Q3 REPORT
2023

BAYTEX ANNOUNCES THIRD QUARTER 2023 RESULTS

CALGARY, ALBERTA (November 2, 2023) - Baytex Energy Corp. ("Baytex") (TSX:BTE) (NYSE:BTE) reports its operating and financial results for the three and nine months ended September 30, 2023 (all amounts are in Canadian dollars unless otherwise noted).

“Our third quarter results represent the first full quarter of combined operations following the Ranger acquisition and demonstrate the strength of our diversified North American oil-weighted portfolio. The integration has progressed extremely well and we have delivered strong results from Western Canada and the Eagle Ford in Texas. We are building momentum with current production exceeding 155,000 boe/d (84% oil and NGLs). Currently, we expect to generate free cash flow of approximately $400 million in Q4/2023 and $650 million for this year. As a result of this strong free cash flow, we have increased the pace of our share buyback program during the fourth quarter. We are also excited to announce two new land extensions at Peavine and Cold Lake as we continue to leverage our heavy oil expertise and recent exploration successes," commented Eric T. Greager, President and Chief Executive Officer.

Highlights

- Generated production of 150,600 boe/d (85% oil and NGLs) in Q3/2023.
- Reported cash flows from operating activities of $444 million ($0.52 per basic share) in Q3/2023.
- Delivered adjusted funds flow[(1)] of $582 million ($0.68 per basic share) in Q3/2023.
- Generated free cash flow[(2)] of $158 million ($0.19 per basic share) in Q3/2023.
- Exploration and development expenditures totaled $409 million in Q3/2023, consistent with our full-year plan.
- Repurchased 16.8 million common shares in Q3/2023, representing 2.0% of our shares outstanding, at an average price of $5.29 per share.
- Paid a quarterly cash dividend of $0.0225 per share ($0.09 per share annualized) on October 2, 2023.
- Brought 13 operated Eagle Ford wells onstream in Q3/2023, of which seven wells from three pads generated average 30-day initial production rates of approximately 2,000 boe/d (65% oil and NGLs) per well.
- Executed a two-rig drilling program at Peavine and brought 14 Clearwater wells onstream. Production at Peavine averaged 13,821 bbl/d in Q3/2023, up 69% from Q3/2022. Production during September averaged 16,400 bbl/d.
- Continued commercialization program in our Pembina Duvernay with six-well program delivering strong results.
- Expanded our heavy oil development fairway through two land extensions, including a 10-section agreement with the Peavine Métis settlement adjacent to our existing 80 section land position and a farm-in on 17.75 sections of land prospective for Mannville development near Cold Lake in northeast Alberta.

Quarterly Dividend

The Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on January 2, 2024 for shareholders of record on December 15, 2023.

(1) Capital management measure. Refer to the Specified Financial Measures 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.

2023 Outlook

We continue to execute our 2023 plan and anticipate full-year 2023 production of 121,500 to 122,000 boe/d (previous guidance range of 120,500 to 122,500 boe/d). Production during the fourth quarter is expected to average 158,000 to 160,000 boe/d, 84% weighted to oil and NGLs (47% light oil, 24% heavy oil and 13% NGLs) and 16% natural gas. We anticipate full-year 2023 exploration and development expenditures of approximately $1,035 million, consistent with our previous guidance range of $1,005 to $1,045 million. Based on the forward strip for the balance of 2023[1], we expect to generate free cash flow[2] of approximately $400 million ($0.48 per basic share) in Q4/2023 and $650 million ($0.92 per basic share) for the full-year 2023.

The following table summarizes our 2023 guidance for production and exploration and development expenditures.

	H1/2023 Actual	Q3/2023 Actual	Q4/2023 Estimate	2023 Guidance
Production (boe/d)	88,269 [3]	150,600 [4]	158,000 - 160,000	121,500 - 122,000
Exploration and development expenditures ($ millions)	$404	$409	~$222	~$1,035

The following table summarizes our 2023 guidance for expenses, leasing expenditures and asset retirement obligations.

Guidance for unit operating expenses moves to the high end of our previous range to reflect incremental base optimization and workover activity in the Eagle Ford. Guidance for interest expense is higher due largely to the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt.

	2023 Guidance[5]	2023 Revised Guidance
Expenses:		
Average royalty rate [2]	21.0 - 22.0%	no change
Operating [6]	$12.25 - $12.75/boe	~ $12.75/boe
Transportation [6]	$2.00 - $2.10/boe	~ $2.10/boe
General and administrative [6]	$80 million ($1.80/boe)	no change
Interest [6]	$150 million ($3.38/boe)	$156 million ($3.50/boe)
Leasing expenditures	$13 million	no change
Asset retirement obligations	$25 million	no change

Our 2024 capital budget is expected to be released in early December following approval by our Board of Directors.

