil (US$/bbl)	**76.96**	78.32	82.26	73.78	76.13	82.64	91.56	108.41
WCS heavy oil ($/bbl)	**77.73**	76.86	93.02	78.85	69.44	77.37	93.62	122.05
Edmonton par oil ($/bbl)	**92.16**	99.72	107.93	95.13	99.04	109.57	116.79	137.79
CAD/USD avg exchange rate	**1.3488**	1.3619	1.3410	1.3431	1.3520	1.3577	1.3059	1.2766
AECO natural gas ($/mcf)	**2.05**	2.66	2.39	2.35	4.34	5.58	5.81	6.27
NYMEX natural gas (US$/mmbtu)	**2.24**	2.88	2.55	2.10	3.42	6.26	8.20	7.17
Total sales, net of blending and other expense ($/boe) (2)	**67.12**	68.00	80.34	66.82	63.48	74.93	87.68	105.44
Royalties ($/boe) (3)	**(15.26)**	(15.49)	(17.33)	(13.21)	(11.94)	(15.23)	(19.21)	(22.69)
Operating expense ($/boe) (3)	**(12.65)**	(11.17)	(12.57)	(14.62)	(14.40)	(13.06)	(14.39)	(14.21)
Transportation expense ($/boe) (3)	**(2.18)**	(2.02)	(2.02)	(1.78)	(2.18)	(1.85)	(1.67)	(1.56)
Operating netback ($/boe) (2)	**37.03**	39.32	48.42	37.21	34.96	44.79	52.41	66.98
Financial derivatives (loss) gain ($/boe) (3)	**0.40**	0.84	0.15	2.00	0.69	(6.21)	(9.98)	(16.41)
Operating netback after financial derivatives ($/boe) (2)	**37.43**	40.16	48.57	39.21	35.65	38.58	42.43	50.57

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

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

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

Our results for the previous eight quarters reflect the disciplined execution of our capital programs as oil and natural gas prices have fluctuated. Production steadily increased from 83,090 boe/d in Q2/2022 and reached 160,373 boe/d in Q4/2023 due to strong well performance from our development programs in Canada and the U.S., along with the production contribution from the Merger with Ranger. Production of 150,620 boe/d in Q1/2024 reflects the timing of our development programs along with asset dispositions.

Commodity prices strengthened to multi-year highs in 2022 following Russia's invasion of Ukraine which created elevated uncertainty surrounding the global supply of oil and natural gas and is reflected in our realized sales price of $105.44/boe for Q2/2022, which is our strongest realized pricing in the most recent eight quarters. Our realized price of $67.12/boe for Q1/2024 reflects recent stability in crude oil prices as global supply growth and stable demand has resulted in a more balanced market.

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 $423.8 million for Q1/2024 reflects strong production results from our development plans in the U.S. and Canada as well as the Merger with Ranger.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt(1) increased to $2.6 billion at Q1/2024 from $1.1 billion at Q2/2022 as a result of additional debt used to fund the Merger which closed in Q2/2023 along with $439.9 million of shareholder returns. The change in net debt also reflects free cash flow(2) of $1.0 billion generated over the last eight quarters.

(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, 2023 for a full description of the risks associated with these regulations and how they may impact our business in the future. In addition to the Risk Factors discussed in the AIF for the year ended December 31, 2023, additional information related to our emissions and sustainability initiatives is available on our website.

Reporting Regulations

Environmental reporting for public enterprises continues to evolve and the Company may be subject to additional future disclosure requirements. The International Sustainability Standards Board ("ISSB") has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Sustainability Standards Board has released proposed standards that are aligned with the ISSB release, but include suggestions for Canadian-specific modifications. The Canadian Securities Administrators 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 financial arrangements that are excluded from the consolidated financial statements as at March 31, 2024, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the three months ended March 31, 2024. Further information on our critical accounting policies and estimates can be found in the notes to the audited annual consolidated financial statements and MD&A for the year ended December 31, 2023.

CHANGES IN ACCOUNTING POLICIES

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.

In October 2022, the IASB issued *Non-current Liabilities with Covenants* which amended IAS 1 *Presentation of Financial Statements*. The amendments specify the classification and disclosure of a liability with covenants and is effective January 1, 2024.

These amendments have not had a material impact on our consolidated financial statements.

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	
($ thousands)	**March 31, 2024**	March 31, 2023
Petroleum and natural gas sales	**$ 984,192**	$ 555,336
Light oil and condensate [1]	**(601,115)**	(288,467)
NGL [1]	**(45,930)**	(21,833)
Natural gas sales [1]	**(32,223)**	(27,951)
Heavy oil sales	**$ 304,924**	$ 217,085
Blending and other expense [2]	**(64,208)**	(59,681)
Heavy oil, net of blending and other expense	**$ 240,716**	$ 157,404

(1) Component of petroleum and natural gas sales. See Note 13 - Petroleum and Natural Gas Sales in the consolidated financial statements for the three months ended March 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	
($ thousands)	**March 31, 2024**	March 31, 2023
Petroleum and natural gas sales	**$ 984,192**	$ 555,336
Blending and other expense	**(64,208)**	(59,681)
Total sales, net of blending and other expense	**$ 919,984**	$ 495,655
Royalties	**(209,171)**	(93,253)
Operating expense	**(173,435)**	(112,408)
Transportation expense	**(29,835)**	(17,005)
Operating netback	**$ 507,543**	$ 272,989
Realized financial derivatives gain [1]	**5,488**	5,415
Operating netback after realized financial derivatives	**$ 513,031**	$ 278,404

(1) Realized financial derivatives gain or loss is a component of financial derivatives gain or loss. See Note 17 - Financial Instruments and Risk Management in the consolidated financial statements for the three months ended March 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 and transaction costs.

