Q1 REPORT
2023

BAYTEX ANNOUNCES FIRST QUARTER 2023 RESULTS

CALGARY, ALBERTA (May 4, 2023) - Baytex Energy Corp. ("Baytex") (TSX:BTE) (NYSE:BTE) reports its operating and financial results for the three months ended March 31, 2023 (all amounts are in Canadian dollars unless otherwise noted).

"We continued to deliver on our operating and financial targets in the first quarter, which included strong results from our Peavine Clearwater development. We continue to make significant progress on the Ranger acquisition, which materially increases Eagle Ford scale in Texas, while building a quality operating capability in a premier basin. The combined company will deliver a powerful combination of substantial free cash flow and increased shareholder returns on a per-share basis. We are in a strong financial position that is supported by significant liquidity and a balanced note maturity profile and we are excited to increase direct shareholder returns to 50% of free cash flow on closing of the acquisition," commented Eric T. Greager, President and Chief Executive Officer.

Highlights

- Entered into an agreement to acquire Ranger Oil Corporation ("Ranger") for approximately US$2.5 billion.
- Generated production of 86,760 boe/d (84% oil and NGL) in Q1/2023, a 7% increase over Q1/2022.
- Delivered adjusted funds flow[1] of $237 million ($0.43 per basic share) in Q1/2023.
- Reported cash flows from operating activities of $185 million ($0.34 per basic share) in Q1/2023.
- Exploration and development expenditures totaled $234 million in Q1/2023, consistent with our full-year plan.
- Generated production from our Clearwater play at Peavine of 11,760 bbl/d in Q1/2023. The first 12 wells from our 2023 drilling program at Peavine generated an average 30-day initial production rate of 661 bbl/d per well.
- Subsequent to quarter-end, completed a US$800 million private offering of senior unsecured notes due 2030 that bear interest at a rate of 8.5% per annum.

Ranger Acquisition

On February 28, 2023, Baytex announced the acquisition of Ranger (the "Merger"), a pure play Eagle Ford operator. With this transaction, we are building a quality, scaled North American oil-weighted exploration and production company with a portfolio across the Western Canadian Sedimentary Basin and the Eagle Ford. The transaction enhances our inventory and creates a more resilient and sustainable business.

A key consideration of the Merger was our ability to accelerate the planned next phase of our shareholder return framework. On closing, we intend to increase direct shareholder returns to 50% of free cash flow, which includes the expected implementation of a quarterly dividend. The transaction is expected to close late in the second quarter of 2023.

2023 Guidance

Our 2023 production guidance range is unchanged at 86,000 to 89,000 boe/d with budgeted exploration and development expenditures of $575 to $650 million, and does not include the integration of Ranger. Based on the forward strip for 2023[2], we expect to generate approximately $115 million of free cash flow in Q2/2023 and on a stand-alone basis (excluding Ranger) generate approximately $325 million of free cash flow for the full-year 2023. Following closing of the Merger, we plan to provide revised guidance for the full-year 2023.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) 2023 pricing assumptions: WTI - US$71/bbl; WCS differential - US$18/bbl; MSW differential – US$3/bbl, NYMEX Gas - US$2.70/MMbtu; AECO Gas - $2.65/mcf and Exchange Rate (CAD/USD) - 1.35.

	Three Months Ended		
	March 31, 2023	December 31, 2022	March 31, 2022
FINANCIAL (thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales	**$ 555,336**	$ 648,986	$ 673,825
Adjusted funds flow (1)	**236,989**	255,552	279,607
Per share – basic	**0.43**	0.47	0.49
Per share – diluted	**0.43**	0.46	0.49
Free cash flow (2)	**(1,918)**	143,324	121,318
Per share – basic	**—**	0.26	0.21
Per share – diluted	**—**	0.26	0.21
Cash flows from operating activities	**184,938**	303,441	198,974
Per share – basic	**0.34**	0.56	0.35
Per share – diluted	**0.34**	0.55	0.35
Net income	**51,441**	352,807	56,858
Per share – basic	**0.09**	0.65	0.10
Per share – diluted	**0.09**	0.64	0.10
Capital Expenditures			
Exploration and development expenditures	**$ 233,626**	$ 103,634	$ 153,822
Acquisitions and divestitures	**271**	937	32
Total oil and natural gas capital expenditures	**$ 233,897**	$ 104,571	$ 153,854
Net Debt			
Credit facilities	**$ 409,653**	$ 385,394	$ 426,858
Long-term notes	**554,351**	554,597	873,880
Total debt (1)	**964,004**	939,991	1,300,738
Working capital	**31,166**	47,455	(25,058)
Net debt (1)	**$ 995,170**	$ 987,446	$ 1,275,680
Shares Outstanding - basic (thousands)			
Weighted average	**545,062**	546,279	565,518
End of period	**545,553**	544,930	569,214
BENCHMARK PRICES			
Crude oil			
WTI (US$/bbl)	**$ 76.13**	$ 82.64	$ 94.29
MEH oil (US$/bbl)	**77.42**	85.88	96.72
MEH oil differential to WTI (US$/bbl)	**1.29**	3.24	2.43
Edmonton par ($/bbl)	**99.04**	109.57	115.66
Edmonton par differential to WTI (US$/bbl)	**(2.88)**	(1.94)	(2.94)
WCS heavy oil ($/bbl)	**69.44**	77.37	100.99
WCS differential to WTI (US$/bbl)	**(24.77)**	(25.65)	(14.53)
Natural gas			
NYMEX (US$/mmbtu)	**$ 3.42**	$ 6.26	$ 4.95
AECO ($/mcf)	**4.34**	5.58	4.59
CAD/USD average exchange rate	**1.3520**	1.3577	1.2661

	Three Months Ended		
	March 31, 2023	December 31, 2022	March 31, 2022
OPERATING			
Daily Production			
Light oil and condensate (bbl/d)	**31,678**	32,105	34,065
Heavy oil (bbl/d)	**34,191**	32,819	25,236
NGL (bbl/d)	**7,213**	7,661	7,636
Total liquids (bbl/d)	**73,082**	72,585	66,937
Natural gas (mcf/d)	**82,066**	85,679	83,574
Oil equivalent (boe/d @ 6:1) [(3)]	**86,760**	86,864	80,867
Netback (thousands of Canadian dollars)			
Total sales, net of blending and other expense [(2)]	**$ 495,655**	$ 598,812	$ 632,385
Royalties	**(93,253)**	(121,691)	(122,720)
Operating expense	**(112,408)**	(104,335)	(100,766)
Transportation expense	**(17,005)**	(14,817)	(9,215)
Operating netback [(2)]	**$ 272,989**	**$ 357,969**	**$ 399,684**
General and administrative	**(11,734)**	(14,945)	(11,682)
Cash financing and interest	**(18,375)**	(19,711)	(20,427)
Realized financial derivatives gain (loss)	**5,415**	(49,665)	(84,366)
Other [(4)]	**(11,306)**	(18,096)	(3,602)
Adjusted funds flow [(1)]	**$ 236,989**	**$ 255,552**	**$ 279,607**
Netback (per boe) [(5)]			
Total sales, net of blending and other expense [(2)]	**$ 63.48**	$ 74.93	$ 86.89
Royalties	**(11.94)**	(15.23)	(16.86)
Operating expense	**(14.40)**	(13.06)	(13.85)
Transportation expense	**(2.18)**	(1.85)	(1.27)
Operating netback [(2)]	**$ 34.96**	**$ 44.79**	**$ 54.91**
General and administrative	**(1.50)**	(1.87)	(1.61)
Cash financing and interest	**(2.35)**	(2.47)	(2.81)
Realized financial derivatives gain (loss)	**0.69**	(6.21)	(11.59)
Other [(4)]	**(1.45)**	(2.26)	(0.48)
Adjusted funds flow [(1)]	**$ 30.35**	**$ 31.98**	**$ 38.42**

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) 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.

(4) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and cash share-based compensation. Refer to the Q1/2023 MD&A for further information on these amounts.

(5) Calculated as royalties, operating, transportation, general and administrative, cash financing and interest expense or realized financial derivatives loss divided by barrels of oil equivalent production volume for the applicable period.

Return of Capital Framework

In 2022, we made a commitment to return 25% of free cash flow to shareholders through a share buyback program. We executed on this program in 2022, repurchasing 4.3% of our shares outstanding.

On closing of the Merger, we intend to increase direct shareholder returns to 50% of the free cash flow generated by the combined company, allowing us to increase the value of our share buyback program and introduce a dividend. Our share buyback program was placed on hold at the beginning of the year due to the pending Merger but will recommence following closing. To meet our shareholder return commitment, we intend to include 25% of the free cash flow generated from January 1, 2023 until closing in our 2023 share buyback program.

Our existing normal course issuer bid ("NCIB") is set to expire on May 8, 2023. Following closing of the Merger, we intend to file an updated NCIB application with the TSX for a share buyback program representing approximately 10% of our public float and recommend that Baytex pay a quarterly dividend of $0.0225 per share ($0.09 per share annualized). If declared by the Baytex Board of Directors, the initial dividend is expected to be paid in October 2023(1).

Q1/2023 Results

During the first quarter, we delivered strong operating and financial results, consistent with our full-year plan. Production averaged 86,760 boe/d (84% oil and NGLs) as compared to 80,867 boe/d (82% oil and NGLs) in Q1/2022. We delivered adjusted funds flow(2) of $237 million ($0.43 per basic share) and net income of $51 million ($0.09 per basic share).

Exploration and development expenditures totaled $234 million in Q1/2023 (38% of budgeted full-year expenditures) and we participated in the drilling of 118 (96.6 net) wells. Our 2023 exploration and development program is heavily weighted to the first quarter, which is expected to drive strong free cash flow over the balance of the year.

Light Oil - United States

Our light oil assets in the United States are located in the core of the liquids-rich Eagle Ford formation, in the Texas Gulf Coast Basin. Our existing Eagle Ford assets include non-operated working interests in four areas of mutual interest with an average working interest of approximately 25%.

Production in the Eagle Ford averaged 26,109 boe/d (79% oil and NGLs) during Q1/2023 and generated an operating netback(3) of $99 million. We invested $49 million on exploration and development in the Eagle Ford during the quarter and brought 24 (6.4 net) wells onstream. We expect to bring approximately 18 net wells onstream in 2023.

Light Oil - Canada

Our light oil production and development in Canada occurs within the Viking formation in west central Saskatchewan and east central Alberta, and the Duvernay formation in the Pembina area of central Alberta. The Viking assets are a shallow, light oil resource play with strong operating netbacks. The Pembina Duvernay development is an early stage, high operating netback light oil resource play.

Production in the Viking averaged 16,770 boe/d (88% oil and NGL) during Q1/2023 and generated an operating netback(3) of $91 million. We invested $82 million on exploration and development in the Viking during the quarter and brought 64 (59.6 net) wells onstream. We expect to bring approximately 132 net wells onstream in 2023.

Production in the Pembina Duvernay averaged 2,444 boe/d (82% oil and NGL) during Q1/2023. We invested $21 million on exploration and development in the Duvernay during the quarter and drilled four wells of a planned six well program. The remaining two wells will be drilled during the second quarter. Completion activities for the two three-well pads are expected to commence late in the second quarter.

Heavy Oil - Canada

Our heavy oil production and development in Canada occurs within the Bluesky and Spirit River (Clearwater) formations in the Peace River area of northwest Alberta and the Mannville group of formations in the greater Lloydminster region of east central Alberta and west central Saskatchewan. Our heavy oil business includes low decline production with innovative multi-lateral (trident and fishbone) horizontal drilling with strong capital efficiencies. The core of our Clearwater play is located on the Peavine Métis settlement.

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

Our heavy oil assets at Peace River and Lloydminster (excluding Clearwater development) produced a combined 24,588 boe/d (92% oil and NGL) during Q1/2023 and generated an operating netback[1] of $37 million. We invested $52 million on exploration and development during the quarter and brought onstream 2 net Bluesky wells at Peace River and 10.8 net wells at Lloydminster. In addition, we drilled 3 steam assisted gravity drainage ("SAGD") well pairs at Kerrobert that are expected to be onstream during the fourth quarter. In 2023, we plan to drill 7 net Bluesky wells at Peace River and 30 net wells at Lloydminster.

Production in the Peavine Clearwater averaged 11,760 boe/d (100% oil) during Q1/2023 and generated an operating netback of $31 million. We invested $29 million on exploration and development during the quarter and brought 12 net Clearwater wells onstream. All 12 wells have now been onstream for over 30-days and have generated an average 30-day initial production rate of 661 bbl/d per well. In 2023, we plan to drill 31 net Clearwater wells at Peavine.

Across all of our core assets, inventory enhancement continues to be a priority. In Q4/2022 we successfully drilled a Clearwater equivalent test well at Morinville, Alberta, where we have aggregated approximately 30 sections of prospective land. The well was brought onstream in Q1/2023 and has achieved a 30-day initial production rate of 180 bbl/d of 15.5° API crude oil. Notably, this six leg test well is about half the length of full planned development wells. We are encouraged by these initial results and are planning two additional follow-up wells in the second half of 2023.