Shareholder Returns

In conjunction with closing the Ranger Oil Corporation ("Ranger") transaction, we increased direct shareholder returns to 50% of free cash flow[2] which has allowed us to increase the value of our share buyback program and introduce a dividend. The remainder of our free cash flow continues to be allocated to the balance sheet.

Our normal course issuer bid allows for the purchase of up to 68.4 million common shares during the 12-month period ending June 28, 2024. During the third quarter, we repurchased 16.8 million common shares for $89 million, representing 2.0% of our shares outstanding, at an average price of $5.29 per share. Through October 31, 2023, we repurchased 28.1 million common shares for $155.0 million, representing 3.3% of our shares outstanding, at an average price of $5.51 per share. In addition, we paid an initial quarterly cash dividend of $0.0225 per share ($0.09 per share annualized) on October 2, 2023.

As of September 30, 2023, our total debt[7] was $2.7 billion, representing a total debt to EBITDA[7] ratio (Q3/2023 annualized) of 1.1x. Our total debt at quarter-end increased relative to Q2/2023 due to the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt, and working capital adjustments. Based on current commodity prices and forecast free cash flow for the fourth quarter, we expect to exit 2023 with total debt of approximately $2.5 billion.

(1) Q4/2023 commodity prices: WTI - US$84/bbl, WCS differential to WTI - US$21/bbl, NYMEX Gas - US$3.00/MMbtu; Exchange Rate (CAD/USD) - 1.38.
(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) H1/2023 actual production is comprised of 33,510 bbl/d of light crude oil and medium crude oil (including condensate), 33,502 bbl/d of heavy crude oil, 7,920 bbl/d of natural gas liquids and 80,017 mcf/d of conventional natural gas.
(4) Q3/2023 actual production is comprised of 75,763 bbl/d of light crude oil and medium crude oil (including condensate), 35,204 bbl/d of heavy crude oil, 18,004 bbl/d of natural gas liquids and 129,780 mcf/d of conventional natural gas.
(5) As announced on July 27, 2023. Includes Ranger from the closing date of the transaction (June 20, 2023).
(6) Calculated as operating, transportation, general and administrative or cash interest expense divided by barrels of oil equivalent production volume for the applicable period.
(7) Calculated in accordance with the amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.

	Three Months Ended			Nine Months Ended	
	September 30, 2023	June 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 1,163,010**	$ 598,760	$ 712,065	**$ 2,317,106**	$ 2,240,059
Adjusted funds flow (1)	**581,623**	273,590	284,288	**1,092,202**	909,599
Per share – basic	**0.68**	0.47	0.51	**1.65**	1.62
Per share – diluted	**0.68**	0.47	0.51	**1.64**	1.60
Free cash flow (2)	**158,440**	96,313	111,568	**252,835**	478,202
Per share – basic	**0.19**	0.17	0.20	**0.38**	0.85
Per share – diluted	**0.18**	0.16	0.20	**0.38**	0.84
Cash flows from operating activities	**444,033**	192,308	310,423	**821,279**	869,431
Per share – basic	**0.52**	0.33	0.56	**1.24**	1.55
Per share – diluted	**0.52**	0.33	0.56	**1.23**	1.53
Net income	**127,430**	213,603	264,968	**392,474**	502,798
Per share – basic	**0.15**	0.37	0.48	**0.59**	0.89
Per share – diluted	**0.15**	0.36	0.47	**0.59**	0.89
Dividends declared	**19,138**	—	—	**19,138**	—
Per share	**0.0225**	—	—	**0.0225**	—
Capital Expenditures					
Exploration and development expenditures	**$ 409,191**	$ 170,704	$ 167,453	**$ 813,521**	$ 417,908
Acquisitions and divestitures	**4,051**	(112)	(25,460)	**4,210**	(25,234)
Net oil and natural gas capital expenditures	**$ 413,242**	$ 170,592	$ 141,993	**$ 817,731**	$ 392,674
Net Debt					
Credit facilities	**$ 1,046,756**	$ 986,903	$ 450,051	**$ 1,046,756**	$ 450,051
Long-term notes	**1,637,640**	1,601,468	648,207	**1,637,640**	648,207
Total debt (3)	**2,684,396**	2,588,371	1,098,258	**2,684,396**	1,098,258
Working capital	**139,952**	226,473	15,301	**139,952**	15,301
Net debt (1)	**$ 2,824,348**	$ 2,814,844	$ 1,113,559	**$ 2,824,348**	$ 1,113,559
Shares Outstanding - basic (thousands)					
Weighted average	**855,300**	583,365	553,409	**662,379**	561,931
End of period	**845,360**	862,192	547,615	**845,360**	547,615
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 82.26**	$ 73.78	$ 91.56	**$ 77.39**	$ 98.09
MEH oil (US$/bbl)	**84.10**	75.01	96.15	**78.84**	101.76
MEH oil differential to WTI (US$/bbl)	**1.84**	1.23	4.59	**1.45**	3.67
Edmonton par ($/bbl)	**107.93**	95.13	116.79	**100.70**	123.41
Edmonton par differential to WTI (US$/bbl)	**(1.78)**	(2.95)	(2.13)	**(2.54)**	(1.89)
WCS heavy oil ($/bbl)	**93.02**	78.85	93.62	**80.47**	105.65
WCS differential to WTI (US$/bbl)	**(12.89)**	(15.07)	(19.87)	**(17.57)**	(15.74)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.55**	$ 2.10	$ 8.20	**$ 2.69**	$ 6.77
AECO ($/mcf)	**2.39**	2.35	5.81	**3.03**	5.56
CAD/USD average exchange rate	**1.3410**	1.3431	1.3059	**1.3453**	1.2829