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

	Three Months Ended	
($ thousands)	**March 31, 2024**	March 31, 2023
Cash flows from operating activities	**$ 383,773**	$ 184,938
Change in non-cash working capital	**32,023**	39,054
Additions to exploration and evaluation assets	**—**	(490)
Additions to oil and gas properties	**(412,551)**	(233,136)
Payments on lease obligations	**(4,872)**	(1,155)
Transaction costs	**1,539**	8,871
Free cash flow	**$ (88)**	$ (1,918)

Non-GAAP Financial Ratios

Heavy oil, net of blending and other expense per bbl

Heavy oil, net of blending and other expense per bbl represents the realized price for produced heavy oil volumes during a period. Heavy oil, net of blending and other expense is a non-GAAP measure that is divided by barrels of heavy oil production volume for the applicable period to calculate the ratio. We use heavy oil, net of blending and other expense per bbl to analyze our realized heavy oil price for produced volumes against the WCS benchmark price.

Total sales, net of blending and other expense per boe

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

Average royalty rate

Average royalty rate is used to evaluate the performance of our operations from period to period and is comprised of royalties divided by total sales, net of blending and other expense (a non-GAAP financial measure). The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction.

Operating netback per boe

Operating netback per boe is operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period and is used to assess our operating performance on a unit of production basis. Realized financial derivative gains and losses per boe are added to operating netback per boe to arrive at operating netback after financial derivatives per boe. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

Capital Management Measures

Net debt

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

The following table summarizes our calculation of net debt.

	As at	
($ thousands)	**March 31, 2024**	December 31, 2023
Credit facilities	**$ 835,363**	$ 848,749
Unamortized debt issuance costs - Credit facilities [(1)]	**14,563**	15,987
Long-term notes	**1,602,417**	1,562,361
Unamortized debt issuance costs - Long-term notes [(1)]	**34,738**	35,114
Trade payables	**626,137**	477,295
Share-based compensation liability	**18,667**	35,732
Dividends payable	**18,494**	18,381
Other long-term liabilities	**19,622**	19,147
Cash	**(29,140)**	(55,815)
Trade receivables	**(423,119)**	(339,405)
Prepaids and other assets	**(77,901)**	(83,259)
Net debt	**$ 2,639,841**	$ 2,534,287

(1) Unamortized debt issuance costs were obtained from Note 7 - Credit Facilities and Note 8 - Long-term Notes from the consolidated financial statements for the three months ended March 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 and transaction costs.

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

	Three Months Ended	
($ thousands)	**March 31, 2024**	March 31, 2023
Cash flow from operating activities	**$ 383,773**	$ 184,938
Change in non-cash working capital	**32,023**	39,054
Asset retirement obligations settled	**6,511**	4,126
Transaction costs	**1,539**	8,871
Adjusted funds flow	**$ 423,846**	$ 236,989

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended March 31, 2024, except for the matter described below.

On June 20, 2023, Baytex completed the acquisition of Ranger, a publicly traded oil and gas company that was listed on the NASDAQ exchange. Ranger's operations have been included in the consolidated financial statements of Baytex since June 20, 2023. However, Baytex has not had sufficient time to appropriately assess the disclosure controls and procedures and internal controls over financial reporting previously used by Ranger and integrate them with those of Baytex. As a result, the certifying officers have limited the scope of their design of disclosure controls and procedures and internal controls over financial reporting to exclude controls, policies and procedures of Ranger (as permitted by applicable securities laws in Canada and the U.S.). Baytex has a program in place to complete its assessment of the controls, policies and procedures of the acquired operations by June 20, 2024.

During the three months ended March 31, 2024, the assets previously held by Ranger contributed revenues of $309.1 million (representing 31% of total revenues) and net income before tax of $38.2 million (representing 1112% of net income before tax). At March 31, 2024, current assets of $256.4 million, non-current assets of $1.7 billion, current liabilities of $284.3 million and non-current liabilities of $95.6 million were associated with the acquired entity.

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: expectation that we can effectively allocate capital across our assets; our 2024 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; that we expect to increase production and reduce debt through the balance of 2024; 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 or sell assets; 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; 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, 2023, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

The future acquisition of our common shares pursuant to a share buyback (including through its NCIB), if any, and the level thereof is uncertain. Any decision to acquire Common Shares pursuant to a share buyback will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, the 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.

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 are subject to the discretion of the Board of Directors of Baytex.