Senior Notes Financing

On April 27, 2023, we announced the closing of a US$800 million private offering (the "offering") of senior unsecured notes due 2030 (the "Notes"). The Notes bear interest at a rate of 8.5% per annum and mature on April 30, 2030. The gross proceeds of the offering have been deposited into escrow pending satisfaction of certain escrow release conditions, including the consummation of the previously announced Merger with Ranger. Upon satisfaction of the escrow release conditions, Baytex intends to use the net proceeds from the offering, together with borrowings under its credit facilities and term loan, to fund the cash portion of the consideration for the acquisition, to repay certain outstanding indebtedness of Ranger and Baytex and to pay fees and expenses in connection with the Merger.

Risk Management

To manage commodity price movements, we utilize various financial derivative contracts to reduce the volatility of our adjusted funds flow.

For May to December 2023, we have entered into hedges on approximately 35% of our net crude oil exposure utilizing a combination of costless collars on 14,500 bbl/d with a floor price of US$60/bbl and a ceiling price of US$100/bbl and a 5,000 bbl/d purchased put at US$60/bbl.

We intend to hedge approximately 40% of our net crude oil exposure during the 12 months following the closing of the Merger.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q1/2023 financial statements.

Board of Directors Update

On closing of the Merger, Baytex intends to appoint two independent directors from the Ranger Board of Directors to the Baytex Board of Directors. At the time of the Merger announcement, Baytex indicated its intent to appoint Jeffrey E. Wojahn to the Baytex Board of Directors. Baytex is pleased to announce that we also intend to appoint Tiffany ("T.J.") Thom Cepak to the Baytex Board of Directors.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three months ended March 31, 2023 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.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

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

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "believe", "continue", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to but not limited to: that the Merger will result in a combined company that will deliver a powerful combination of substantial free cash flow and increased shareholder returns on a per-share basis; that following the Merger we intend to increase direct shareholder returns to 50% of free cash flow, including implementation of a quarterly dividend of $0.0225 per share ($0.09 per share annualized) and the timing thereof; our expectation for the Merger to enhance our inventory and create a more resilient and sustainable business; our expectation to generate approximately $115 million of free cash flow in Q2/2023 and on a stand-alone basis (excluding Ranger) to generate approximately $325 million of free cash flow for the full-year 2023; our plan to provide revised guidance for the full-year 2023 following closing of the Merger; our intention to include 25% of the free cash flow generated from January 1, 2023 until closing of the Merger in our 2023 share buyback program and, following closing of the Merger, to file an updated NCIB application with the TSX for a share buyback program representing approximately 10% of our public float; our plans and expectations in respect of our drilling program, including to bring approximately 18 net wells onstream in 2023 in the Eagle Ford, our expectation to bring approximately 132 net wells onstream in 2023 in the Viking, our expectation to drill the remaining two wells of our planned six well program in the Pembina Duvernay during the second quarter of 2023 and our plan to drill approximately 31 net Clearwater wells at Peavine; that upon satisfaction of the escrow release conditions, Baytex intends to use the net proceeds from the bond offering, together with borrowings under its credit facilities and term loan, to fund the cash portion of the consideration for the Merger, to repay certain outstanding indebtedness of Ranger and Baytex, and to pay fees and expenses in connection with the Merger; our intention to hedge approximately 40% of our net crude oil exposure during the 12 months following closing of the Merger; and that Baytex intends to appoint Jeffrey E. Wojahn and Tiffany ("T.J.") Thom Cepak to the Baytex Board of Directors on closing of the Merger.

These forward-looking statements are based on certain key assumptions regarding, among other things: the consummation and success of the Merger and our ability to successfully integrate the acquired business into our existing operations; the timing of receipt of regulatory and shareholder and stockholder approvals; the ability of the combined business to realize the anticipated benefits of the transaction; petroleum and natural gas prices and differentials between light, medium and heavy 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; 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 ability to obtain stockholder, shareholder, and regulatory approvals, if any, of the Merger; the ability to complete the Merger on anticipated terms and timetable; the possibility that various closing conditions for the transaction may not be satisfied or waived; risks relating to any unforeseen liabilities of Baytex and Ranger; the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; 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 of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; 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, 2022, 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.

This press release contains information that may be considered a financial outlook under applicable securities laws about Baytex's pro forma capitalization upon completion of the Merger, which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth herein. The actual capitalization of Baytex 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, Baytex undertakes no obligation to update such financial outlook. 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 Baytex's potential future capitalization upon completion of the Merger. Readers are cautioned that the financial outlook contained in this press release is not conclusive and is subject to change.

Dividend Advisory

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. There can be no assurance that Baytex will pay dividends following closing of the Merger.

Specified Financial Measures

In this press release, we refer to certain financial measures (such as free cash flow, operating netback, 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 natural gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers. In addition, this press release contains the terms "adjusted funds flow", "total debt", and "net debt" which are considered capital management measures.

Non-GAAP Financial Measures

Total sales, net of blending and other expense

Total sales, net of blending and other expense is not a measurement based on GAAP in Canada and represents the revenues realized from produced volumes during a period. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

Operating netback

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to petroleum and natural gas sales less blending expense, royalties, production and operating expense and transportation expense. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis and is a key measure used to evaluate our operating performance.

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

	Three Months Ended March 31	
($ thousands)	**2023**	2022
Petroleum and natural gas sales	**$ 555,336**	$ 673,825
Blending and other expense	**(59,681)**	(41,440)
Total sales, net of blending and other expense	**$ 495,655**	$ 632,385
Royalties	**(93,253)**	(122,720)
Operating expense	**(112,408)**	(100,766)
Transportation expense	**(17,005)**	(9,215)
Operating netback	**$ 272,989**	$ 399,684

Free cash flow

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as 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. Our determination of free cash flow may not be comparable to other issuers. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities.

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

	Three Months Ended March 31	
($ thousands)	**2023**	2022
Cash flows from operating activities	**$ 184,938**	$ 198,974
Change in non-cash working capital	**39,054**	77,340
Additions to exploration and evaluation assets	**(490)**	(3,559)
Additions to oil and gas properties	**(233,136)**	(150,263)
Payments on lease obligations	**(1,155)**	(1,174)
Transaction costs	**8,871**	—
Free cash flow	**$ (1,918)**	$ 121,318

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. 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 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

Total debt and Net debt

We use total debt and net debt to monitor our current financial position and to evaluate existing sources of liquidity. We define total debt to be the sum of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs. To arrive at net debt we further adjust for trade and other payables, cash, and trade and other receivables. We believe that these measures assist in providing a more complete understanding of our cash liabilities and provide a key measure to assess our liquidity. We use the principal amounts of the credit facilities and long-term notes outstanding in the calculation of total debt and net debt as these amounts represent our ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the credit facilities and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of capital or repayment obligation.

The following table summarizes our calculation of net debt.

($ thousands)	**March 31, 2023**	December 31, 2022
Credit facilities	**$ 407,473**	$ 383,031
Unamortized debt issuance costs - Credit facilities (1)	**2,180**	2,363
Long-term notes	**547,698**	547,598
Unamortized debt issuance costs - Long-term notes (1)	**6,653**	6,999
Total Debt	**$ 964,004**	$ 987,446
Trade and other payables	**271,022**	272,195
Cash	**(6,445)**	(5,464)
Trade and other receivables	**(233,411)**	(228,485)
Net debt	**$ 995,170**	$ 987,446

(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, 2023.

Adjusted funds flow

Adjusted funds flow is a financial term commonly used in the oil and gas industry. We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends.

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

	Three Months Ended March 31	
($ thousands)	**2023**	2022
Cash flow from operating activities	**$ 184,938**	$ 198,974
Change in non-cash working capital	**39,054**	77,340
Asset retirement obligations settled	**4,126**	3,293
Transaction costs	**8,871**	—
Adjusted funds flow	**$ 236,989**	$ 279,607

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, 2023. 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, 2023					**Three Months Ended March 31, 2022**				
	Heavy Crude Oil (bbl/d)	**Light and Medium Crude Oil (bbl/d)**	**NGL (bbl/d)**	**Natural Gas (Mcf/d)**	**Oil Equivalent (boe/d)**	**Heavy Crude Oil (bbl/d)**	**Light and Medium Crude Oil (bbl/d)**	**NGL (bbl/d)**	**Natural Gas (Mcf/d)**	**Oil Equivalent (boe/d)**
Canada – Heavy										
Peace River	10,783	13	54	11,264	12,727	11,587	5	29	11,125	13,475
Lloydminster	11,648	10	—	1,218	11,861	10,495	15	—	1,787	10,808
Peavine	11,760	—	—	—	11,760	3,154	—	—	—	3,154
Canada - Light										
Viking	—	14,640	193	11,620	16,770	—	15,694	188	11,894	17,865
Duvernay	—	1,063	944	2,623	2,444	—	992	789	2,343	2,172
Remaining Properties	—	672	684	22,395	5,089	—	867	929	24,694	5,911
United States										
Eagle Ford	—	15,280	5,338	32,946	26,109	—	16,492	5,701	31,731	27,482
Total	34,191	31,678	7,213	82,066	86,760	25,236	34,065	7,636	83,574	80,867

Baytex Energy Corp.

Baytex Energy Corp. is an energy company based in Calgary, Alberta. The company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. 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, Vice President, Capital Markets

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, 2023 and 2022
Dated May 4, 2023

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, 2023. This information is provided as of May 4, 2023. 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, 2023 ("Q1/2023") have been compared with the results for the three months ended March 31, 2022 ("Q1/2022"). 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, 2023, its audited comparative consolidated financial statements for the years ended December 31, 2022 and 2021, together with the accompanying notes, and its Annual Information Form ("AIF") for the year ended December 31, 2022. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com 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", "total debt", "net debt" and "net debt to adjusted funds flow ratio" which are capital management measures. Refer to our advisory on forward-looking information and statements and a summary of our specified financial measures at the end of the MD&A.

BAYTEX ENERGY CORP.

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

PROPOSED BUSINESS COMBINATION

On February 28, 2023, Baytex announced that it has entered into a definitive agreement (the "Agreement") to acquire Ranger Oil Corporation ("Ranger"), an oil and gas exploration and production company with operations in the Eagle Ford (the "Merger Transaction"). The Merger Transaction has been unanimously approved by the Boards of Directors of Baytex and Ranger and is expected to close in the second quarter of 2023, subject to approval by the shareholders of both companies and the satisfaction of other customary closing conditions. The Merger Transaction materially increases our Eagle Ford scale and provides an operating platform to effectively allocate capital across the Western Canadian Sedimentary Basin and the Eagle Ford while enhancing per share metrics.

The Merger Transaction creates a more resilient and sustainable business with higher revenues, improved margins and enhanced inventory which will allow for a more robust shareholder return framework. Upon closing, we intend to increase direct returns to shareholders to 50% of free cash flow generated by the combined company, including the expected introduction of a quarterly $0.0225 per share dividend. To meet our shareholder return commitment, we intend to include 25% of the free cash flow generated from January 1, 2023 until closing in our 2023 share buyback program.

The Agreement provides that, upon the occurrence of certain termination events, either of the parties may be required to pay the other party their respective termination fees, being the Ranger termination fee of US$60 million and the Baytex termination fee of US$100 million.

The Merger Transaction will be funded with a combination of cash and shares. Baytex will issue 7.49 common shares for each Ranger share and pay US$13.31 per Ranger share along with assuming Ranger's net debt. The cash portion of the transaction will be funded with Baytex's expanded credit facility which will increase to US$1.1 billion upon the closing of the transaction, up to US$250 million from a two-year term loan facility and the proceeds from the issuance of US$800 million senior unsecured notes due 2030. Baytex closed the US$800 million principal amount senior unsecured note offering on April 27, 2023 with the proceeds deposited into escrow subject to completion of the Merger Transaction.

During the three months ended March 31, 2023, Baytex incurred $8.9 million of transaction costs, including consulting, financial advisory, legal and filing fees related to the Merger. The results of operations and the MD&A do not include the results of Ranger. The Company will include the results of Ranger after closing the Merger Transaction and will update guidance at that time.

FIRST QUARTER HIGHLIGHTS

In addition to entering into the Merger Transaction with Ranger, Baytex delivered strong operating and financial results in Q1/2023. Production of 86,760 boe/d increased 7% from Q1/2022 and reflects growth from our Canadian heavy oil assets along with strong well results from our successful development programs in the U.S. and Canada. We invested $233.6 million on exploration and development expenditures and generated adjusted funds flow(1) of $237.0 million during Q1/2023.

Our capital program for the first half of 2023 is weighted towards Q1/2023 as we complete the majority of our first half drilling in Q1 prior to seasonal conditions which limit our ability to operate in Canada. Our exploration and development expenditures totaled $233.6 million in Q1/2023 and were consistent with our expectations as part of our $575-$650 million annual capital program. We invested $184.6 million in Canada in Q1/2023 and brought 25 (24.8 net) heavy oil wells and 64 (59.6 net) light oil wells on production. Production in Canada averaged 60,651 boe/d during Q1/2023 compared to 53,385 boe/d in Q1/2022 due to the continued strength of our Clearwater assets at Peavine and the overall growth of our heavy oil portfolio. In the U.S. we invested $49.0 million during Q1/2023 and brought 24 (6.4 net) wells on production. Production in the U.S. averaged 26,109 boe/d in Q1/2023 compared to 27,482 boe/d in Q1/2022. Production in the U.S. declined slightly with overall activity decreasing on our non-operated acreage.