	Three Months Ended			Nine Months Ended	
	September 30, 2023	June 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**75,763**	35,322	33,247	**47,750**	33,437
Heavy oil (bbl/d)	**35,204**	32,821	29,244	**34,076**	27,703
NGL (bbl/d)	**18,004**	8,620	7,536	**11,318**	7,547
Total liquids (bbl/d)	**128,971**	76,763	70,027	**93,144**	68,686
Natural gas (mcf/d)	**129,780**	77,989	79,003	**96,787**	82,232
Oil equivalent (boe/d @ 6:1) [4]	**150,600**	89,761	83,194	**109,275**	82,392
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense [2]	**$ 1,113,180**	$ 545,765	$ 671,120	**$ 2,154,600**	$ 2,100,779
Royalties	**(240,049)**	(107,920)	(146,994)	**(441,222)**	(441,273)
Operating expense	**(174,119)**	(119,438)	(110,139)	**(405,965)**	(318,331)
Transportation expense	**(27,983)**	(14,574)	(12,771)	**(59,562)**	(33,744)
Operating netback [2]	**$ 671,029**	**$ 303,833**	**$ 401,216**	**$ 1,247,851**	**$ 1,307,431**
General and administrative	**(20,536)**	(15,240)	(12,003)	**(47,510)**	(35,325)
Cash financing and interest	**(56,495)**	(28,255)	(19,774)	**(103,125)**	(60,675)
Realized financial derivatives gain (loss)	**2,055**	16,365	(76,408)	**23,835**	(284,816)
Other [5]	**(14,430)**	(3,113)	(8,743)	**(28,849)**	(17,016)
Adjusted funds flow [1]	**$ 581,623**	**$ 273,590**	**$ 284,288**	**$ 1,092,202**	**$ 909,599**
Netback (per boe) [6]					
Total sales, net of blending and other expense [2]	**$ 80.34**	$ 66.82	$ 87.68	**$ 72.22**	$ 93.40
Royalties	**(17.33)**	(13.21)	(19.21)	**(14.79)**	(19.62)
Operating expense	**(12.57)**	(14.62)	(14.39)	**(13.61)**	(14.15)
Transportation expense	**(2.02)**	(1.78)	(1.67)	**(2.00)**	(1.50)
Operating netback [2]	**$ 48.42**	**$ 37.21**	**$ 52.41**	**$ 41.82**	**$ 58.13**
General and administrative	**(1.48)**	(1.87)	(1.57)	**(1.59)**	(1.57)
Cash financing and interest	**(4.08)**	(3.46)	(2.58)	**(3.46)**	(2.70)
Realized financial derivatives gain (loss)	**0.15**	2.00	(9.98)	**0.80**	(12.66)
Other [4]	**(1.03)**	(0.39)	(1.14)	**(0.96)**	(0.76)
Adjusted funds flow [1]	**$ 41.98**	**$ 33.49**	**$ 37.14**	**$ 36.61**	**$ 40.44**

Notes:

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Calculated in accordance with the amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.
(4) 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.
(5) 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 Q3/2023 MD&A for further information on these amounts.
(6) 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.

Q3/2023 Results

Our third quarter results represent the first full quarter of operations following the acquisition of Ranger and demonstrate the strength of our diversified North American oil weighted portfolio. We continue to integrate the Ranger assets and execute our development program with strong results in Western Canada and the Eagle Ford.