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

		As at	
	Notes	**March 31, 2024**	December 31, 2023
ASSETS			
Current assets			
Cash		**$ 29,140**	$ 55,815
Trade receivables	17	**423,119**	339,405
Prepaids and other assets	14	**17,467**	21,530
Financial derivatives	17	**5,434**	23,274
		475,160	440,024
Non-current assets			
Exploration and evaluation assets	5	**124,178**	90,919
Oil and gas properties	6	**6,814,062**	6,619,033
Other plant and equipment		**9,187**	7,936
Lease assets		**26,710**	28,145
Prepaids and other assets	14	**60,434**	61,729
Deferred income tax asset	14	**207,764**	213,145
		$ 7,717,495	$ 7,460,931
LIABILITIES			
Current liabilities			
Trade payables	17	**$ 626,137**	$ 477,295
Financial derivatives	17	**14,510**	—
Share-based compensation liability	11	**16,142**	28,508
Dividends payable	10, 17	**18,494**	18,381
Lease obligations		**13,378**	13,391
Asset retirement obligations	9	**19,328**	20,448
		707,989	558,023
Non-current liabilities			
Other long-term liabilities		**19,622**	19,147
Share-based compensation liability	11	**2,525**	7,224
Credit facilities	7	**835,363**	848,749
Long-term notes	8	**1,602,417**	1,562,361
Lease obligations		**15,161**	16,056
Asset retirement obligations	9	**606,161**	602,951
Deferred income tax liability	14	**26,982**	21,333
		3,816,220	3,635,844
SHAREHOLDERS' EQUITY			
Shareholders' capital	10	**6,523,438**	6,527,289
Contributed surplus		**195,090**	193,077
Accumulated other comprehensive income		**801,480**	690,917
Deficit		**(3,618,733)**	(3,586,196)
		3,901,275	3,825,087
		$ 7,717,495	$ 7,460,931

Subsequent events (note 7, note 8, note 10 and note 17)

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended March 31	
	Notes	**2024**	2023
Revenue, net of royalties			
Petroleum and natural gas sales	13	**$ 984,192**	$ 555,336
Royalties		**(209,171)**	(93,253)
		775,021	462,083
Expenses			
Operating		**173,435**	112,408
Transportation		**29,835**	17,005
Blending and other		**64,208**	59,681
General and administrative		**22,412**	11,734
Transaction costs		**1,539**	8,871
Exploration and evaluation	5	**18**	163
Depletion and depreciation		**344,137**	165,999
Share-based compensation	11	**9,523**	9,823
Financing and interest	15	**61,267**	23,725
Financial derivatives loss (gain)	17	**26,862**	(14,625)
Foreign exchange loss (gain)	16	**39,937**	(63)
(Gain) loss on dispositions and swaps		**(2,661)**	336
Other expense (income)		**1,071**	(1,058)
		771,583	393,999
Net income before income taxes		**3,438**	68,084
Income tax expense	14		
Current income tax expense		**1,680**	1,120
Deferred income tax expense		**15,801**	15,523
		17,481	16,643
Net (loss) income		**$ (14,043)**	$ 51,441
Other comprehensive income			
Foreign currency translation adjustment		**110,563**	(548)
Comprehensive income		**$ 96,520**	$ 50,893
Net (loss) income per common share	12		
Basic		**$ (0.02)**	$ 0.09
Diluted		**$ (0.02)**	$ 0.09
Weighted average common shares (000's)	12		
Basic		**821,710**	545,062
Diluted		**821,710**	548,078

See accompanying notes to the condensed consolidated interim financial statements.

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

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	Total equity
Balance at December 31, 2022		$ 5,499,664	$ 89,879	$ 756,195	$ (3,315,321)	**$ 3,030,417**
Vesting of share awards		3,421	—	—	—	**3,421**
Comprehensive (loss) income		—	—	(548)	51,441	**50,893**
Balance at March 31, 2023		$ 5,503,085	$ 89,879	$ 755,647	$ (3,263,880)	**$ 3,084,731**
Balance at December 31, 2023		$ 6,527,289	$ 193,077	$ 690,917	$ (3,586,196)	**$ 3,825,087**
Vesting of share awards	10	1,167	—	—	—	**1,167**
Repurchase of common shares for cancellation	10	(5,018)	2,013	—	—	**(3,005)**
Dividends declared	10	—	—	—	(18,494)	**(18,494)**
Comprehensive income (loss)		—	—	110,563	(14,043)	**96,520**
Balance at March 31, 2024		$ 6,523,438	$ 195,090	$ 801,480	$ (3,618,733)	**$ 3,901,275**

See accompanying notes to the condensed consolidated interim financial statements.

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

	Notes	Three Months Ended March 31 2024	2023
CASH PROVIDED BY (USED IN):			
Operating activities			
Net (loss) income for the period		$ **(14,043)**	$ 51,441
Adjustments for:			
Unrealized foreign exchange loss (gain)	16	**38,718**	(213)
Exploration and evaluation	5	**18**	163
Depletion and depreciation		**344,137**	165,999
Non-cash financing and interest	15	**7,987**	5,350
Non-cash other income	9	**—**	(1,271)
Unrealized financial derivatives loss (gain)	17	**32,350**	(9,210)
(Gain) loss on dispositions and swaps		**(2,661)**	336
Deferred income tax expense	14	**15,801**	15,523
Asset retirement obligations settled	9	**(6,511)**	(4,126)
Change in non-cash working capital		**(32,023)**	(39,054)
Cash flows from operating activities		**383,773**	184,938
Financing activities			
(Decrease) increase in credit facilities		**(21,555)**	24,551
Payments on lease obligations		**(4,872)**	(1,155)
Repurchase of common shares	10	**(3,005)**	—
Dividends declared	10	**(18,494)**	—
Change in non-cash working capital		**2,005**	—
Cash flows (used in) from financing activities		**(45,921)**	23,396
Investing activities			
Additions to exploration and evaluation assets	5	**—**	(490)
Additions to oil and gas properties	6	**(412,551)**	(233,136)
Additions to other plant and equipment		**(2,257)**	(441)
Property acquisitions		**(35,403)**	(506)
Proceeds from dispositions		**25**	235
Change in non-cash working capital		**85,659**	26,985
Cash flows used in investing activities		**(364,527)**	(207,353)
Change in cash		**(26,675)**	981
Cash, beginning of period		**55,815**	5,464
Cash, end of period		$ **29,140**	$ 6,445
Supplementary information			
Interest paid		$ **18,289**	$ 30,469
Income taxes paid		$ **4,544**	$ —