Oil prices decreased in Q1/2023 on concerns of an economic slowdown causing lower demand for crude oil as central banks continued to increase interest rates to combat inflation. The WTI and WCS differential benchmarks averaged US$76.13/bbl and US $24.77/bbl during Q1/2023 compared to US$94.29/bbl and US$14.53/bbl respectively in Q1/2022. Adjusted funds flow(1) of $237.0 million and cash flows from operating activities of $184.9 million for Q1/2023 reflect commodity prices that were lower relative to Q1/2022 when we generated adjusted funds flow of $279.6 million and cash flows from operating activities of $199.0 million.

With our active Q1/2023 capital program and lower commodity prices, net debt(1) of $995.2 million at March 31, 2023 was consistent with $987.4 million at December 31, 2022. On closing of the Merger Transaction, we intend to allocate 50% of the free cash flow generated by the combined company to shareholder returns including an expected $0.0225 per share quarterly dividend. To meet our shareholder return commitment, we intend to contribute 25% of free cash flow generated from January 1, 2023 until closing of the merger to our 2023 share buyback program.

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

2023 GUIDANCE

The following table compares our 2023 annual guidance to our Q1/2023 results and does not include Ranger. We will provide updated 2023 guidance once we close the Merger Transaction. Our 2023 production guidance range is unchanged at 86,000 to 89,000 boe/d with budgeted exploration and development expenditures of $575-$650 million.

	2023 Annual Guidance (1)	Q1/2023 Results
Exploration and development expenditures	$575 - $650 million	$233.6 million
Production (boe/d)	86,000 - 89,000	86,760
Expenses:		
Average royalty rate (2)	20.0% - 22.0%	18.8%
Operating (3)	$14.00 - $14.75/boe	$14.40/boe
Transportation (3)	$1.90 - $2.10/boe	$2.18/boe
General and administrative (3)	$52 million ($1.63/boe)	$11.7 million ($1.50/boe)
Cash Interest (3)	$65 million ($2.04/boe)	$18.4 million ($2.35/boe)
Leasing expenditures	$4 million	$1.2 million
Asset retirement obligations	$25 million	$4.1 million

(1) As announced on December 7, 2022.
(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.

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 Eagle Ford assets in Texas.

Production

	Three Months Ended March 31					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**16,398**	**15,280**	**31,678**	17,573	16,492	34,065
Heavy oil	**34,191**	**—**	**34,191**	25,236	—	25,236
Natural Gas Liquids (NGL)	**1,875**	**5,338**	**7,213**	1,935	5,701	7,636
Total liquids (bbl/d)	**52,464**	**20,618**	**73,082**	44,744	22,193	66,937
Natural gas (mcf/d)	**49,120**	**32,946**	**82,066**	51,843	31,731	83,574
Total production (boe/d)	**60,651**	**26,109**	**86,760**	53,385	27,482	80,867
Production Mix						
Segment as a percent of total	**70 %**	**30 %**	**100 %**	66 %	34 %	100 %
Light oil and condensate	**27 %**	**59 %**	**37 %**	33 %	60 %	42 %
Heavy oil	**56 %**	**— %**	**39 %**	47 %	— %	31 %
NGL	**3 %**	**20 %**	**8 %**	4 %	21 %	9 %
Natural gas	**14 %**	**21 %**	**16 %**	16 %	19 %	18 %

Production was 86,760 boe/d for Q1/2023 compared to 80,867 boe/d for Q1/2022. Total production was higher in Q1/2023 compared to Q1/2022 due to our successful development program in Canada which includes strong well results from our Clearwater development program.

In Canada, production was 60,651 boe/d for Q1/2023 compared to 53,385 boe/d for Q1/2022. Our successful development program and strong well performance from our Clearwater assets at Peavine resulted in a 7,266 boe/d increase in production for Q1/2023 relative to Q1/2022. Production at Peavine averaged 11,760 boe/d in Q1/2023 compared to 3,154 boe/d in Q1/2022.

In the U.S., production was 26,109 boe/d for Q1/2023 compared to 27,482 boe/d for Q1/2022. Production in the U.S. was lower during Q1/2023 as a result of lower activity on our lands along with a greater proportion of wells were brought on production later in the quarter as compared to Q1/2022. We initiated production from 24 (6.4 net) wells during Q1/2023 compared to 17 (4.8 net) wells during Q1/2022.

Total production of 86,760 boe/d for Q1/2023 is consistent with expectations and is within our annual guidance of approximately 86,000 - 89,000 boe/d for 2023.

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 lower during Q1/2023 as central banks continued to raise interest rates to combat inflation which resulted in expectations for slower economic activity and demand for crude oil. As a result, the WTI benchmark price averaged US$76.13/bbl for Q1/2023 compared to Q1/2022 when WTI was higher due to uncertainty around supply caused by geopolitical factors and averaged US$94.29/bbl.

We compare the price received for our U.S. crude oil production to the Magellan East Houston ("MEH") stream at Houston, Texas which is a representative benchmark for light oil pricing at the U.S. Gulf coast. The MEH benchmark averaged US$77.42/bbl during Q1/2023 which is lower than US$96.72/bbl during Q1/2022. The MEH benchmark trades at a premium to WTI as a result of access to global markets. The MEH benchmark premium to WTI was US$1.29/bbl for Q1/2023 compared to a premium of US$2.43/bbl for Q1/2022. The MEH benchmark traded at a lower premium to WTI in Q1/2023 compared to Q1/2022 as a result of refinery turnarounds and power outages that disrupted processing capacity at the Gulf Coast in Q1/2023.

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 $99.04/bbl during Q1/2023 compared to $115.66/bbl during Q1/2022. Edmonton par traded at a discount to WTI of US$2.88/bbl for Q1/2023 which is consistent with a discount of US$2.94/bbl for Q1/2022.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS heavy oil price for Q1/2023 averaged $69.44/bbl compared to $100.99/bbl for the same period of 2022. The WCS heavy oil differential was US$24.77/bbl in Q1/2023 which is wider than US$14.53/bbl for Q1/2022 due to refinery turnarounds which reduced demand for Canadian heavy oil in 2023.

Natural Gas

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. Reduced global demand from milder winter temperatures as well as export terminal disruptions resulted in a decrease in the NYMEX natural gas benchmark that averaged US$3.42/mmbtu for Q1/2023 compared to US$4.95/mmbtu for Q1/2022.

In Canada, we receive natural gas pricing based on the AECO benchmark which continues to trade at a discount to NYMEX as a result of limited market access for Canadian natural gas production. The AECO benchmark averaged $4.34/mcf during Q1/2023 which is relatively consistent with $4.59/mcf for Q1/2022.

The following tables compare select benchmark prices and our average realized selling prices for the three months ended March 31, 2023 and 2022.

	Three Months Ended March 31		
	2023	2022	Change
Benchmark Averages			
WTI oil (US$/bbl) (1)	**76.13**	94.29	(18.16)
MEH oil (US$/bbl) (2)	**77.42**	96.72	(19.30)
MEH oil differential to WTI (US$/bbl)	**1.29**	2.43	(1.14)
Edmonton par oil ($/bbl) (3)	**99.04**	115.66	(16.62)
Edmonton par oil differential to WTI (US$/bbl)	**(2.88)**	(2.94)	0.06
WCS heavy oil ($/bbl) (4)	**69.44**	100.99	(31.55)
WCS heavy oil differential to WTI (US$/bbl)	**(24.77)**	(14.53)	(10.24)
AECO natural gas ($/mcf) (5)	**4.34**	4.59	(0.25)
NYMEX natural gas (US$/mmbtu) (6)	**3.42**	4.95	(1.53)
CAD/USD average exchange rate	**1.3520**	1.2661	0.0859

(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					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) (1)	**$ 99.23**	**$ 103.27**	**$ 101.18**	$ 113.91	$ 121.82	$ 117.74
Heavy oil, net of blending and other expense ($/bbl) (2)	**51.15**	**—**	**51.15**	89.38	—	89.38
NGL ($/bbl) (1)	**35.90**	**32.83**	**33.63**	42.96	42.89	42.91
Natural gas ($/mcf) (1)	**3.53**	**4.02**	**3.73**	4.64	6.06	5.17
Total sales, net of blending and other expense ($/boe) (2)	**$ 59.71**	**$ 72.22**	**$ 63.48**	$ 85.81	$ 89.00	$ 86.89

(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 $63.48/boe for Q1/2023 compared to $86.89/boe for Q1/2022. In Canada, our realized price of $59.71/boe for Q1/2023 was $26.10/boe lower than $85.81/boe for Q1/2022. Our realized price in the U.S. was $72.22/boe in Q1/2023 which is $16.78/boe lower than $89.00/boe in Q1/2022. The decrease in our realized price in Canada and the U.S. for Q1/2023 was a result of lower North American benchmark prices relative to the same period of 2022.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price(2) was $99.23/bbl for Q1/2023 compared to $113.91/bbl for Q1/2022. Our realized light oil and condensate price for Q1/2023 decreased with the decline in the benchmark price and represents a premium to the Edmonton par price of $0.19/bbl for Q1/2023 compared to a discount of $1.75/bbl in Q1/2022. We realized a premium to the Edmonton par price due to strong price realizations on certain marketing arrangements within our Viking business unit for Q1/2023.

We compare the price received for our U.S. light oil and condensate production to the MEH benchmark. Our realized light oil and condensate price averaged $103.27/bbl for Q1/2023 compared to $121.82/bbl for Q1/2022. Expressed in U.S. dollars, our realized light oil and condensate price of US$76.38/bbl for Q1/2023 represents a discount to MEH of US$1.04/bbl for Q1/2023, which is consistent with a discount of US$0.50/bbl for Q1/2022.

Our realized heavy oil price, net of blending and other expense(1) averaged $51.15/bbl in Q1/2023 compared to $89.38/bbl in Q1/2022. This was $38.23/bbl lower than Q1/2022, compared to a $31.55/bbl decrease in the WCS benchmark price over the same period. Our realized price decreased more than the benchmark price as the cost of condensate purchased for blending was higher relative to sales of the blended product based on the WCS benchmark in Q1/2023 compared to Q1/2022.

Our realized NGL price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes and changes in the market prices for the underlying products. Our realized NGL price(2) was $33.63/bbl in Q1/2023 or 33% of WTI (expressed in Canadian dollars) compared to $42.91/bbl or 36% of WTI (expressed in Canadian dollars) in Q1/2022. The decrease in our realized price is primarily a result of lower WTI pricing in Q1/2023 relative to Q1/2022 as our realized price as a percentage of WTI was relatively consistent in both periods.

We compare our realized natural gas price in Canada to the AECO benchmark price and to the NYMEX benchmark in the U.S. A portion of our natural gas in Canada and the U.S. is based on the respective daily index pricing which fluctuates independently from the associated monthly index. In the U.S., our realized natural gas price(2) was US$2.97/mcf for Q1/2023 compared to US$4.79/mcf for Q1/2022 which is primarily the result of the decrease in the NYMEX benchmark over the same period. In Canada our realized natural gas price was $3.53/mcf for Q1/2023 compared to $4.64/mcf in Q1/2022 which declined more than the decline in the AECO benchmark over the same periods due to certain spot sales below the monthly index.

(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					
	2023			2022		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 146,456**	**$ 142,011**	**$ 288,467**	$ 180,156	$ 180,820	$ 360,976
Heavy oil	**217,085**	**—**	**217,085**	244,439	—	244,439
NGL	**6,059**	**15,774**	**21,833**	7,483	22,007	29,490
Total oil sales	**369,600**	**157,785**	**527,385**	432,078	202,827	634,905
Natural gas sales	**16,022**	**11,929**	**27,951**	21,626	17,294	38,920
Total petroleum and natural gas sales	**385,622**	**169,714**	**555,336**	453,704	220,121	673,825
Blending and other expense	**(59,681)**	**—**	**(59,681)**	(41,440)	—	(41,440)
Total sales, net of blending and other expense (1)	**$ 325,941**	**$ 169,714**	**$ 495,655**	$ 412,264	$ 220,121	$ 632,385

(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 $495.7 million for Q1/2023 decreased $136.7 million from $632.4 million reported for Q1/2022. The decrease in total sales is primarily the result of lower realized prices in Q1/2023 relative to Q1/2022.

In Canada, total sales, net of blending and other expense, of $325.9 million for Q1/2023 decreased $86.3 million from $412.3 million reported for Q1/2022. The decrease was primarily a result of lower realized pricing for Q1/2023 relative to Q1/2022 which resulted in a $142.4 million decrease in total sales, net of blending and other expense. The impact of lower pricing was partially offset by higher production, which contributed to a $56.1 million increase in total sales, net of blending and other expense, relative to Q1/2022.

In the U.S., total petroleum and natural gas sales of $169.7 million for Q1/2023 decreased $50.4 million from $220.1 million reported for Q1/2022. Total petroleum and natural gas sales decreased $39.4 million due to lower realized pricing and $11.0 million from lower production in Q1/2023 relative to Q1/2022.

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, 2023 and 2022.