Production during the third quarter averaged 150,600 boe/d (85% oil and NGLs). We delivered adjusted funds flow(1) of $582 million ($0.68 per basic share), cash flows from operating activities of $444 million ($0.52 per basic share) and net income of $127 million ($0.15 per basic share) in Q3/2023. Exploration and development expenditures totaled $409 million in Q3/2023 and we brought 105 (87.8 net) wells onstream. During the third quarter, we generated free cash flow(2) of $158 million ($0.19 per basic share).

Operating Results

Light Oil - United States

Our light oil assets in the United States are located in the liquids-rich Eagle Ford formation, in the Texas Gulf Coast Basin. The Ranger acquisition materially increased the scale of our Eagle Ford operations, adding 162,000 operated net acres in the crude oil window on-trend with our non-operated position in the Karnes Trough. The transaction increased our exposure to premium U.S. Gulf Coast pricing and includes substantial infrastructure in place with low operating and transportation costs.

Production in the Eagle Ford averaged 87,311 boe/d (85% oil and NGLs) during Q3/2023. During the third quarter, we brought 36 (21.3 net) wells onstream, including 13 (12.9 net) operated wells. The third quarter program reflects strong results across the black oil and condensate thermal maturity windows of the Lower Eagle Ford. The 13 operated wells generated an average 30-day initial production rate of 1,495 boe/d (78% oil and NGLs) per well (ranging from 769 boe/d to 2,355 boe/d). Seven wells from three pads (Bloodstone, Bubinga and Hickory) generated an average 30-day initial production rate of 2,000 boe/d (65% oil and NGLs) per well.

Given the timing of on-streaming wells, production in the Eagle Ford increased to over 92,000 boe/d in September. In addition to delivering strong results, we remain focused on base optimization and continued strong drilling and completion performance.

Light Oil - Canada

Our light oil production and development in Canada occurs from the Viking formation in west-central Saskatchewan and east-central Alberta, and the Duvernay formation in the Pembina area of central Alberta. The Viking is a shallow and highly repeatable light oil resource play with some of the highest operating netbacks in North America. Our Pembina Duvernay light oil assets are in the demonstration stage of commerciality and offer high operating netbacks, with strong economics and the potential for significant organic growth.

Our light oil production in Canada averaged 21,088 boe/d (87% oil and NGLs) during Q3/2023. In the Viking, we brought 38 (35.5 net) wells onstream in Q3/2023. In the Pembina Duvernay, commercialization continued with our six-well program (two-three well pads) delivering strong results with production increasing to over 7,500 boe/d in September (up from 2,000 boe/d in H1/2023). The six wells generated average production rates of approximately 950 boe/d (89% oil and NGLs) in September (ranging from 790 boe/d to 1,080 boe/d) and continue to track to type curve expectations. The 2023 program has advanced our understanding of the reservoir as we continue to progress this light oil resource play.

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 the use of innovative multi-lateral horizontal drilling with strong capital efficiencies. The core of our Clearwater play is located on the Peavine Métis settlement.

Our heavy oil assets produced a combined 37,507 boe/d (94% oil and NGLs) during Q3/2023. Following a relatively quiet second quarter due to spring breakup, our heavy oil development program ramped up during the third quarter with 25 net heavy oil wells onstream, 14 at Peavine, 8 at Lloydminster and 3 at Peace River. At Peavine, the 14 wells generated an average 30-day initial production rate of 725 bbl/d per well (ranging from 330 bbl/d to 1,073 bbl/d). Production at Peavine averaged 13,821 bbl/d in Q3/2023, up 69% from Q3/2022, and 16,400 bbl/d during the month of September.

(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.

We are following up on our recent heavy oil exploration success at Morinville, Alberta and Cold Lake, Alberta. At Morinville, where we have aggregated approximately 30 sections of prospective land, we drilled two Clearwater equivalent test wells during the third quarter with the wells placed on production in Q4/2023. At Cold Lake, where we hold 20 sections of land prospective for the Waseca formation, we expect to drill 3 follow-up wells in Q4/2023, including a Lower Waseca test.

Building on our heavy oil expertise, we have expanded our heavy oil development fairway through two land extensions, including a 10-section agreement with the Peavine Métis settlement adjacent to our existing 80 section land position and a farm-in on 17.75 sections of land prospective for Mannville development near Cold Lake in northeast Alberta.

Financial Liquidity

We are well capitalized and have significant liquidity on our credit facilities. We have a US$1.1 billion revolving credit facility with a maturity date of April 1, 2026. During the third quarter, we repaid our US$150 million term loan.