See accompanying notes to the condensed consolidated interim financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is an energy company engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and in Texas, United States. The Company's common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company's head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PREPARATION

The condensed consolidated interim financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). These condensed consolidated financial statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with the annual consolidated financial statements as at and for the year ended December 31, 2023 ("2023 annual consolidated financial statements").

The consolidated financial statements were approved by the Board of Directors of Baytex on May 9, 2024.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of derivative financial instruments and share-based compensation liability, which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company. References to "US$" are to United States ("U.S.") dollars. All financial information is rounded to the nearest thousand, except per share amounts or when otherwise indicated.

The audited 2023 annual consolidated financial statements of the Company are available through its filings on SEDAR+ at www.sedarplus.ca and through the U.S. Securities and Exchange Commission at www.sec.gov.

Estimation Uncertainty

Management makes judgments and assumptions about the future in deriving estimates used in preparation of these consolidated financial statements in accordance with IFRS. Sources of estimation uncertainty include estimates used to determine economically recoverable oil, natural gas, and natural gas liquids reserves, the recoverable amount of long-lived assets or cash generating units, the fair value of financial derivatives, the provision for asset retirement obligations and the provision for income taxes and the related deferred tax assets and liabilities.

Environmental Reporting Regulations

Environmental reporting for public enterprises continues to evolve and the Company may be subject to additional future disclosure requirements. The International Sustainability Standards Board ("ISSB") has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Sustainability Standards Board has released proposed standards that are aligned with the ISSB release, but 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.

Material Accounting Policies

Except as described below, the accounting policies, critical accounting judgments and significant estimates used in these consolidated financial statements are consistent with those used in the preparation of the 2023 annual consolidated financial statements.

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.

In October 2022, the IASB issued *Non-current Liabilities with Covenants* which amended IAS 1 *Presentation of Financial Statements*. The amendments specify the classification and disclosure of a liability with covenants and is effective January 1, 2024.

These amendments have not had a material impact on our consolidated financial statements.

3. 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 is 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 preliminary purchase price equation is based on management's best estimate of the assets acquired and liabilities assumed. Adjustments to these initial estimates may be required upon finalizing the value of net assets acquired which will be completed during the second quarter of 2024. There were no measurement period adjustments recorded during the three months ended March 31, 2024.

	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 [3]	$ 2,337,173	$ 3,096,404
Working capital deficiency excluding bank debt and financial derivatives [3][4]	(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 [4]	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 will be recognized over the remaining future service periods (note 11). 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) During 2023, adjustments were recorded to the preliminary fair value to reflect circumstances that existed as at the acquisition date. These adjustments relate to an update in operating results which increased our working capital deficiency by $16.4 million (US$12.4 million) with an offset to oil and gas properties and an increase in the deferred income tax asset of $1.6 million (US$1.2 million) as a result.

(4) 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.

4. SEGMENTED FINANCIAL INFORMATION

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

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

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended March 31	**2024**	2023	**2024**	2023	**2024**	2023	**2024**	2023
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 416,313**	$ 385,622	**$ 567,879**	$ 169,714	**$ —**	$ —	**$ 984,192**	$ 555,336
Royalties	**(56,564)**	(43,855)	**(152,607)**	(49,398)	**—**	—	**(209,171)**	(93,253)
	359,749	341,767	**415,272**	120,316	**—**	—	**775,021**	462,083
Expenses								
Operating	**85,403**	91,180	**88,032**	21,228	**—**	—	**173,435**	112,408
Transportation	**18,210**	17,005	**11,625**	—	**—**	—	**29,835**	17,005
Blending and other	**64,208**	59,681	**—**	—	**—**	—	**64,208**	59,681
General and administrative	**—**	—	**—**	—	**22,412**	11,734	**22,412**	11,734
Transaction costs	**—**	—	**—**	—	**1,539**	8,871	**1,539**	8,871
Exploration and evaluation	**18**	163	**—**	—	**—**	—	**18**	163
Depletion and depreciation	**116,996**	119,471	**224,439**	44,964	**2,702**	1,564	**344,137**	165,999
Share-based compensation	**—**	—	**—**	—	**9,523**	9,823	**9,523**	9,823
Financing and interest	**—**	—	**—**	—	**61,267**	23,725	**61,267**	23,725
Financial derivatives loss (gain)	**—**	—	**—**	—	**26,862**	(14,625)	**26,862**	(14,625)
Foreign exchange loss (gain)	**—**	—	**—**	—	**39,937**	(63)	**39,937**	(63)
(Gain) loss on dispositions and swaps	**(2,411)**	336	**(250)**	—	**—**	—	**(2,661)**	336
Other expense (income)	**—**	(1,271)	**—**	—	**1,071**	213	**1,071**	(1,058)
	282,424	286,565	**323,846**	66,192	**165,313**	41,242	**771,583**	393,999
Net income (loss) before income taxes	**77,325**	55,202	**91,426**	54,124	**(165,313)**	(41,242)	**3,438**	68,084
Income tax expense								
Current income tax expense							**1,680**	1,120
Deferred income tax expense							**15,801**	15,523
							17,481	16,643
Net (loss) income	**$ 77,325**	$ 55,202	**$ 91,426**	$ 54,124	**$ (165,313)**	$ (41,242)	**$ (14,043)**	$ 51,441
Additions to exploration and evaluation assets	**—**	490	**—**	—	**—**	—	**—**	490
Additions to oil and gas properties	**158,126**	184,116	**254,425**	49,020	**—**	—	**412,551**	233,136
Property acquisitions	**34,275**	506	**1,128**	—	**—**	—	**35,403**	506
Proceeds from dispositions	**(25)**	(235)	**—**	—	**—**	—	**(25)**	(235)