	Three Months Ended March 31					
	2023			2022		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 43,855**	**$ 49,398**	**$ 93,253**	$ 57,676	$ 65,044	$ 122,720
Average royalty rate (1)(2)	**13.5 %**	**29.1 %**	**18.8 %**	14.0 %	29.5 %	19.4 %
Royalties per boe (3)	**$ 8.03**	**$ 21.02**	**$ 11.94**	$ 12.00	$ 26.30	$ 16.86

(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 Q1/2023 were $93.3 million or 18.8% of total sales, net of blending and other expense, compared to $122.7 million or 19.4% for Q1/2022. Royalties were lower for Q1/2023 due to lower total sales, net of blending and other expense, relative to Q1/2022. Our average royalty rate of 18.8% for Q1/2023 was lower than 19.4% for Q1/2022 due to our heavy oil production growth which caused a higher proportion of our production being generated in Canada. Our average royalty rate of 18.8% for Q1/2023 is near the low end of our annual guidance range of 20.0% - 22.0% for 2023 which reflects lower realized heavy oil pricing in Q1/2023.

Our average royalty rate in Canada of 13.5% for Q1/2023 was slightly lower than 14.0% for Q1/2022 as a result of lower benchmark commodity prices. In the U.S., royalties averaged 29.1% of total sales for Q1/2023, which is consistent with 29.5% for Q1/2022 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

OPERATING EXPENSE

	Three Months Ended March 31					
	2023			2022		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 91,180**	**$ 21,228**	**$ 112,408**	$ 78,540	$ 22,226	$ 100,766
Operating expense per boe [1]	**$ 16.70**	**$ 9.03**	**$ 14.40**	$ 16.35	$ 8.99	$ 13.85

(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 $112.4 million ($14.40/boe) for Q1/2023 compared to $100.8 million ($13.85/boe) for Q1/2022. The increase in total operating expenses is primarily due to higher production in Q1/2023 relative to Q1/2022. Our per unit operating expense was slightly higher in Q1/2023 due to a greater proportion of our production being generated in Canada relative to Q1/2022. Per unit operating expense of $14.40/boe for Q1/2023 was consistent with our annual guidance range of $14.00 - $14.75/boe for 2023.

In Canada, total operating expense was $91.2 million ($16.70/boe) for Q1/2023 which was higher than $78.5 million ($16.35/boe) for Q1/2022 due to higher production as our per unit operating expense was relatively consistent in both periods. In the U.S., operating expense was $21.2 million ($9.03/boe or US$6.68/boe expressed in U.S. dollars) for Q1/2023 and was fairly consistent with $22.2 million ($8.99/boe or US$7.10/boe expressed in U.S. dollars) for Q1/2022.

TRANSPORTATION EXPENSE

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of oil in Canada to pipeline and rail terminals which can vary from period to period depending on hauling distances as we seek to optimize sales prices and trucking rates.

The following table compares our transportation expense for the three months ended March 31, 2023 and 2022.

	Three Months Ended March 31					
	2023			2022		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 17,005**	**$ —**	**$ 17,005**	$ 9,215	$ —	$ 9,215
Transportation expense per boe [1]	**$ 3.12**	**$ —**	**$ 2.18**	$ 1.92	$ —	$ 1.27

(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 $17.0 million ($2.18/boe) for Q1/2023 compared to $9.2 million ($1.27/boe) for Q1/2022. Total transportation expense and per unit costs were higher in Q1/2023 as a result of additional heavy oil production in Canada along with higher trucking rates relative to Q1/2022. Per unit transportation expense of $2.18/boe for Q1/2023 is consistent with expectations and is marginally higher than our annual guidance range of $1.90 - $2.10/boe for 2023.

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 $59.7 million for Q1/2023 compared to $41.4 million for Q1/2022. Higher blending and other expense is primarily a result of higher heavy oil production and pipeline shipments in Q1/2023 relative to Q1/2022.

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, 2023 and 2022.

	Three Months Ended March 31		
($ thousands)	**2023**	2022	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ 5,415**	$ (79,526)	$ 84,941
Natural gas	**—**	(4,840)	4,840
Total	**$ 5,415**	$ (84,366)	$ 89,781
Unrealized financial derivatives gain (loss)			
Crude oil	**$ 9,210**	$ (139,318)	$ 148,528
Natural gas	**—**	(16,634)	16,634
Equity total return swap ("Equity TRS")	**—**	(309)	309
Total	**$ 9,210**	$ (156,261)	$ 165,471
Total financial derivatives gain (loss)			
Crude oil	**$ 14,625**	$ (218,844)	$ 233,469
Natural gas	**—**	(21,474)	21,474
Equity TRS	**—**	(309)	309
Total	**$ 14,625**	$ (240,627)	$ 255,252

We recorded a total financial derivative gain of $14.6 million for Q1/2023 compared to a loss of $240.6 million for Q1/2022. The realized financial derivatives gain of $5.4 million for Q1/2023 was primarily a result of the market prices for crude oil settling at levels below those set in our derivative contracts. The unrealized gain of $9.2 million for Q1/2023 reflects changes in forecasted crude oil pricing used to revalue the unsettled notional volume on our crude oil contracts in place at March 31, 2023 relative to December 31, 2022. The fair value of our financial derivative contracts resulted in a net asset of $19.3 million at March 31, 2023 compared to a net asset of $10.1 million at December 31, 2022.

We had the following commodity financial derivative contracts as at May 4, 2023.

	Remaining Period	Volume	Price/Unit (1)	Index
Oil				
Basis differential (2)	May 2023 to Dec 2023	1,500 bbl/d	Baytex pays: MSW Baytex receives: WTI less US$2.50/bbl	MSW
Basis differential (2)	May 2023 to Dec 2023	5,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.10/bbl	WCS
Collar (3)(4)	May 2023 to Dec 2023	14,500 bbl/d	US$60.00/US$100.00	WTI
Put option (4)	May 2023 to Dec 2023	5,000 bbl/d	US$60.00	WTI

(1) Based on the weighted average price per unit for the period.
(2) Contracts that fix the basis differential between certain oil reference prices.
(3) As of March 31, 2023, Baytex had 3-way option contracts with a total volume of 9,500 bbl/d with an average sold put price of US$61.58/bbl, an average bought put price of US$78.37/bbl and an average sold call price of US$96.12/bbl along with a 5,000 bbl/d collar contract with a bought put price of US$60.00/bbl and sold call price US$94.00/bbl. On May 3, 2023 the Company restructured these hedges into a collar with a bought put price of US$60.00/bbl and sold call price US$100.00/bbl and received US$11.3 million.
(4) Contract entered subsequent to March 31, 2023.

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, 2023 and 2022.

	Three Months Ended March 31					
	2023			2022		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**60,651**	**26,109**	**86,760**	53,385	27,482	80,867
Operating netback:						
Total sales, net of blending and other expense (1)	**$ 59.71**	**$ 72.22**	**$ 63.48**	$ 85.81	$ 89.00	$ 86.89
Less:						
Royalties (2)	**(8.03)**	**(21.02)**	**(11.94)**	(12.00)	(26.30)	(16.86)
Operating expense (2)	**(16.70)**	**(9.03)**	**(14.40)**	(16.35)	(8.99)	(13.85)
Transportation expense (2)	**(3.12)**	**—**	**(2.18)**	(1.92)	—	(1.27)
Operating netback (1)	**$ 31.86**	**$ 42.17**	**$ 34.96**	$ 55.54	$ 53.71	$ 54.91
Realized financial derivatives gain (loss) (3)	**—**	**—**	**0.69**	—	—	(11.59)
Operating netback after financial derivatives (1)	**$ 31.86**	**$ 42.17**	**$ 35.65**	$ 55.54	$ 53.71	$ 43.32

(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 $34.96/boe for Q1/2023 was lower than $54.91/boe for Q1/2022 due to decreases in benchmark pricing which resulted in lower per unit sales net of royalties during Q1/2023 relative to Q1/2022. Total operating and transportation expense of $16.58/boe for Q1/2023 was higher than $15.12/boe for Q1/2022 due to increases in trucking rates period over period. Our operating netback net of realized gains and losses on financial derivatives was $35.65/boe for Q1/2023 compared to $43.32/boe for Q1/2022.

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, 2023 and 2022.

	Three Months Ended March 31		
($ thousands except for per boe)	**2023**	2022	Change
Gross general and administrative expense	**$ 14,416**	$ 13,507	$ 909
Overhead recoveries	**(2,682)**	(1,825)	(857)
General and administrative expense	**$ 11,734**	$ 11,682	$ 52
General and administrative expense per boe (1)	**$ 1.50**	$ 1.61	$ (0.11)

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

G&A expense was $11.7 million ($1.50/boe) for Q1/2023 which is consistent with $11.7 million ($1.61/boe) for Q1/2022. Gross G&A increased $0.9 million in Q1/2023 from Q1/2022 which reflects the impacts of inflation and was offset by higher overhead recoveries from additional exploration and development expenditures in Q1/2023. G&A expense of $1.50/boe for Q1/2023 is slightly below our 2023 annual guidance of $1.63/boe as Q1/2023 reflects higher overhead recoveries from our active exploration and development.

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, 2023 and 2022.

	Three Months Ended March 31		
($ thousands except for per boe)	**2023**	2022	Change
Interest on credit facilities	**$ 6,216**	$ 3,039	$ 3,177
Interest on long-term notes	**12,094**	17,344	(5,250)
Interest on lease obligations	**65**	44	21
Cash interest	**$ 18,375**	$ 20,427	$ (2,052)
Accretion of debt issue costs	**524**	695	(171)
Accretion of asset retirement obligations	**4,826**	3,122	1,704
Financing and interest expense	**$ 23,725**	$ 24,244	$ (519)
Cash interest per boe (1)	**$ 2.35**	$ 2.81	$ (0.46)
Financing and interest expense per boe (1)	**$ 3.04**	$ 3.33	$ (0.29)

(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 $23.7 million ($3.04/boe) for Q1/2023 compared to $24.2 million ($3.33/boe) for Q1/2022.

Cash interest of $18.4 million ($2.35/boe) for Q1/2023 was lower than $20.4 million ($2.81/boe) for Q1/2022 and is primarily a result of decreased interest on our long-term notes following the repurchase and redemption of US$290.2 million of principal amount during 2022. The decrease in interest due to reduced long-term notes principal outstanding was partially offset by the increase in benchmark borrowing rates which resulted in higher interest on our credit facilities in Q1/2023 relative to Q1/2022. The weighted average interest rate applicable on our credit facilities was 6.0% for Q1/2023 compared to 2.4% for Q1/2022.

Accretion of asset retirement obligations of $4.8 million for Q1/2023 was higher than $3.1 million for Q1/2022 due to a higher discount rate used in Q1/2023.

Cash interest expense of $2.35/boe for Q1/2023 is higher than our 2023 annual guidance of $2.04/boe which is consistent with expectations as we expect to reduce debt and increase production throughout the remainder of 2023.

EXPLORATION AND EVALUATION EXPENSE

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense was $0.2 million for Q1/2023 compared to $3.6 million for Q1/2022.

DEPLETION AND DEPRECIATION

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved plus 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, 2023 and 2022.

	Three Months Ended March 31		
($ thousands except for per boe)	**2023**	2022	Change
Depletion	**$ 164,435**	$ 139,446	$ 24,989
Depreciation	**1,564**	1,345	219
Depletion and depreciation	**$ 165,999**	$ 140,791	$ 25,208
Depletion and depreciation per boe (1)	**$ 21.26**	$ 19.34	$ 1.92

(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 $166.0 million ($21.26/boe) for Q1/2023 compared to $140.8 million ($19.34/boe) for Q1/2022. Total depletion and depreciation expense and depletion and depreciation per boe were higher in Q1/2023 relative to Q1/2022 as a result of the $245.2 million impairment reversal that was recorded at December 31, 2022 and the increase in future development costs attributed to proved plus probable reserves which resulted in a higher depletable base for our Canadian oil and gas properties as at March 31, 2023.

IMPAIRMENT

We did not identify indicators of impairment or impairment reversal for any of our cash generating units ("CGUs") at March 31, 2023.

2022 Impairment Reversal

At December 31, 2022, we identified indicators of impairment reversal for oil and gas properties in five of our six CGUs due to the increase in forecasted commodity prices in addition to changes in proved plus probable reserves, which resulted in an impairment reversal of $245.2 million. At December 31, 2022, we identified indicators of impairment reversal for E&E assets in the Peace River CGU due to an increase in land sale values and recorded an impairment reversal of $22.5 million. The total impairment reversal recorded at December 31, 2022 was $267.7 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 financial liability included in trade and other payables, and includes gains or losses on equity total return swaps. The liability is re-measured at each reporting date and results in either a SBC expense or recovery based on changes in our share price.

We recorded SBC expense of $9.8 million for Q1/2023 which is higher than $3.9 million for Q1/2022 as we received Board approval for the application of a 1.5x performance factor for 2022 that was applied to performance awards at Q1/2023. The total expense for Q1/2023 is considered cash compensation as we expect all future awards to be settled in cash while the Company is repurchasing shares as part of its shareholder return program. SBC expense of $3.9 million recorded in Q1/2022 was comprised of $2.2 million cash compensation expense and $1.7 million non-cash compensation expense.

In Q1/2023 we reduced the notional amount of the equity total return swaps to match the number of awards outstanding under the Deferred Share Unit Plan where we previously had targeted an amount equivalent to approximately 90-100% of all cash settled awards outstanding, including incentive awards and certain awards outstanding under the Share Award Incentive Plan.

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.