As at September 30, 2023, our total debt[(1)], which includes our two series of long-term notes, is $2.7 billion and we maintain strong liquidity with approximately 30% undrawn capacity on our revolving credit facility. Our total debt at quarter-end increased relative to Q2/2023 due to the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt, and working capital adjustments.

Risk Management

We employ a disciplined commodity hedging program to help mitigate the volatility in revenue due to changes in commodity prices.

For Q4/2023, we have entered into hedges on approximately 40% of our net crude oil exposure utilizing a combination of two-way collars 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.

For the first half of 2024, we have entered into hedges on approximately 40% of our net crude oil exposure utilizing two-way collars with a floor price of US$60/bbl and a ceiling price of US$100/bbl. For the second half of 2024, we have entered into hedges on approximately 25% of our net crude oil exposure utilizing two-way collars with a floor price of US$60/bbl and a ceiling price of US$98/bbl.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q3/2023 financial statements.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and nine months ended September 30, 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.sedarplus.com and EDGAR at www.sec.gov/edgar.shtml.

(1) Calculated in accordance with the amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.

Advisory Regarding Forward-Looking Statements

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

Specifically, this press release contains forward-looking statements relating to but not limited to: we expect to generate over $400 million of free cash flow in Q4 of 2023, and approximately $650 million of free cash flow for the full-year 2023; our guidance for 2023 exploration and development expenditures, production (including production mix by product type), royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; our expected total debt at year-end 2023; our plans for follow up wells to be drilled at Cold Lake, Alberta and Morinville, Alberta; and our hedging plans.

These forward-looking statements are based on certain key assumptions regarding, among other things: 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; that our core assets have more than 10 years development inventory at the current pace of development; 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, including operating and transportation costs; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our hedging program; 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: risks relating to any unforeseen liabilities of Baytex; that Baytex fails to meet its guidance; 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, including transportation costs; 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.

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" 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			Nine Months Ended	
($ thousands)	**September 30, 2023**	June 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022
Petroleum and natural gas sales	**$ 1,163,010**	$ 598,760	$ 712,065	**$ 2,317,106**	$ 2,240,059
Blending and other expense	**(49,830)**	(52,995)	(40,945)	**(162,506)**	(139,280)
Total sales, net of blending and other expense	**1,113,180**	545,765	671,120	**2,154,600**	2,100,779
Royalties	**(240,049)**	(107,920)	(146,994)	**(441,222)**	(441,273)
Operating expense	**(174,119)**	(119,438)	(110,139)	**(405,965)**	(318,331)
Transportation expense	**(27,983)**	(14,574)	(12,771)	**(59,562)**	(33,744)
Operating netback	**$ 671,029**	$ 303,833	$ 401,216	**$ 1,247,851**	$ 1,307,431

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			Nine Months Ended	
($ thousands)	**September 30, 2023**	June 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022
Cash flows from operating activities	**$ 444,033**	$ 192,308	$ 310,423	**$ 821,279**	$ 869,431
Change in non-cash working capital	**126,075**	40,795	(30,734)	**205,924**	29,560
Additions to exploration and evaluation assets	**(40)**	(741)	—	**(1,271)**	(5,897)
Additions to oil and gas properties	**(409,151)**	(169,963)	(167,453)	**(812,250)**	(412,011)
Payments on lease obligations	**(4,740)**	(1,181)	(668)	**(7,076)**	(2,881)
Transaction costs	**2,263**	32,832	—	**43,966**	—
Cash premiums on derivatives	**—**	2,263	—	**2,263**	—
Free cash flow	**$ 158,440**	$ 96,313	$ 111,568	**$ 252,835**	$ 478,202