	March 31, 2024	December 31, 2023
Canadian assets	**$ 2,422,342**	$ 2,289,083
U.S. assets	**5,253,822**	5,112,493
Corporate assets	**41,331**	59,355
Total consolidated assets	**$ 7,717,495**	$ 7,460,931

5. EXPLORATION AND EVALUATION ASSETS

	March 31, 2024	December 31, 2023
Balance, beginning of period	**$ 90,919**	$ 168,684
Property acquisitions	**34,138**	18,486
Divestitures	**—**	(2,965)
Property swaps	**(67)**	1,000
Exploration and evaluation expense	**(18)**	(8,896)
Transfer to oil and gas properties (note 6)	**(794)**	(83,530)
Foreign currency translation	**—**	(1,860)
Balance, end of period	**$ 124,178**	$ 90,919

At March 31, 2024 and December 31, 2023, there were no indicators of impairment or impairment reversal for exploration and evaluation assets in any of the Company's cash generating units ("CGUs").

6. 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 3)	3,096,404	—	3,096,404
Property acquisitions	20,263	—	20,263
Transfers from exploration and evaluation assets (note 5)	83,530	—	83,530
Transfers from lease assets	7,611	—	7,611
Change in asset retirement obligations (note 9)	54,166	—	54,166
Divestitures	(660,920)	317,651	(343,269)
Property swaps	(2,975)	3,756	781
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	412,551	—	412,551
Property acquisitions	1,314	—	1,314
Transfers from exploration and evaluation assets (note 5)	794	—	794
Transfers from lease assets	3,684	—	3,684
Change in asset retirement obligations (note 9)	2,413	—	2,413
Property swaps	997	682	1,679
Foreign currency translation	205,950	(91,921)	114,029
Depletion	—	(341,435)	(341,435)
Balance, March 31, 2024	**$ 16,153,720**	**$ (9,339,658)**	**$ 6,814,062**

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

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 is based on 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%.

7. CREDIT FACILITIES

		March 31, 2024		December 31, 2023
Credit facilities - U.S. dollar denominated (1)	**$**	**223,926**	$	311,980
Credit facilities - Canadian dollar denominated		**626,000**		552,756
Credit facilities - principal (2)		**849,926**		864,736
Unamortized debt issuance costs		**(14,563)**		(15,987)
Credit facilities	**$**	**835,363**	$	848,749

(1) U.S. dollar denominated credit facilities balance was US$165.5 million as at March 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 March 31, 2024 is the result of net repayments of $21.6 million, partially offset by an increase in the reported amount of U.S. denominated debt of $6.8 million due to foreign exchange.

At March 31, 2024, Baytex had US$1.1 billion ($1.5 billion) of revolving credit facilities (the "Credit Facilities") that mature on April 1, 2026. 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. Advances under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance discount rates or secured overnight financing rates ("SOFR"), plus applicable margins.

The weighted average interest rate on the Credit Facilities was 8.1% for the three months ended March 31, 2024 (6.0% for three months ended March 31, 2023).

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at March 31, 2024.

Covenant Description	Position as at March 31, 2024	Covenant
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0.4:1.0**	**3.5:1.0**
Interest Coverage (3) (Minimum Ratio)	**10.3:1.0**	**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 March 31, 2024, the Company's Senior Secured Debt totaled $849.9 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 March 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 expense, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Financing and interest expense for the twelve months ended March 31, 2024 was $211.3 million.
(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade payables, share-based compensation liability, dividends payable, asset retirement obligations, leases, deferred income tax liabilities, other long-term liabilities and financial derivative liabilities. As at March 31, 2024, the Company's Total Debt totaled $2.5 billion of principal amounts outstanding.

At March 31, 2024, Baytex had $5.7 million of outstanding letters of credit, $4.3 million of which is under a $20 million uncommitted unsecured demand revolving letter of credit facility (December 31, 2023 - $5.6 million outstanding). Letters of credit under this facility are guaranteed by Export Development Canada and do not use capacity available under the Credit Facilities.

On May 9, 2024, Baytex extended the maturity of 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. As a result of the amendment, borrowing in Canadian funds currently based on the banker's acceptance rate will be replaced with borrowings based on the Canadian Overnight Repo Rate Average ("CORRA").