($ thousands except for exchange rates)	Three Months Ended March 31 2023	2022	Change
Unrealized foreign exchange gain	$ **(213)**	$ (14,548)	$ 14,335
Realized foreign exchange loss	**150**	203	(53)
Foreign exchange gain	$ **(63)**	$ (14,345)	$ 14,282
CAD/USD exchange rates:			
At beginning of period	**1.3534**	1.2656	
At end of period	**1.3528**	1.2484	

We recorded a foreign exchange gain of $0.1 million for Q1/2023 compared to a gain of $14.3 million for Q1/2022.

The unrealized foreign exchange gain of $0.2 million for Q1/2023 is related to changes in the reported amount of our long-term notes and credit facilities and reflects a CAD/USD exchange rate of 1.3534 at March 31, 2023 which is consistent with 1.3528 at December 31, 2022. The unrealized foreign exchange gain of $14.5 million for Q1/2022 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, 2022 compared to December 31, 2021.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange loss of $0.2 million for Q1/2023 which is consistent with Q1/2022.

INCOME TAXES

($ thousands)	Three Months Ended March 31 2023	2022	Change
Current income tax expense	$ **1,120**	$ 910	$ 210
Deferred income tax expense (recovery)	**15,523**	(67,332)	82,855
Total income tax expense (recovery)	$ **16,643**	$ (66,422)	$ 83,065

Current income tax expense was $1.1 million for Q1/2023 compared to $0.9 million for Q1/2022.

We recorded deferred tax expense of $15.5 million for Q1/2023 compared to a recovery of $67.3 million for Q1/2022. The deferred tax expense recorded in Q1/2023 is the result of income generated for the period. The deferred tax recovery recorded in Q1/2022 was primarily related to the effect of an internal debt restructuring offset by the income generated in our U.S. operations for the period.

As disclosed in the 2021 annual financial statements, certain indirect subsidiaries received reassessments from the Canada Revenue Agency (the "CRA") that deny $591.0 million of non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. In September 2016, we filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to our file in July 2018. We remain confident that our original tax filings are correct and intend to defend these tax filings through the appeals process.

NET INCOME AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income for the three months ended March 31, 2023 and 2022 are set forth in the following table.

	Three Months Ended March 31		
($ thousands)	**2023**	2022	Change
Petroleum and natural gas sales	**$ 555,336**	$ 673,825	$ (118,489)
Royalties	**(93,253)**	(122,720)	29,467
Revenue, net of royalties	**462,083**	551,105	(89,022)
Expenses			
Operating	**(112,408)**	(100,766)	(11,642)
Transportation	**(17,005)**	(9,215)	(7,790)
Blending and other	**(59,681)**	(41,440)	(18,241)
Operating netback [1]	**$ 272,989**	$ 399,684	$ (126,695)
General and administrative	**(11,734)**	(11,682)	(52)
Cash interest	**(18,375)**	(20,427)	2,052
Realized financial derivatives gain (loss)	**5,415**	(84,366)	89,781
Realized foreign exchange loss	**(150)**	(203)	53
Other expense	**(213)**	(250)	37
Current income tax expense	**(1,120)**	(910)	(210)
Cash share-based compensation	**(9,823)**	(2,239)	(7,584)
Adjusted funds flow [2]	**$ 236,989**	$ 279,607	$ (42,618)
Transaction costs	**(8,871)**	—	(8,871)
Exploration and evaluation	**(163)**	(3,570)	3,407
Depletion and depreciation	**(165,999)**	(140,791)	(25,208)
Non-cash share-based compensation	**—**	(1,706)	1,706
Non-cash financing and interest	**(5,350)**	(3,817)	(1,533)
Non-cash other income	**1,271**	1,282	(11)
Unrealized financial derivatives gain (loss)	**9,210**	(156,261)	165,471
Unrealized foreign exchange gain	**213**	14,548	(14,335)
(Loss) gain on dispositions	**(336)**	234	(570)
Deferred income tax (expense) recovery	**(15,523)**	67,332	(82,855)
Net income	**$ 51,441**	$ 56,858	$ (5,417)

(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 $237.0 million for Q1/2023 compared to $279.6 million for Q1/2022. The decrease in adjusted funds flow was primarily due to lower operating netback in Q1/2023 which decreased $126.7 million relative to Q1/2022 as a result of lower commodity prices that decreased revenue, net of royalties. The decrease in operating netback was partially offset by the realized gain on financial derivatives of $5.4 million for Q1/2023 which increased $89.8 million relative to Q1/2022 when we recorded a realized loss on financial derivatives of $84.4 million. We reported net income of $51.4 million for Q1/2023 which is relatively consistent with $56.9 million reported for Q1/2022.

OTHER COMPREHENSIVE INCOME (LOSS)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets which is not recognized in net income or loss. The foreign currency translation loss of $0.5 million for Q1/2023 relates to the change in value of our U.S. net assets and reflects a CAD/USD exchange rate of 1.3528 CAD/USD as at March 31, 2023 which is consistent with 1.3534 CAD/USD at December 31, 2022.

CAPITAL EXPENDITURES

Capital expenditures for the three months ended March 31, 2023 and 2022 are summarized as follows.

	Three Months Ended March 31					
	2023			2022		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 154,953**	**$ 48,836**	**$ 203,789**	$ 107,000	$ 27,138	$ 134,138
Facilities	**16,985**	**—**	**16,985**	7,764	386	8,150
Land, seismic and other	**12,668**	**184**	**12,852**	11,366	168	11,534
Exploration and development expenditures	**$ 184,606**	**$ 49,020**	**$ 233,626**	$ 126,130	$ 27,692	$ 153,822
Property acquisitions	**$ 506**	**$ —**	**$ 506**	$ 59	$ —	$ 59
Proceeds from dispositions	**$ (235)**	**$ —**	**$ (235)**	$ (27)	$ —	$ (27)

Exploration and development expenditures were $233.6 million for Q1/2023 compared to $153.8 million for Q1/2022. Exploration and development expenditures in Q1/2023 were higher compared to Q1/2022 as a result of increased development activity along with inflationary pressures that resulted in higher costs relative to 2022.

In Canada, exploration and development expenditures were $184.6 million in Q1/2023 compared to $126.1 million in Q1/2022. Drilling and completion spending of $155.0 million in Q1/2023 reflects higher light and heavy oil development activity relative to Q1/2022 when we spent $107.0 million. We also invested $17.0 million on facilities and $12.7 million on land, seismic and other expenditures during Q1/2023.

Total U.S. exploration and development expenditures were $49.0 million for Q1/2023 compared to $27.7 million in Q1/2022. Exploration and development expenditures for Q1/2023 included costs associated with drilling 24 (6.5 net) wells along with 24 (6.4 net) wells brought on production compared to drilling 16 (2.5 net) wells along with 17 (4.8 net) wells brought on production during Q1/2022.

Exploration and development expenditures of $233.6 million for Q1/2023 were consistent with expectations as activity was planned to be weighted early in the year. Our annual guidance of $575 - $650 million reflects moderated activity levels over the remainder of 2023.

CAPITAL RESOURCES AND LIQUIDITY

Our objective for capital management is to maintain a flexible capital structure and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions. At March 31, 2023, our capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables, 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.

The capital intensive nature of our operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties.

Management of debt levels is a priority for Baytex in order to sustain operations and support our long-term plans. At March 31, 2023, net debt(1) of $995.2 million was consistent with $987.4 million at December 31, 2022 as approximately 40% of our planned 2023 annual exploration and development expenditures occurred during Q1/2023.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio calculated on a trailing twelve-month basis. At March 31, 2023, our net debt to adjusted funds flow ratio(1) was 0.9 compared to a ratio of 0.8 as at December 31, 2022. The increase in the net debt to adjusted funds flow ratio relative to December 31, 2022 is attributed to lower adjusted funds flow for the trailing twelve months ended March 31, 2023 compared to the twelve months ended December 31, 2022.

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

Credit Facilities

At March 31, 2023, we had $409.7 million of principal amount outstanding under our revolving credit facilities which total US$850 million and mature on April 1, 2026 (the "Credit Facilities"). The Credit Facilities are comprised of a US$50 million operating loan and a US$600 million syndicated revolving loan for Baytex and a US$10 million operating loan and a US$190 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc.

The Credit Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. 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 6.0% for Q1/2023 compared to 2.4% for Q1/2022. The interest rate on our Credit Facilities has increased with higher government benchmark rates in 2023 relative to the same period in 2022.

At March 31, 2023, Baytex had $15.7 million of outstanding letters of credit under a $20 million uncommitted unsecured demand revolving letter of credit facility (December 31, 2022 - $15.7 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.sedar.com.

In connection with the Merger Transaction, we have entered into credit facility commitments with a syndicate of banks to provide aggregate debt commitments of US$1.75 billion comprised of a US$1.0 billion revolving credit facility (an increase from the committed amount of US$850 million in aggregate as of April 1, 2022), a US$250 million two-year term loan and 364-day bridge loan facility in an aggregate principal amount of US$500 million (the "Bridge Loan"). The Bridge Loan was cancelled as of April 28, 2023. At closing of the merger with Ranger we expect to increase the capacity of the revolving credit facilities to US$1.1 billion. The amended agreement will contain an additional financial covenant of a maximum Total Debt[1] to EBITDA[2] ratio of 4.0:1.0.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Calculated in accordance with the Credit Facilities Agreement.

Financial Covenants

The following table summarizes the financial covenants applicable to the credit facilities and our compliance therewith at March 31, 2023.

Covenant Description	Position as at March 31, 2023	Covenant
Senior Secured Debt [1] to Bank EBITDA [2] (Maximum Ratio)	**0.3:1.0**	3.5:1.0
Interest Coverage [3] (Minimum Ratio)	**15.4:1.0**	2.0:1.0

(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, 2023, the Company's Senior Secured Debt totaled $409.7 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, 2023 was $1.2 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, 2023 was $78.1 million.

Long-Term Notes

We have one series of long-term notes outstanding with a total principal amount of $554.4 million as at March 31, 2023. 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.

On April 27, 2023, we closed a private offering of the US$800 million aggregate principal amount of senior unsecured notes due 2030 ("8.5% Senior Notes"). The 8.5% Senior Notes were priced at 98.709% of par and will bear interest at a rate of 8.5% per annum and mature on April 30, 2030. Proceeds from the 8.5% Senior Notes will initially be deposited into escrow and will be released at closing of the merger with Ranger and will be used, in part, to fund a portion of the costs and expenses for the merger with Ranger.

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, 2023, we issued 0.6 million common shares pursuant to our share-based compensation program. As at March 31, 2023, we had 545.6 million common shares issued and outstanding and no preferred shares issued and outstanding.

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, 2023 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
Trade and other payables	**$ 271,022**	$ 269,177	$ 1,845	$ —	$ —
Credit facilities - principal	**409,653**	—	—	409,653	—
Long-term notes - principal	**554,351**	—	—	554,351	—
Interest on long-term notes (1)	**194,288**	48,506	97,011	48,771	—
Lease obligations - principal	**8,570**	4,914	3,336	320	—
Processing agreements	**6,093**	941	1,051	698	3,403
Transportation agreements	**188,698**	39,293	76,525	65,349	7,531
Total	**$ 1,632,675**	$ 362,831	$ 179,768	$ 1,079,142	$ 10,934

(1) Excludes interest on our credit facilities as interest payments fluctuate based on a floating rate of interest and changes in the outstanding balances.

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities when they reach the end of their economic lives. Programs to abandon and reclaim well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