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

Net debt

We use net debt to monitor our current financial position and to evaluate existing sources of liquidity. We define net debt to be the sum of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs adjusted for trade and other payables, cash, and trade receivables and prepaids. We believe that this measure assists 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 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)	**September 30, 2023**	June 30, 2023	December 31, 2022
Credit facilities	**$ 1,028,867**	$ 964,332	$ 383,031
Unamortized debt issuance costs - Credit facilities (1)	**17,889**	22,571	2,363
Long-term notes	**1,600,397**	1,563,897	547,598
Unamortized debt issuance costs - Long-term notes (1)	**37,243**	37,571	6,999
Trade and other payables	**685,392**	616,608	281,404
Dividends payable	**19,138**	—	—
Cash	**(23,899)**	(19,637)	(5,464)
Trade receivables and prepaids	**(540,679)**	(370,498)	(228,485)
Net debt	**$ 2,824,348**	$ 2,814,844	$ 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 and nine months ended September 30, 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			Nine Months Ended	
($ thousands)	**September 30, 2023**	June 30, 2023	September 30, 2022	**September 30, 2023**	September 30, 2022
Cash flow from operating activities	**$ 444,033**	$ 192,308	$ 310,423	**$ 821,279**	$ 869,431
Change in non-cash working capital	**126,075**	40,795	(30,734)	**205,924**	29,560
Asset retirement obligations settled	**9,252**	5,392	4,599	**18,770**	10,608
Transaction costs	**2,263**	32,832	—	**43,966**	—
Cash premiums on derivatives	**—**	2,263	—	**2,263**	—
Adjusted funds flow	**$ 581,623**	$ 273,590	$ 284,288	**$ 1,092,202**	$ 909,599

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 oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and nine months ended September 30, 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 September 30, 2023					**Three Months Ended September 30, 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	9,766	8	45	12,075	11,831	10,282	13	41	12,026	12,340
Lloydminster	11,617	20	—	1,300	11,854	10,770	4	—	1,575	11,037
Peavine	13,821	—	—	—	13,821	8,191	—	—	—	8,191
Canada - Light										
Viking	—	14,074	253	12,015	16,330	—	13,908	191	11,516	16,019
Duvernay	—	2,962	1,130	3,996	4,758	—	1,894	959	3,305	3,405
Remaining Properties	—	577	674	20,672	4,695	—	690	682	20,638	4,811
United States										
Eagle Ford	—	58,122	15,902	79,722	87,311	—	16,738	5,663	29,943	27,391
Total	35,204	75,763	18,004	129,780	150,600	29,244	33,247	7,536	79,003	83,194

	Nine Months Ended September 30, 2023					**Nine Months Ended September 30, 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	10,113	9	49	11,488	12,086	10,691	9	33	11,877	12,713
Lloydminster	11,554	18	—	1,249	11,780	10,773	9	—	1,696	11,065
Peavine	12,409	—	—	—	12,409	6,240	—	—	—	6,240
Canada - Light										
Viking	—	13,991	210	11,915	16,186	—	14,562	188	12,203	16,783
Duvernay	—	1,573	881	2,860	2,931	—	1,233	790	2,555	2,449
Remaining Properties	—	631	664	19,565	4,556	—	769	864	22,972	5,461
United States										
Eagle Ford	—	31,528	9,514	49,710	49,327	—	16,855	5,671	30,929	27,681
Total	34,076	47,750	11,318	96,787	109,275	27,703	33,437	7,546	82,232	82,392

Baytex Energy Corp.

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

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

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BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three and nine months ended September 30, 2023 and 2022
Dated November 2, 2023

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and nine months ended September 30, 2023. This information is provided as of November 2, 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 and nine months ended September 30, 2023 ("Q3/2023" and "YTD 2023") have been compared with the results for the three and nine months ended September 30, 2022 ("Q3/2022" and "YTD 2022"). This MD&A should be read in conjunction with the Company's unaudited condensed consolidated interim financial statements ("consolidated financial statements") as at September 30, 2023, and for the three and nine months ended September 30, 2023 and 2022, 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.sedarplus.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" and "net debt" which are capital management measures. Refer to our advisory on forward-looking information and statements and a summary of our specified financial measures at the end of the MD&A.

BAYTEX ENERGY CORP.

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

On June 20, 2023, Baytex and Ranger Oil Corporation ("Ranger") completed the merger of the two companies (the "Merger") whereby Baytex acquired all of the issued and outstanding common shares of Ranger. The Merger increases our Eagle Ford scale and provides an operating platform to effectively allocate capital across the Western Canadian Sedimentary Basin and the Eagle Ford. Production from the Ranger assets is approximately 70% weighted towards high netback light oil and is primarily operated which increases our ability to effectively allocate capital.

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

THIRD QUARTER HIGHLIGHTS

Baytex delivered solid operating and financial results in Q3/2023. Our third quarter results represent the first full quarter of operations following the Merger with Ranger and demonstrates the strength of our increased scale and diversified North American oil weighted portfolio. Production of 150,600 boe/d for Q3/2023 is consistent with expectations and reflects strong results from our drilling programs in Western Canada and the Eagle Ford in Texas. We invested $409.2 million on exploration and development expenditures and generated free cash flow(2) of $158.4 million during Q3/2023.