8. LONG-TERM NOTES

	March 31, 2024	December 31, 2023
8.75% notes due April 1, 2027 (1)	**$ 554,555**	$ 541,114
8.50% notes due April 30, 2030 (2)	**1,082,600**	1,056,361
Total long-term notes - principal (3)	**1,637,155**	1,597,475
Unamortized debt issuance costs	**(34,738)**	(35,114)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,602,417**	$ 1,562,361

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

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

(3) The increase in the principal amount of long-term notes outstanding from December 31, 2023 to March 31, 2024 is the result of changes in the reported amount of U.S. denominated debt of $39.7 million due to changes in the CAD/USD exchange rate used to translate the U.S. denominated amount of long-term notes outstanding.

On April 1, 2024, we 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.

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

9. ASSET RETIREMENT OBLIGATIONS

	March 31, 2024	December 31, 2023
Balance, beginning of period	**$ 623,399**	$ 588,923
Liabilities incurred (1)	**7,922**	24,185
Liabilities settled	**(6,511)**	(26,416)
Liabilities assumed from corporate acquisition (note 3)	**—**	31,310
Liabilities acquired from property acquisitions	**81**	11
Liabilities divested	**(328)**	(43,153)
Property swaps	**(728)**	76
Accretion (note 15)	**4,927**	20,406
Government grants (2)	**—**	(1,271)
Change in estimate (1)	**3,319**	17,067
Changes in discount and inflation rates (1)(3)	**(8,828)**	12,914
Foreign currency translation	**2,236**	(653)
Balance, end of period	**$ 625,489**	$ 623,399
Less current portion of asset retirement obligations	**19,328**	20,448
Non-current portion of asset retirement obligations	**$ 606,161**	$ 602,951

(1) The total of these items reflects the total change in asset retirement obligations of $2.4 million per Note 6 - 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 three months ended March 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 March 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 March 31, 2024 were 4.3% and 2.2%, respectively (December 31, 2023 - 4.0% and 2.1%).

10. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at March 31, 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**	**$**	**5,499,664**
Issued on corporate acquisition	311,370		1,326,435
Vesting of share awards	5,892		26,229
Common shares repurchased and cancelled	(40,511)		(325,039)
Balance, December 31, 2023	**821,681**	**$**	**6,527,289**
Vesting of share awards	272		1,167
Common shares repurchased and cancelled	(631)		(5,018)
Balance, March 31, 2024	**821,322**	**$**	**6,523,438**

Normal Course Issuer Bid ("NCIB") Share Repurchases

During 2023, Baytex renewed the NCIB under which Baytex is permitted to purchase for cancellation 68.4 million common shares over the 12-month period commencing June 29, 2023.

Purchases are made on the open market at prices prevailing at the time of the transaction. During the three months ended March 31, 2024, Baytex repurchased and cancelled 0.6 million common shares at an average price of $4.76 per share for total consideration of $3.0 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.

Dividends

On February 28, 2024, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share which was paid on April 1, 2024 for shareholders on record as at March 15, 2024. On May 9, 2024, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on July 2, 2024 for shareholders on record as at June 14, 2024.

11. SHARE-BASED COMPENSATION PLAN

For the three months ended March 31, 2024 the Company recorded total share-based compensation expense of $9.5 million ($9.8 million for the three months ended March 31, 2023) which is comprised of the expense related to cash-settled awards.

The Company's closing share price on the Toronto Stock Exchange on March 31, 2024 was $4.89 (December 31, 2023 - $4.38 and March 31, 2023 - $5.07).

Share Award Incentive Plan

Baytex has a Share Award Incentive Plan pursuant to which it issues restricted and performance awards. A restricted award entitles the holder of each award to receive one common share of Baytex or the equivalent cash value at the time of vesting. A performance award entitles the holder of each award to receive between zero and two common shares or the 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 Share Awards vest in equal tranches on the first, second and third anniversaries of the grant date. The cumulative expense is recognized at fair value at each period end and is included in share-based compensation liability.

In 2023, Baytex became the successor to Ranger's Share Award Plan (note 3). Awards outstanding as at the closing day 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 three months ended March 31, 2024 was $4.27 per restricted and performance award ($5.49 for the three months ended March 31, 2023).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards	Total number of share awards
Balance, December 31, 2022	**762**	**4,796**	**5,558**
Granted	41	2,641	2,682
Assumed on corporate acquisition (1)	10,789	—	10,789
Vested	(9,302)	(3,767)	(13,069)
Forfeited	(11)	(315)	(326)
Balance, December 31, 2023	**2,279**	**3,355**	**5,634**
Granted	—	2,304	2,304
Added by performance factor	—	523	523
Vested	(1,193)	(2,443)	(3,636)
Balance, March 31, 2024	**1,086**	**3,739**	**4,825**

(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 3) while the remaining fair value of the share awards assumed by Baytex will be recognized over the remaining future service periods.

Incentive Award Plan

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

During the three months ended March 31, 2024, Baytex granted 3.3 million awards under the Incentive Award Plan at a fair value of $4.26 per award (1.5 million awards at $5.49 per award for the three months ended March 31, 2023). At March 31, 2024 there were 5.3 million awards outstanding under the Incentive Award Plan (4.5 million awards outstanding at 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.

During the three months ended March 31, 2024, Baytex granted 0.1 million awards under the DSU Plan at a fair value of $4.29 per award (0.2 million awards at $5.49 per award for the three months ended March 31, 2023). At March 31, 2024, there were 1.3 million awards outstanding under the DSU Plan (1.2 million awards outstanding at December 31, 2023).