QUARTERLY FINANCIAL INFORMATION

	2023	2022				2021		
($ thousands, except per common share amounts)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Petroleum and natural gas sales	**555,336**	648,986	712,065	854,169	673,825	552,403	488,736	442,354
Net income	**51,441**	352,807	264,968	180,972	56,858	563,239	32,713	1,052,999
Per common share - basic	**0.09**	0.65	0.48	0.32	0.10	1.00	0.06	1.87
Per common share - diluted	**0.09**	0.64	0.47	0.32	0.10	0.98	0.06	1.85
Adjusted funds flow (1)	**236,989**	255,552	284,288	345,704	279,607	214,766	198,397	175,883
Per common share - basic	**0.43**	0.47	0.51	0.61	0.49	0.38	0.35	0.31
Per common share - diluted	**0.43**	0.46	0.51	0.60	0.49	0.37	0.35	0.31
Free cash flow (2)	**(1,918)**	143,324	111,568	245,316	121,318	137,133	101,215	112,486
Per common share - basic	**—**	0.26	0.20	0.43	0.21	0.24	0.18	0.20
Per common share - diluted	**—**	0.26	0.20	0.43	0.21	0.24	0.18	0.20
Cash flows from operating activities	**184,938**	303,441	310,423	360,034	198,974	240,567	178,961	171,876
Per common share - basic	**0.34**	0.56	0.56	0.63	0.35	0.43	0.32	0.30
Per common share - diluted	**0.34**	0.55	0.56	0.63	0.35	0.42	0.31	0.30
Exploration and development	**233,626**	103,634	167,453	96,633	153,822	73,995	94,235	61,485
Canada	**184,606**	85,641	117,150	51,881	126,130	59,821	75,499	30,387
U.S.	**49,020**	17,993	50,303	44,752	27,692	14,174	18,736	31,098
Property acquisitions	**506**	1,085	—	208	59	1,443	89	—
Proceeds from dispositions	**(235)**	(148)	(25,460)	(14)	(27)	(6,857)	(701)	(18)
Net debt (1)	**995,170**	987,446	1,113,559	1,123,297	1,275,680	1,409,717	1,564,658	1,629,629
Total assets	**5,180,059**	5,103,769	4,923,617	4,870,432	4,917,811	4,834,643	4,453,971	4,438,162
Common shares outstanding	**545,553**	544,930	547,615	560,139	569,214	564,213	564,213	564,182
Daily production								
Total production (boe/d)	**86,760**	86,864	83,194	83,090	80,867	80,789	79,872	81,162
Canada (boe/d)	**60,651**	56,946	55,803	54,919	53,385	50,362	48,124	47,205
U.S. (boe/d)	**26,109**	29,918	27,391	28,170	27,482	30,428	31,748	33,957
Benchmark prices								
WTI oil (US$/bbl)	**76.13**	82.64	91.56	108.41	94.29	77.19	70.56	66.07
WCS heavy oil ($/bbl)	**69.44**	77.37	93.62	122.05	100.99	78.82	71.81	67.03
Edmonton par oil ($/bbl)	**99.04**	109.57	116.79	137.79	115.66	93.29	83.78	77.28
CAD/USD avg exchange rate	**1.3520**	1.3577	1.3059	1.2766	1.2661	1.2600	1.2601	1.2279
AECO natural gas ($/mcf)	**4.34**	5.58	5.81	6.27	4.59	4.94	3.54	2.85
NYMEX natural gas (US$/mmbtu)	**3.42**	6.26	8.20	7.17	4.95	5.83	4.01	2.83
Total sales, net of blending and other expense ($/boe) (2)	**63.48**	74.93	87.68	105.44	86.89	70.42	63.85	57.19
Royalties ($/boe) (3)	**(11.94)**	(15.23)	(19.21)	(22.69)	(16.86)	(13.47)	(12.32)	(11.04)
Operating expense ($/boe) (3)	**(14.40)**	(13.06)	(14.39)	(14.21)	(13.85)	(12.83)	(11.46)	(11.22)
Transportation expense ($/boe) (3)	**(2.18)**	(1.85)	(1.67)	(1.56)	(1.27)	(1.10)	(1.06)	(1.01)
Operating netback ($/boe) (2)	**34.96**	44.79	52.41	66.98	54.91	43.02	39.01	33.92
Financial derivatives (loss) gain ($/boe) (3)	**0.69**	(6.21)	(9.98)	(16.41)	(11.59)	(9.49)	(7.34)	(5.28)
Operating netback after financial derivatives ($/boe) (2)	**35.65**	38.58	42.43	50.57	43.32	33.53	31.67	28.64

(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 strengthened. Production steadily increased from 81,162 boe/d in Q2/2021 to 86,760 boe/d in Q1/2023 as a result of strong well performance and increased development activity as commodity prices improved.

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. Our realized price of $63.48/boe for Q1/2023 reflects recent declines in crude oil prices caused by concern over future demand and economic slowdowns.

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 $237.0 million for Q1/2023 reflects strong production results from our development plans in the U.S. and Canada.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt(1) decreased from $1.6 billion at Q2/2021 to $995.2 million at Q1/2023 as free cash flow(2) of $970.4 million generated over the last eight quarters has been primarily directed towards debt repayment. The decrease in net debt is partially offset by $159.0 million in shareholder returns and an increase in the CAD/USD exchange rate.

(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, 2022 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, 2022, 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 we may be subject to additional future disclosure requirements. The International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. 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. We continue to monitor developments on these reporting requirements and have 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, 2023, 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, 2023. 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, 2022.

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", "total debt", "net debt" and "net debt to adjusted funds flow ratio" which are capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

Non-GAAP Financial Measures

Total sales, net of blending and other expense and heavy oil, net of blending and other expense

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

The following table reconciles heavy oil, net of blending and other expense to amounts disclosed in the primary financial statements in the following table.

	Three Months Ended March 31	
($ thousands)	**2023**	2022
Petroleum and natural gas sales	**$ 555,336**	$ 673,825
Light oil and condensate [1]	**(288,467)**	(360,976)
NGL [1]	**(21,833)**	(29,490)
Natural gas sales [1]	**(27,951)**	(38,920)
Heavy oil sales	**$ 217,085**	$ 244,439
Blending and other expense [2]	**(59,681)**	(41,440)
Heavy oil, net of blending and other expense	**$ 157,404**	$ 202,999

(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, 2023 for further information.
(2) The portion of blending and other expense that relates to heavy oil sales for the applicable period.

Operating netback

Operating netback and operating netback after financial derivatives are used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

The following table reconciles operating netback and operating netback after realized financial derivatives to petroleum and natural gas sales.

	Three Months Ended March 31	
($ thousands)	**2023**	2022
Petroleum and natural gas sales	**$ 555,336**	$ 673,825
Blending and other expense	**(59,681)**	(41,440)
Total sales, net of blending and other expense	**$ 495,655**	$ 632,385
Royalties	**(93,253)**	(122,720)
Operating expense	**(112,408)**	(100,766)
Transportation expense	**(17,005)**	(9,215)
Operating netback	**$ 272,989**	$ 399,684
Realized financial derivatives gain (loss) [1]	**5,415**	(84,366)
Operating netback after realized financial derivatives	**$ 278,404**	$ 315,318

(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, 2023 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 March 31	
($ thousands)	2023	2022
Cash flows from operating activities	$ 184,938	$ 198,974
Change in non-cash working capital	39,054	77,340
Additions to exploration and evaluation assets	(490)	(3,559)
Additions to oil and gas properties	(233,136)	(150,263)
Payments on lease obligations	(1,155)	(1,174)
Transaction costs	8,871	—
Free cash flow	$ (1,918)	$ 121,318

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

Total debt and Net debt

We use total debt and net debt to monitor our current financial position and to evaluate existing sources of liquidity. We define total debt to be the sum of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs. To arrive at net debt, we then adjust for trade and other payables, cash, and trade and other receivables. We also use total debt and net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. We also use a net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis to monitor our existing capital structure and future liquidity requirements. Net debt to adjusted funds flow is comprised of net debt divided by twelve-month trailing adjusted funds flow.

The following table summarizes our calculation of total debt and net debt.

($ thousands)		March 31, 2023		December 31, 2022
Credit facilities	**$**	**407,473**	$	383,031
Unamortized debt issuance costs - Credit facilities (1)		**2,180**		2,363
Long-term notes		**547,698**		547,598
Unamortized debt issuance costs - Long-term notes (1)		**6,653**		6,999
Total debt	**$**	**964,004**	$	939,991
Trade and other payables		**271,022**		281,404
Cash		**(6,445)**		(5,464)
Trade and other receivables		**(233,411)**		(228,485)
Net debt	**$**	**995,170**	$	987,446
Net debt to adjusted funds flow		**0.9**		0.8

(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, 2023. 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 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 during the applicable period, and transaction costs.

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

	Three Months Ended March 31			
($ thousands)		2023		2022
Cash flow from operating activities	**$**	**184,938**	$	198,974
Change in non-cash working capital		**39,054**		77,340
Asset retirement obligations settled		**4,126**		3,293
Transaction costs		**8,871**		—
Adjusted funds flow	**$**	**236,989**	$	279,607

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, 2023.

FORWARD-LOOKING STATEMENTS

In the interest of providing our shareholders and potential investors with information regarding Baytex, including management's assessment of the Company's future plans and operations, certain statements in this document are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "plan", "project", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to but not limited to: that the Merger Transaction creates a more resilient and sustainable business with higher revenues, improved margins and enhanced inventory which will allow for a more robust shareholder return framework; that following the Merger Transaction we intend to increase direct shareholder returns to 50% of free cash flow, including implementation of a quarterly dividend of $0.0225 per share ($0.09 per share annualized) and the timing thereof; the expected closing date of the Merger Transaction; our 2023 guidance on a stand-alone basis (excluding Ranger) with respect to exploration and development expenditures, average daily production, royalty rate and operating, transportation, general and administrative and interest expenses; the existence, operation and strategy of our risk management program; that we expect to cash settle share awards; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; the manner in which we fund our planned capital expenditures and monitor and manage our capital resources and liquidity; that we may issue debt or equity securities, sell assets or adjust capital spending; and the expected composition of our credit facilities on closing of the Merger Transaction.

These forward-looking statements are based on certain key assumptions regarding, among other things: the consummation and success of the Merger Transaction and our ability to successfully integrate the acquired business into our existing operations; the timing of receipt of regulatory and shareholder and stockholder approvals; the ability of the combined business to realize the anticipated benefits of the transaction; petroleum and natural gas prices and differentials between light, medium and heavy 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; 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 ability to obtain stockholder, shareholder, and regulatory approvals, if any, of the Merger Transaction; the ability to complete the Merger Transaction on anticipated terms and timetable; the possibility that various closing conditions for the transaction may not be satisfied or waived; risks relating to any unforeseen liabilities of Baytex and Ranger; the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; 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 of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; 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, 2022, as 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.

Dividend Advisory

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. There can be no assurance that Baytex will pay dividends following closing of the Merger Transaction.

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

	Notes	As at March 31, 2023	As at December 31, 2022
ASSETS			
Current assets			
Cash		**$ 6,445**	$ 5,464
Trade and other receivables		**233,411**	228,485
Financial derivatives	17	**19,315**	10,105
		259,171	244,054
Non-current assets			
Exploration and evaluation assets	5	**165,958**	168,684
Oil and gas properties	6	**4,685,902**	4,620,766
Other plant and equipment		**6,646**	6,568
Lease assets		**8,164**	6,453
Deferred income tax asset	14	**54,218**	57,244
		$ 5,180,059	$ 5,103,769
LIABILITIES			
Current liabilities			
Trade and other payables		**$ 269,177**	$ 272,195
Lease obligations		**4,699**	3,521
Asset retirement obligations	9	**12,884**	12,813
		286,760	288,529
Non-current liabilities			
Trade and other payables		**1,845**	9,209
Credit facilities	7	**407,473**	383,031
Long-term notes	8	**547,698**	547,598
Lease obligations		**3,596**	3,017
Asset retirement obligations	9	**569,810**	576,110
Deferred income tax liability	14	**278,146**	265,858
		2,095,328	2,073,352
SHAREHOLDERS' EQUITY			
Shareholders' capital	10	**5,503,085**	5,499,664
Contributed surplus		**89,879**	89,879
Accumulated other comprehensive income		**755,647**	756,195
Deficit		**(3,263,880)**	(3,315,321)
		3,084,731	3,030,417
		$ 5,180,059	$ 5,103,769

Subsequent event (note 3 and note 17)

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended March 31	
	Notes	2023	2022
Revenue, net of royalties			
Petroleum and natural gas sales	13	$ 555,336	$ 673,825
Royalties		(93,253)	(122,720)
		462,083	551,105
Expenses			
Operating		112,408	100,766
Transportation		17,005	9,215
Blending and other		59,681	41,440
General and administrative		11,734	11,682
Transaction costs	3	8,871	—
Exploration and evaluation	5	163	3,570
Depletion and depreciation		165,999	140,791
Share-based compensation	11	9,823	3,945
Financing and interest	15	23,725	24,244
Financial derivatives (gain) loss	17	(14,625)	240,627
Foreign exchange gain	16	(63)	(14,345)
Loss (gain) on dispositions		336	(234)
Other income		(1,058)	(1,032)
		393,999	560,669
Net income (loss) before income taxes		68,084	(9,564)
Income tax expense (recovery)	14		
Current income tax expense		1,120	910
Deferred income tax expense (recovery)		15,523	(67,332)
		16,643	(66,422)
Net income		$ 51,441	$ 56,858
Other comprehensive loss			
Foreign currency translation adjustment		(548)	(28,079)
Comprehensive income		$ 50,893	$ 28,779
Net income per common share	12		
Basic		$ 0.09	$ 0.10
Diluted		$ 0.09	$ 0.10
Weighted average common shares (000's)	12		
Basic		545,062	565,518
Diluted		548,078	569,705

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, 2021		$ 5,736,593	$ 13,559	$ 632,103	$ (4,170,926)	**$ 2,211,329**
Vesting of share awards		8,429	(8,429)	—	—	**—**
Share-based compensation		—	1,706	—	—	**1,706**
Comprehensive income (loss)		—	—	(28,079)	56,858	**28,779**
Balance at March 31, 2022		$ 5,745,022	$ 6,836	$ 604,024	$ (4,114,068)	**$ 2,241,814**
Balance at December 31, 2022		$ 5,499,664	$ 89,879	$ 756,195	$ (3,315,321)	**$ 3,030,417**
Vesting of share awards	10	3,421	—	—	—	**3,421**
Share-based compensation	11	—	—	—	—	**—**
Comprehensive income (loss)		—	—	(548)	51,441	**50,893**
Balance at March 31, 2023		$ 5,503,085	$ 89,879	$ 755,647	$ (3,263,880)	**$ 3,084,731**

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended March 31	
	Notes	**2023**	2022
CASH PROVIDED BY (USED IN):			
Operating activities			
Net income		**$ 51,441**	$ 56,858
Adjustments for:			
Non-cash share-based compensation	11	**—**	1,706
Unrealized foreign exchange gain	16	**(213)**	(14,548)
Exploration and evaluation	5	**163**	3,570
Depletion and depreciation		**165,999**	140,791
Non-cash financing and interest	15	**5,350**	3,817
Non-cash other income	9	**(1,271)**	(1,282)
Unrealized financial derivatives (gain) loss	17	**(9,210)**	156,261
Loss (gain) on dispositions		**336**	(234)
Deferred income tax expense (recovery)	14	**15,523**	(67,332)
Asset retirement obligations settled	9	**(4,126)**	(3,293)
Change in non-cash working capital		**(39,054)**	(77,340)
Cash flows from operating activities		**184,938**	198,974
Financing activities			
Increase (decrease) in credit facilities		**24,551**	(78,142)
Payments on lease obligations		**(1,155)**	(1,174)
Cash flows from (used in) financing activities		**23,396**	(79,316)
Investing activities			
Additions to exploration and evaluation assets	5	**(490)**	(3,559)
Additions to oil and gas properties	6	**(233,136)**	(150,263)
Additions to other plant and equipment		**(441)**	(374)
Property acquisitions		**(506)**	(59)
Proceeds from dispositions		**235**	27
Change in non-cash working capital		**26,985**	34,570
Cash flows used in investing activities		**(207,353)**	(119,658)
Change in cash		**981**	—
Cash, beginning of period		**5,464**	—
Cash, end of period		**$ 6,445**	$ —
Supplementary information			
Interest paid		**$ 30,469**	$ 30,348
Income taxes paid		**$ —**	$ —

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 the state of Texas in the 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 PRESENTATION

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, 2022.