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

Exploration and development expenditures totaled $409.2 million in Q3/2023. In the U.S. we invested $302.1 million during Q3/2023 and production averaged 87,311 boe/d in Q3/2023 which is higher than 27,391 boe/d in Q3/2022 primarily due to the production contribution from the properties acquired from Ranger. We invested $107.1 million in Canada in Q3/2023 and generated production of 63,289 boe/d during Q3/2023 which was higher than 55,803 boe/d in Q3/2022 due to growth in our heavy oil and Duvernay assets.

Oil prices improved in Q3/2023 after OPEC production cuts and stable demand began to balance the market after concerns of an economic slowdown impacted crude oil prices during the first half of 2023. Despite recent improvements the WTI benchmark price of US$82.26/bbl for Q3/2023 was lower than US$91.56/bbl during Q3/2022 while the WCS differential averaged US$12.89/bbl and US$19.87/bbl over the same periods, respectively. Cash flows from operating activities of $444.0 million and adjusted funds flow[1] of $581.6 million for Q3/2023 reflect higher production and our increased scale following the Merger with Ranger relative to Q3/2022 when we generated cash flows from operating activities of $310.4 million and adjusted funds flow of $284.3 million.

Net debt[1] of $2.8 billion at September 30, 2023 increased from $987.4 million at December 31, 2022 due to the cash consideration paid and net debt assumed in conjunction with the Merger. We increased our shareholder returns to 50% of free cash flow[2] in conjunction with the closing of the Merger which allowed us to increase our share buyback program and introduce a dividend. The remainder of our free cash flow will be allocated to the balance sheet.

On June 23, 2023, we renewed our Normal Course Issuer Bid with the Toronto Stock Exchange for a share buyback program for up to 68.4 million shares (10% of our public float at the time). As of November 1, 2023, we repurchased and cancelled 10.4 million common shares at an average price of $5.82 per share for total consideration of $60.5 million. On October 2, 2023, we paid a quarterly cash dividend of CDN$0.0225 per share and, on November 2, 2023, the Board of Directors declared a quarterly cash dividend of CDN$0.0225 per share to be paid on January 2, 2024 for shareholders of record on December 15, 2023. These dividends are designated as “eligible dividends” for Canadian income tax purposes. For U.S. income tax purposes, Baytex’s dividends are considered “qualified dividends.”

2023 GUIDANCE

We are a well-capitalized and diversified oil-weighted North American E&P company with a strong free cash flow profile. We remain intensely focused on maintaining capital discipline and increasing shareholder returns on a per-share basis.

We continue to execute our 2023 plan and anticipate full-year 2023 production of 121,500 to 122,000 boe/d (previous guidance range of 120,500 to 122,500 boe/d). Production during the fourth quarter is expected to average 158,000 to 160,000 boe/d, 84% weighted to oil and NGLs (47% light oil, 24% heavy oil and 13% NGLs) and 16% natural gas. We anticipate full-year 2023 exploration and development expenditures of approximately $1,035 million, consistent with our previous guidance range of $1,005 to $1,045 million.

The following tables summarizes our 2023 guidance for production and exploration and development expenditures.

	H1/2023 Actual [3]	**Q3/2023 Actual**	**Q4/2023 Guidance**	**2023 Guidance**
Production (boe/d)	88,269	150,600	158,000 - 160,000	121,500 - 122,000
Exploration and development expenditures ($ millions)	$404	$409	~$222	~$1,035

(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) As announced on July 27, 2023. Includes Ranger from closing of the Merger on June 20, 2023.

The following table summarizes our 2023 guidance for expenses, leasing expenditures and asset retirement obligations. Guidance for interest expense is higher due largely to the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt.

	2023 Guidance [(1)]	**2023 Revised Guidance**
Expenses:		
Average royalty rate [(2)]	21.0 - 22.0%	No change
Operating [(3)]	$12.25 - $12.75/boe	~ $12.75/boe
Transportation [(3)]	$2.00 - $2.10/boe	~ $2.10/boe
General and administrative [(3)]	$80 million ($1.80/boe)	No change
Interest [(3)]	$150 million ($3.38/boe)	$156 million ($3.50/boe)
Leasing expenditures	$13 million	No change
Asset retirement obligations	$25 million	No change

(1) As announced on July 27, 2023. Includes Ranger from closing of the Merger on June 20, 2023.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Refer to Operating Expense, Transportation Expense, General and Administrative Expense and Financing and Interest Expense sections of this MD&A for description of the composition of these measures.