12. NET INCOME PER SHARE

Baytex calculates basic income or loss per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted to common shares. The treasury stock method is used to determine the dilutive effect of share awards whereby the potential conversion of share awards and the amount of compensation expense, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the period.

	Three Months Ended March 31					
	2024			2023		
	Net loss	**Weighted average common shares (000s)**	**Net loss per share**	Net income	Weighted average common shares (000s)	Net income per share
Net (loss) income - basic	**$ (14,043)**	**821,710**	**$ (0.02)**	$ 51,441	545,062	$ 0.09
Dilutive effect of share awards	**—**	**—**	**—**	—	3,016	—
Net (loss) income - diluted	**$ (14,043)**	**821,710**	**$ (0.02)**	$ 51,441	548,078	$ 0.09

For the three months ended March 31, 2024, all share awards were excluded from the calculation of diluted loss per share as their effect was anti-dilutive given the Company recorded a loss. For the three months ended March 31, 2023, no share awards were excluded from the calculation of diluted income per share as their effect was dilutive.

13. PETROLEUM AND NATURAL GAS SALES

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

	Three Months Ended March 31					
	2024			2023		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 95,221**	**$ 505,894**	**$ 601,115**	$ 146,456	$ 142,011	$ 288,467
Heavy oil	**304,924**	**—**	**304,924**	217,085	—	217,085
NGL	**6,368**	**39,562**	**45,930**	6,059	15,774	21,833
Natural gas sales	**9,800**	**22,423**	**32,223**	16,022	11,929	27,951
Total petroleum and natural gas sales	**$ 416,313**	**$ 567,879**	**$ 984,192**	$ 385,622	$ 169,714	$ 555,336

Included in accounts receivable at March 31, 2024 is $353.1 million of accrued receivables related to delivered volumes (December 31, 2023 - $271.1 million).

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Three Months Ended March 31	
	2024	2023
Net income before income taxes	**$ 3,438**	$ 68,084
Expected income taxes at the statutory rate of 24.64% (2023 – 24.80%)	**847**	16,885
Change in income taxes resulting from:		
Effect of foreign exchange	**4,847**	(30)
Effect of rate adjustments for foreign jurisdictions	**(1,817)**	(2,176)
Effect of change in deferred tax benefit not recognized (1)	**11,729**	(30)
Repatriation and related taxes	**2,277**	—
Adjustments, assessments and other	**(402)**	1,994
Income tax expense	**$ 17,481**	$ 16,643

(1) A deferred tax asset of $52.1 million remains unrecognized due to uncertainty surrounding future commodity prices and future capital gains (December 31, 2023 - $40.4 million). These deferred income tax assets relate to capital losses of $141.5 million and non-capital losses of $140.8 million.

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

We remain confident that the tax filings of the affected entities are correct and will defend our tax filing positions. During Q4/2023, we purchased $272.5 million of insurance coverage for a premium of $50.3 million which will help manage the litigation risk associated with this matter. The most recent reassessments issued by the CRA assert taxes owing by the trusts of $244.8 million, late payment interest of $166.6 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 potentially 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.

15. FINANCING AND INTEREST

	Three Months Ended March 31	
	2024	2023
Interest on Credit Facilities	**$ 18,289**	$ 6,216
Interest on long-term notes	**34,678**	12,094
Interest on lease obligations	**313**	65
Cash interest	**$ 53,280**	$ 18,375
Amortization of debt issue costs	**3,060**	524
Accretion on asset retirement obligations (note 9)	**4,927**	4,826
Financing and interest	**$ 61,267**	$ 23,725

16. FOREIGN EXCHANGE

	Three Months Ended March 31	
	2024	2023
Unrealized foreign exchange loss (gain)	**$ 38,718**	$ (213)
Realized foreign exchange loss	**1,219**	150
Foreign exchange loss (gain)	**$ 39,937**	$ (63)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

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

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

	March 31, 2024		December 31, 2023		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
Fair value through profit and loss					
Financial derivatives	**$ 5,434**	**$ 5,434**	$ 23,274	$ 23,274	Level 2
Total	**$ 5,434**	**$ 5,434**	$ 23,274	$ 23,274	
Amortized cost					
Cash	**$ 29,140**	**$ 29,140**	$ 55,815	$ 55,815	—
Trade receivables	**423,119**	**423,119**	339,405	339,405	—
Total	**$ 452,259**	**$ 452,259**	$ 395,220	$ 395,220	
Financial Liabilities					
Fair value through profit and loss					
Financial derivatives	**$ (14,510)**	**$ (14,510)**	$ —	$ —	Level 2
Total	**$ (14,510)**	**$ (14,510)**	$ —	$ —	
Amortized cost					
Trade payables	**$ (626,137)**	**$ (626,137)**	$ (477,295)	$ (477,295)	—
Dividends payable	**(18,494)**	**(18,494)**	(18,381)	(18,381)	—
Credit Facilities	**(835,363)**	**(849,926)**	(848,749)	(864,736)	—
Long-term notes	**(1,602,417)**	**(1,710,974)**	(1,562,361)	(1,653,118)	Level 1
Total	**$ (3,082,411)**	**$ (3,205,531)**	$ (2,906,786)	$ (3,013,530)	

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2024 and 2023.