The consolidated financial statements were approved by the Board of Directors of Baytex on May 4, 2023.

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

The audited consolidated financial statements of the Company as at and for the year ended December 31, 2022 are available through its filings on SEDAR at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov.

Estimation Uncertainty

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

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 has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. 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.

Significant Accounting Policies

The accounting policies, critical accounting judgments and significant estimates used in these consolidated financial statements are consistent with those used in the preparation of the 2022 annual financial statements.

3. PROPOSED BUSINESS COMBINATION

On February 28, 2023, Baytex announced that it has entered into a definitive agreement (the "Agreement") to acquire Ranger Oil Corporation ("Ranger"), an oil and gas exploration and production company with operations in the Eagle Ford (the "Merger Transaction"). The Merger Transaction has been unanimously approved by the Boards of Directors of Baytex and Ranger and is expected to close in the second quarter of 2023, subject to approval by the shareholders of both companies and the satisfaction of other customary closing conditions.

The Agreement provides that, upon the occurrence of certain termination events, either of the parties may be required to pay the other party their respective termination fees, being the Ranger termination fee of US$60 million and the Baytex termination fee of US$100 million.

The Merger Transaction will be funded with a combination of cash and shares. Baytex will issue 7.49 common shares for each Ranger share and pay US$13.31 per Ranger share along with assuming Ranger's net debt. The cash portion of the transaction will be funded with Baytex's expanded credit facility which will increase to US$1.1 billion upon the closing of the transaction, up to US$250 million from a two-year term loan facility, and the proceeds from the issuance of US$800 million senior unsecured notes due 2030. Baytex closed the US$800 million principal amount senior unsecured note offering on April 27, 2023 with the proceeds deposited into escrow subject to completion of the Merger Transaction.

During the three months ended March 31, 2023, Baytex incurred $8.9 million of transaction costs, including consulting, financial advisory, legal and filing fees related to the Merger Transaction.

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	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 385,622**	$ 453,704	**$ 169,714**	$ 220,121	**$ —**	$ —	**$ 555,336**	$ 673,825
Royalties	**(43,855)**	(57,676)	**(49,398)**	(65,044)	**—**	—	**(93,253)**	(122,720)
	341,767	396,028	**120,316**	155,077	**—**	—	**462,083**	551,105
Expenses								
Operating	**91,180**	78,540	**21,228**	22,226	**—**	—	**112,408**	100,766
Transportation	**17,005**	9,215	**—**	—	**—**	—	**17,005**	9,215
Blending and other	**59,681**	41,440	**—**	—	**—**	—	**59,681**	41,440
General and administrative	**—**	—	**—**	—	**11,734**	11,682	**11,734**	11,682
Transaction costs	**—**	—	**—**	—	**8,871**	—	**8,871**	—
Exploration and evaluation	**163**	3,570	**—**	—	**—**	—	**163**	3,570
Depletion and depreciation	**119,471**	101,082	**44,964**	38,364	**1,564**	1,345	**165,999**	140,791
Share-based compensation	**—**	—	**—**	—	**9,823**	3,945	**9,823**	3,945
Financing and interest	**—**	—	**—**	—	**23,725**	24,244	**23,725**	24,244
Financial derivatives (gain) loss	**—**	—	**—**	—	**(14,625)**	240,627	**(14,625)**	240,627
Foreign exchange gain	**—**	—	**—**	—	**(63)**	(14,345)	**(63)**	(14,345)
Loss (gain) on dispositions	**336**	(234)	**—**	—	**—**	—	**336**	(234)
Other (income) expense	**(1,271)**	(1,282)	**—**	—	**213**	250	**(1,058)**	(1,032)
	286,565	232,331	**66,192**	60,590	**41,242**	267,748	**393,999**	560,669
Net income (loss) before income taxes	**55,202**	163,697	**54,124**	94,487	**(41,242)**	(267,748)	**68,084**	(9,564)
Income tax expense (recovery)								
Current income tax expense							**1,120**	910
Deferred income tax expense (recovery)							**15,523**	(67,332)
							16,643	(66,422)
Net income (loss)	**$ 55,202**	$ 163,697	**$ 54,124**	$ 94,487	**$ (41,242)**	$ (267,748)	**$ 51,441**	$ 56,858
Additions to exploration and evaluation assets	**490**	3,559	**—**	—	**—**	—	**490**	3,559
Additions to oil and gas properties	**184,116**	122,571	**49,020**	27,692	**—**	—	**233,136**	150,263
Property acquisitions	**506**	59	**—**	—	**—**	—	**506**	59
Proceeds from dispositions	**(235)**	(27)	**—**	—	**—**	—	**(235)**	(27)

	March 31, 2023	December 31, 2022
Canadian assets	$ **2,839,330**	$ 2,779,596
U.S. assets	**2,306,604**	2,301,047
Corporate assets	**34,125**	23,126
Total consolidated assets	$ **5,180,059**	$ 5,103,769

5. EXPLORATION AND EVALUATION ASSETS

	March 31, 2023	December 31, 2022
Balance, beginning of period	$ **168,684**	$ 172,824
Capital expenditures	**490**	6,359
Property acquisitions	**506**	301
Divestitures	**(788)**	(498)
Property swaps	**978**	385
Impairment reversal	**—**	22,503
Exploration and evaluation expense	**(163)**	(30,239)
Transfer to oil and gas properties (note 6)	**(3,712)**	(8,496)
Foreign currency translation	**(37)**	5,545
Balance, end of period	$ **165,958**	$ 168,684

At March 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").

At December 31, 2022, the Company identified indicators of impairment reversal for the exploration and evaluation assets within the Peace River CGU due to an increase in land sale values. The recoverable amount for the Peace River CGU exceeded its carrying value and an impairment reversal of $22.5 million was recorded at December 31, 2022. The recoverable amount was based on the CGU's fair value less costs of disposal ("FVLCD") and was estimated with reference to arm's length transactions in comparable locations and the discounted cash flows associated with the Company's future development plans.

6. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2021	$ **11,633,517**	$ **(7,169,146)**	$ **4,464,371**
Capital expenditures	515,183	—	515,183
Property acquisitions	1,173	—	1,173
Transfers from exploration and evaluation assets (note 5)	8,496	—	8,496
Change in asset retirement obligations (note 9)	(147,020)	—	(147,020)
Divestitures	(265,166)	241,892	(23,274)
Impairment reversal	—	245,241	245,241
Foreign currency translation	296,033	(158,404)	137,629
Depletion	—	(581,033)	(581,033)
Balance, December 31, 2022	$ **12,042,216**	$ **(7,421,450)**	$ **4,620,766**
Capital expenditures	233,136	—	233,136
Transfers from exploration and evaluation assets (note 5)	3,712	—	3,712
Change in asset retirement obligations (note 9)	(5,058)	—	(5,058)
Divestitures	(1,884)	1,511	(373)
Property swaps	(4,734)	3,756	(978)
Foreign currency translation	(1,998)	1,130	(868)
Depletion	—	(164,435)	(164,435)
Balance, March 31, 2023	$ **12,265,390**	$ **(7,579,488)**	$ **4,685,902**

At March 31, 2023, there were no indicators of impairment or impairment reversal for oil and gas properties in any of the Company's CGUs.

At December 31, 2022, the Company identified indicators of impairment reversal for oil and gas properties in five of our six CGUs due to the increase in forecasted commodity prices in addition to changes in proved plus probable reserves. The recoverable amounts for three CGUs exceeded their carrying values which resulted in an impairment reversal of $245.2 million recorded at December 31, 2022. The recoverable amount for each CGU was based on its FVLCD which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2022. The after-tax discount rates applied to the cash flows were between 12% and 23%.

7. CREDIT FACILITIES

	March 31, 2023	December 31, 2022
Credit facilities - U.S. dollar denominated (1)	$ 27,595	$ 30,394
Credit facilities - Canadian dollar denominated	382,058	355,000
Credit facilities - principal (2)	409,653	385,394
Unamortized debt issuance costs	(2,180)	(2,363)
Credit facilities	$ 407,473	$ 383,031

(1) U.S. dollar denominated credit facilities balance was US$20.4 million as at March 31, 2023 (December 31, 2022 - US$22.5 million).

(2) The increase in the principal amount of the credit facilities outstanding from December 31, 2022 to March 31, 2023 is the result of net draws of $24.5 million, partially offset by a decrease in the reported amount of U.S. denominated debt of $0.3 million due to foreign exchange.

At March 31, 2023, Baytex had US$850 million of revolving credit facilities (the "Credit Facilities") that mature on April 1, 2026. The Credit Facilities are comprised of a US$50 million operating loan and a US$600 million syndicated revolving loan for Baytex and a US$10 million operating loan and a US$190 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc.

In connection with the Merger Transaction, we have entered into credit facility commitments with a syndicate of banks to provide aggregate debt commitments of US$1.75 billion comprised of a US$1.0 billion revolving credit facility (an increase from the committed amount of US$850 million in aggregate as of April 1, 2022), a two-year term loan of up to US$250 million and 364-day bridge loan facility in an aggregate principal amount of US$500 million (the "Bridge Loan"). The Bridge Loan was cancelled as of April 28, 2023. At closing of the merger with Ranger we expect to increase the capacity of the revolving credit facilities to US$1.1 billion. The amended agreement will contain an additional financial covenant of a maximum Total Debt to EBITDA ratio of 4.0:1.0.

The Credit Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. 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 6.0% for the three months ended March 31, 2023 (2.4% for three months ended March 31, 2022).

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at March 31, 2023.

Covenant Description	Position as at March 31, 2023	Covenant
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	0.3:1.0	3.5:1.0
Interest Coverage (3) (Minimum Ratio)	15.4:1.0	2.0:1.0

(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, 2023, the Company's Senior Secured Debt totaled $409.7 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, 2023 was $1.2 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, 2023 was $78.1 million.

At March 31, 2023, Baytex had $15.7 million of outstanding letters of credit under a $20 million uncommitted unsecured demand revolving letter of credit facility (December 31, 2022 - $15.7 million outstanding). Letters of credit under this facility are guaranteed by Export Development Canada and do not use capacity available under the Credit Facilities.

8. LONG-TERM NOTES

		March 31, 2023		December 31, 2022
8.75% notes due April 1, 2027 (1)	$	554,351	$	554,597
Total long-term notes - principal (2)		554,351		554,597
Unamortized debt issuance costs		(6,653)		(6,999)
Total long-term notes - net of unamortized debt issuance costs	$	547,698	$	547,598

(1) The U.S. dollar denominated principal outstanding of the 8.75% notes was US$409.8 million as at March 31, 2023 (December 31, 2022 - US$409.8 million).

(2) The decrease in the principal amount of long-term notes outstanding from December 31, 2022 to March 31, 2023 is the result of changes in the reported amount of U.S. denominated debt of $0.2 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 27, 2023, we closed the offering of the US$800 million aggregate principal amount of senior unsecured notes due 2030 ("8.5% Senior Notes") in a private offering. The 8.5% Senior Notes were priced at 98.709% of par and will bear interest at a rate of 8.5% per annum and mature on April 30, 2030. Proceeds from the 8.5% Senior Notes will initially be deposited into escrow and will be released at closing of the merger with Ranger.

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, 2023		December 31, 2022
Balance, beginning of period	$	588,923	$	743,683
Liabilities incurred		8,525		19,942
Liabilities settled		(4,126)		(18,351)
Liabilities acquired from property acquisitions		—		950
Liabilities divested		(590)		(3,464)
Accretion (note 15)		4,826		15,683
Government grants (1)		(1,271)		(4,009)
Change in estimate		1,377		6,124
Changes in discount and inflation rates (2)		(14,960)		(173,086)
Foreign currency translation		(10)		1,451
Balance, end of period	$	582,694	$	588,923
Less current portion of asset retirement obligations		12,884		12,813
Non-current portion of asset retirement obligations	$	569,810	$	576,110

(1) During the three months ended March 31, 2023, Baytex recognized $1.3 million of non-cash other income and a reduction in asset retirement obligations related to government grants provided by the Government of Alberta and the Government of Saskatchewan ($4.0 million for the year ended December 31, 2022).

(2) The discount and inflation rates at March 31, 2023 were 3.0% and 1.7%, respectively (December 31, 2022 - 3.3% 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. At March 31, 2023, 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.

During 2022, the TSX accepted Baytex's notice of intention to implement a Normal Course Issuer Bid ("NCIB"). Under the terms of the NCIB, the Company may purchase for cancellation up to 56.3 million common shares over the 12-month period commencing May 9, 2022. The number of shares authorized for repurchase represents 10% of the Company's public float as at April 29, 2022. Purchases are made on the open market at prices prevailing at the time of the transaction.

	Number of Common Shares (000s)		Amount
Balance, December 31, 2021	**564,213**	**$**	**5,736,593**
Vesting of share awards	5,035		8,501
Common shares repurchased and cancelled	(24,318)		(245,430)
Balance, December 31, 2022	**544,930**	**$**	**5,499,664**
Vesting of share awards	623		3,421
Balance, March 31, 2023	**545,553**	**$**	**5,503,085**

11. SHARE-BASED COMPENSATION PLAN

For the three months ended March 31, 2023 the Company recorded total share-based compensation expense of $9.8 million ($3.9 million for the three months ended March 31, 2022) which is comprised of the expense related to cash-settled awards and the associated equity total return swaps ($2.2 million for the three months ended March 31, 2022).

The Company's closing share price on March 31, 2023 was $5.07 (March 31, 2022 - $5.45).

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 trade and other payables.

The weighted average fair value of share awards granted during the three months ended March 31, 2023 was $5.49 per restricted and performance award ($5.68 for the three months ended March 31, 2022).

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, 2021	**2,093**	**7,381**	**9,474**
Granted	68	1,391	1,459
Vested	(1,377)	(3,630)	(5,007)
Forfeited	(22)	(346)	(368)
Balance, December 31, 2022	**762**	**4,796**	**5,558**
Granted	—	2,159	2,159
Vested	(684)	(3,767)	(4,451)
Forfeited	(10)	(55)	(65)
Balance, March 31, 2023	**68**	**3,133**	**3,201**

Incentive Award Plan

Baytex has an Incentive Award Plan whereby the holder of each incentive award is entitled to receive a cash payment equal to the value of one Baytex common share 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 trade and other payables.

During the three months ended March 31, 2023, Baytex granted 1.5 million awards under the Incentive Award Plan at a fair value of $5.49 per award (1.3 million awards at $5.68 per award for the three months ended March 31, 2022). At March 31, 2023 there were 3.9 million awards outstanding under the Incentive Award Plan (5.1 million awards outstanding at December 31, 2022).

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 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 trade and other payables.

During the three months ended March 31, 2023, Baytex granted 0.2 million awards under the DSU Plan at a fair value of $5.49 per award (0.2 million awards at $5.68 per award for the three months ended March 31, 2022). At March 31, 2023, there were 1.2 million awards outstanding under the DSU Plan.

Equity Total Return Swaps

The Company uses equity total return swaps on the equivalent number of Baytex common shares in order to fix the aggregate cost of the Company's cash-settled plans including the Incentive Award Plan, the DSU Plan and the Share Award Incentive Plan, at the fair value determined on the grant date.

At March 31, 2023, an asset of $1.6 million associated with the equity total return swap was included in trade and other receivables (December 31, 2022 - $21.2 million).

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					
	2023			2022		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	Net income	Weighted average common shares (000s)	Net income per share
Net income - basic	**$ 51,441**	**545,062**	**$ 0.09**	$ 56,858	565,518	$ 0.10
Dilutive effect of share awards	**—**	**3,016**	**—**	—	4,187	—
Net income - diluted	**$ 51,441**	**548,078**	**$ 0.09**	$ 56,858	569,705	$ 0.10

For the three months ended March 31, 2023 and March 31, 2022 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					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 146,456**	**$ 142,011**	**$ 288,467**	$ 180,156	$ 180,820	$ 360,976
Heavy oil	**217,085**	**—**	**217,085**	244,439	—	244,439
NGL	**6,059**	**15,774**	**21,833**	7,483	22,007	29,490
Natural gas sales	**16,022**	**11,929**	**27,951**	21,626	17,294	38,920
Total petroleum and natural gas sales	**$ 385,622**	**$ 169,714**	**$ 555,336**	$ 453,704	$ 220,121	$ 673,825

Included in accounts receivable at March 31, 2023 is $189.0 million of accrued production revenue related to delivered volumes (December 31, 2022 - $183.0 million).

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Three Months Ended March 31	
	2023	2022
Net income (loss) before income taxes	**$ 68,084**	$ (9,564)
Expected income taxes at the statutory rate of 24.80% (2022 – 24.80%)	**16,885**	(2,402)
Change in income taxes resulting from:		
Effect of foreign exchange	**(30)**	(1,848)
Effect of rate adjustments for foreign jurisdictions	**(2,176)**	(3,572)
Effect of change in deferred tax benefit not recognized [1]	**(30)**	9,292
Effect of internal debt restructuring	**—**	(67,301)
Adjustments, assessments and other	**1,994**	(591)
Income tax expense (recovery)	**$ 16,643**	$ (66,422)

(1) A deferred income tax asset of $14.3 million remains unrecognized due to uncertainty surrounding future capital gains (December 31, 2022- $14.4 million). The unrecognized deferred income tax asset relates to realized and unrealized foreign exchange losses arising from the repayment of previously issued U.S. dollar denominated long-term notes and from the translation of U.S. dollar denominated long-term notes currently outstanding.

As disclosed in the 2022 annual financial statements, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the "CRA") that denied $591.0 million of non-capital loss deductions that relate to the calculation of income taxes for the years 2011 through 2015. In September 2016, Baytex filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to the Company's file in July 2018. Baytex remains confident that the original tax filings are correct and intends to defend those tax filings through the appeals process.

15. FINANCING AND INTEREST

	Three Months Ended March 31	
	2023	2022
Interest on Credit Facilities	**$ 6,216**	$ 3,039
Interest on long-term notes	**12,094**	17,344
Interest on lease obligations	**65**	44
Cash interest	**$ 18,375**	$ 20,427
Amortization of debt issue costs	**524**	695
Accretion on asset retirement obligations (note 9)	**4,826**	3,122
Financing and interest	**$ 23,725**	$ 24,244

16. FOREIGN EXCHANGE

	Three Months Ended March 31	
	2023	2022
Unrealized foreign exchange gain - intercompany notes [1]	**$ —**	$ (2,674)
Unrealized foreign exchange gain - long-term notes & Credit Facilities	**(213)**	(11,874)
Realized foreign exchange loss	**150**	203
Foreign exchange gain	**$ (63)**	$ (14,345)

(1) Baytex had a series of intercompany notes totaling US$601.0 million outstanding at December 31, 2021 that were issued from a Canadian functional currency subsidiary to a U.S. functional currency subsidiary. These notes were eliminated upon consolidation within the Statement of Financial Position and were revalued at the relevant foreign exchange rate at each period end. Foreign exchange gains or losses incurred within the Canadian functional currency subsidiary were recognized in unrealized foreign exchange gain or loss whereas those within the U.S. functional currency subsidiary were recognized in other comprehensive income. In January 2022 the intercompany notes were transferred from the Canadian functional currency subsidiary to another U.S. functional currency subsidiary. As a result, foreign exchange gains and losses incurred on these notes after the transfer are recognized in other comprehensive income.

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, Credit Facilities, and long-term notes. The fair value of trade and other receivables and trade and other 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, 2023		December 31, 2022		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
Fair value through profit and loss					
Financial derivatives	**$ 19,315**	**$ 19,315**	$ 10,105	$ 10,105	Level 2
Total	**$ 19,315**	**$ 19,315**	$ 10,105	$ 10,105	
Amortized cost					
Cash	**$ 6,445**	**$ 6,445**	$ 5,464	$ 5,464	—
Trade and other receivables	**233,411**	**233,411**	228,485	228,485	—
Total	**$ 239,856**	**$ 239,856**	$ 233,949	$ 233,949	
Financial Liabilities					
Amortized cost					
Trade and other payables	**$ (271,022)**	**$ (271,022)**	$ (281,404)	$ (281,404)	—
Credit Facilities	**(407,473)**	**(409,653)**	(383,031)	(385,394)	—
Long-term notes	**(547,698)**	**(569,179)**	(547,598)	(563,292)	Level 1
Total	**$ (1,226,193)**	**$ (1,249,854)**	$ (1,212,033)	$ (1,230,090)	

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 2023 and 2022.

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, 2023	December 31, 2022	**March 31, 2023**	December 31, 2022
U.S. dollar denominated	**US$16,109**	US$6,980	**US$434,066**	US$430,171

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of May 4, 2023:

	Remaining Period	Volume	Price/Unit [1]	Index
Oil				
Basis differential [2]	May 2023 to Dec 2023	1,500 bbl/d	Baytex pays: MSW Baytex receives: WTI less US$2.50/bbl	MSW
Basis differential [2]	May 2023 to Dec 2023	5,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.10/bbl	WCS
Collar [3][4]	May 2023 to Dec 2023	14,500 bbl/d	US$60.00/US$100.00	WTI
Put option [4]	May 2023 to Dec 2023	5,000 bbl/d	US$60.00	WTI

(1) Based on the weighted average price per unit for the period.
(2) Contracts that fix the basis differential between certain oil reference prices.
(3) As of March 31, 2023, Baytex had 3-way option contracts with a total volume of 9,500 bbl/d with an average sold put price of US$61.58/bbl, an average bought put price of US$78.37/bbl and an average sold call price of US$96.12/bbl along with a 5,000 bbl/d collar contract with a bought put price of US$60.00/bbl and sold call price US$94.00/bbl. On May 3, 2023 the Company restructured these hedges into a collar with a bought put price of US$60.00/bbl and sold call price US$100.00/bbl and received US$11.3 million.
(4) Contract entered subsequent to March 31, 2023.

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

	Three Months Ended March 31	
	2023	2022
Realized financial derivatives (gain) loss	**$ (5,415)**	$ 84,366
Unrealized financial derivatives (gain) loss	**(9,210)**	156,261
Financial derivatives (gain) loss	**$ (14,625)**	$ 240,627

18. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain financial flexibility and sufficient sources of liquidity to execute its capital programs, while meeting short and long-term commitments. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At March 31, 2023, the Company's capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables, 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.

Total Debt and Net Debt

The Company uses total debt and net debt to monitor its current financial position and to evaluate existing sources of liquidity. The Company defines total debt to be the sum of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs. To arrive at net debt, the Company also adjusts for trade and other payables, cash, and trade and other receivables. Baytex also uses total debt and net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Baytex uses a net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis to monitor the Company's existing capital structure and future liquidity requirements.

The following table reconciles Total Debt and Net Debt to amounts disclosed in the primary financial statements.

	March 31, 2023	December 31, 2022
Credit Facilities	$ 407,473	$ 383,031
Unamortized debt issuance costs - Credit Facilities (note 7)	2,180	2,363
Long-term notes	547,698	547,598
Unamortized debt issuance costs - Long-term notes (note 8)	6,653	6,999
Total Debt	$ 964,004	$ 939,991
Trade and other payables	271,022	281,404
Cash	(6,445)	(5,464)
Trade and other receivables	(233,411)	(228,485)
Net Debt	$ 995,170	$ 987,446
Net Debt to Adjusted Funds Flow	0.9	0.8

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 and asset retirements obligations settled during the applicable period.

Adjusted Funds Flow is reconciled to amounts disclosed in the primary financial statements in the following table.

	Three Months Ended March 31	
	2023	2022
Cash flows from operating activities	$ 184,938	$ 198,974
Change in non-cash working capital	39,054	77,340
Asset retirement obligations settled	4,126	3,293
Transaction costs	8,871	—
Adjusted Funds Flow	$ 236,989	$ 279,607

CORPORATE INFORMATION

BOARD OF DIRECTORS

Mark R. Bly
Chairman of the Board

Eric T. Greager
Director

Trudy M. Curran [2,4]
Director

Don G. Hrap [1,3]
Director

Jennifer A. Maki [1,2]
Director

Gregory K. Melchin [1,4]
Director

Angela S. Lekatsas
Director

David L. Pearce [2,3]
Director

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

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

HEAD OFFICE

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

Toll-free 1.800.524.5521
T 587.952.3000
F 587.952.3001

WWW.BAYTEXENERGY.COM

OFFICERS

Eric T. Greager
President and Chief Executive Officer

Chad L. Kalmakoff
Chief Financial Officer

Chad E. Lundberg
Chief Operating and Sustainability Officer

Kendall D. Arthur
Vice President, Heavy Oil

Brian G. Ector
Vice President, Capital Markets

Nicole M. Frechette
Vice President, Light Oil

Scott Lovett
Vice President, Corporate Development

James R. Maclean
Vice President, General Counsel and Corporate Secretary

AUDITORS

KPMG LLP

RESERVES ENGINEERS

McDaniel & Associates Consultants Ltd.

TRANSFER AGENT

Odyssey Trust Company

EXCHANGE LISTINGS

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

Design: ARTHUR / HUNTER
Printing: Merrill Corporation

BAYTEX