Foreign Currency Risk

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

	Assets		Liabilities	
	March 31, 2024	December 31, 2023	**March 31, 2024**	December 31, 2023
U.S. dollar denominated	**US$10,376**	US$17,923	**US$1,270,700**	US$1,249,725

Commodity Price Risk

Financial Derivative Contracts

As at May 9, 2024 Baytex had the following commodity financial derivative contracts for the period subsequent to March 31, 2024.

	Remaining Period	Volume	Price/Unit [1]	Index
Oil				
Basis differential	Apr 2024 to Jun 2024	4,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.10/bbl	WCS
Basis differential	July 2024 to Dec 2024	9,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.34/bbl	WCS
Basis differential	Apr 2024 to Dec 2024	3,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.27/bbl	WCS
Basis differential [2]	July 2024 to Dec 2024	3,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.25/bbl	WCS
Basis differential	July 2024 to Dec 2024	6,000 bbl/d	WTI less US$13.58/bbl	WCS
Basis differential	Apr 2024 to Dec 2024	2,750 bbl/d	WTI less US$2.94/bbl	MSW
Basis differential	July 2024 to Dec 2024	3,500 bbl/d	WTI less US$2.78/bbl	MSW
Basis differential [2]	Jan 2025 to Dec 2025	2,000 bbl/d	WTI less US$2.75/bbl	MSW
Collar	Apr 2024 to Jun 2024	35,250 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	10,000 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Sep 2024	10,000 bbl/d	US$60.00/US$100.00	WTI
Collar	Oct 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$94.15	WTI
Collar	July 2024 to Dec 2024	1,500 bbl/d	US$60.00/US$90.35	WTI
Collar	July 2024 to Dec 2024	1,000 bbl/d	US$60.00/US$90.00	WTI
Collar	July 2024 to Dec 2024	2,000 bbl/d	US$60.00/US$85.00	WTI
Collar	July 2024 to Dec 2024	2,000 bbl/d	US$60.00/US$84.60	WTI
Collar	July 2024 to Dec 2024	5,000 bbl/d	US$60.00/US$84.15	WTI
Collar	Oct 2024 to Dec 2024	3,500 bbl/d	US$60.00/US$87.10	WTI
Collar	Oct 2024 to Dec 2024	3,500 bbl/d	US$60.00/US$85.75	WTI
Collar	Jan 2025 to Mar 2025	5,000 bbl/d	US$60.00/US$88.70	WTI
Collar [2]	Jan 2025 to Mar 2025	2,500 bbl/d	US$60.00/US$90.20	WTI
Collar [2]	Jan 2025 to Mar 2025	2,500 bbl/d	US$60.00/US$90.05	WTI
Collar [2]	Jan 2025 to Mar 2025	2,500 bbl/d	US$60.00/US$90.00	WTI
Collar [2]	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$94.25	WTI
Collar [2]	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$93.90	WTI
Collar [2]	Jan 2025 to Jun 2025	5,000 bbl/d	US$60.00/US$91.95	WTI
Collar [2]	Jan 2025 to Jun 2025	2,500 bbl/d	US$60.00/US$90.00	WTI
Natural Gas				
Collar	Apr 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.19	NYMEX
Collar	Apr 2024 to Dec 2024	8,500 mmbtu/d	US$3.00/US$4.15	NYMEX
Collar	Apr 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.10	NYMEX
Collar	Apr 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.09	NYMEX
Collar	Apr 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.06	NYMEX
Collar	Apr 2024 to Jun 2024	11,538 mmbtu/d	US$2.33/US$3.00	NYMEX
Collar	Jan 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.01	NYMEX
Collar [2]	Jan 2025 to Dec 2025	7,000 mmbtu/d	US$3.00/US$4.32	NYMEX

(1) Based on the weighted average price per unit for the period.
(2) Contract entered subsequent to March 31, 2024.

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

	Three Months Ended March 31	
	2024	2023
Realized financial derivatives gain	**$ (5,488)**	$ (5,415)
Unrealized financial derivatives loss (gain)	**32,350**	(9,210)
Financial derivatives loss (gain)	**$ 26,862**	$ (14,625)

18. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain a strong balance sheet that provides financial flexibility to execute its development programs, provide returns to shareholders and optimize its portfolio through strategic acquisitions. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At March 31, 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, 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.

	March 31, 2024	December 31, 2023
Credit Facilities	**$ 835,363**	$ 848,749
Unamortized debt issuance costs - Credit Facilities (note 7)	**14,563**	15,987
Long-term notes	**1,602,417**	1,562,361
Unamortized debt issuance costs - Long-term notes (note 8)	**34,738**	35,114
Trade payables	**626,137**	477,295
Share-based compensation liability	**18,667**	35,732
Dividends payable	**18,494**	18,381
Other long-term liabilities	**19,622**	19,147
Cash	**(29,140)**	(55,815)
Trade receivables	**(423,119)**	(339,405)
Prepaids and other assets	**(77,901)**	(83,259)
Net Debt	**$ 2,639,841**	$ 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 and transaction costs.

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

	Three Months Ended March 31	
	2024	2023
Cash flows from operating activities	**$ 383,773**	$ 184,938
Change in non-cash working capital	**32,023**	39,054
Asset retirement obligations settled	**6,511**	4,126
Transaction costs	**1,539**	8,871
Adjusted Funds Flow	**$ 423,846**	$ 236,989