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 September 30					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**17,641**	**58,122**	**75,763**	16,509	16,738	33,247
Heavy oil	**35,204**	**—**	**35,204**	29,244	—	29,244
Natural Gas Liquids (NGL)	**2,102**	**15,902**	**18,004**	1,873	5,663	7,536
Total liquids (bbl/d)	**54,947**	**74,024**	**128,971**	47,626	22,401	70,027
Natural gas (mcf/d)	**50,058**	**79,722**	**129,780**	49,060	29,943	79,003
Total production (boe/d)	**63,289**	**87,311**	**150,600**	55,803	27,391	83,194
Production Mix						
Segment as a percent of total	**42 %**	**58 %**	**100 %**	67 %	33 %	100 %
Light oil and condensate	**28 %**	**67 %**	**50 %**	30 %	61 %	40 %
Heavy oil	**56 %**	**— %**	**23 %**	52 %	— %	35 %
NGL	**3 %**	**18 %**	**12 %**	3 %	21 %	9 %
Natural gas	**13 %**	**15 %**	**15 %**	15 %	18 %	16 %

	Nine Months Ended September 30					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**16,222**	**31,528**	**47,750**	16,582	16,855	33,437
Heavy oil	**34,076**	**—**	**34,076**	27,703	—	27,703
Natural Gas Liquids (NGL)	**1,804**	**9,514**	**11,318**	1,875	5,671	7,546
Total liquids (bbl/d)	**52,102**	**41,042**	**93,144**	46,160	22,526	68,686
Natural gas (mcf/d)	**47,077**	**49,710**	**96,787**	51,303	30,929	82,232
Total production (boe/d)	**59,948**	**49,327**	**109,275**	54,711	27,681	82,392
Production Mix						
Segment as a percent of total	**55 %**	**45 %**	**100 %**	66 %	34 %	100 %
Light oil and condensate	**27 %**	**64 %**	**44 %**	30 %	61 %	41 %
Heavy oil	**57 %**	**— %**	**31 %**	51 %	— %	34 %
NGL	**3 %**	**19 %**	**10 %**	3 %	20 %	9 %
Natural gas	**13 %**	**17 %**	**15 %**	16 %	19 %	16 %

Production was 150,600 boe/d for Q3/2023 and 109,275 boe/d for YTD 2023 compared to 83,194 boe/d for Q3/2022 and 82,392 boe/d for YTD 2022. Production for Q2/2023 and YTD 2023 was higher than the same periods of 2022 primarily due to the production contribution from the properties acquired from Ranger along with our successful development program in Canada.

In Canada, production was 63,289 boe/d for Q3/2023 and 59,948 boe/d for YTD 2023 compared to 55,803 boe/d for Q3/2022 and 54,711 boe/d for YTD 2022. The 7,486 boe/d increase in production for Q3/2023 and 5,237 boe/d for YTD reflects our strong well performance from our Clearwater development program at Peavine in addition to our light oil Duvernay development.

In the U.S., production was 87,311 boe/d for Q3/2023 and 49,327 boe/d for YTD 2023 compared to 27,391 boe/d for Q3/2022 and 27,681 boe/d for YTD 2022. The production contribution from the Merger with Ranger was the primary factor that resulted in a 59,920 boe/d increase in production for Q3/2023 and 21,646 boe/d for YTD 2023 relative to the same periods of 2022. Production from the acquired Eagle Ford assets is primarily operated and is weighted towards high netback light oil which resulted in a higher proportion of our total production being light oil in both periods of 2023.

Total production of 109,275 boe/d for YTD 2023 is consistent with expectations and we expect production of approximately 121,500 to 122,000 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 prices for crude oil improved during Q3/2023 as OPEC implemented new production cuts to stabilize the market after expectations for reduced crude oil demand impacted prices during the first half of 2023. Despite these recent improvements, the WTI benchmark price averaged US$82.26/bbl for Q3/2023 and US$77.39/bbl for YTD 2023 compared to Q3/2022 and YTD 2022 when WTI was higher due to uncertainty around global supply caused by Russia's invasion of Ukraine and averaged US$91.56/bbl and US$98.09/bbl, respectively.

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$84.10/bbl during Q3/2023 and US$78.84/bbl during YTD 2023 which is lower than US$96.15/bbl during Q3/2022 and US$101.76/bbl during YTD 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$1.84/bbl and US$1.45/bbl for Q3/2023 and YTD 2023 compared to premiums of US$4.59/bbl and US$3.67/bbl for Q3/2022 and YTD 2022, respectively. The MEH benchmark traded at a lower premium to WTI in both periods of 2023 as a result of reduced refinery demand on the Gulf Coast relative to the same periods of 2022.

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 levels in Western Canada along with North American refinery demand.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $107.93/bbl during Q3/2023 and $100.70/bbl during YTD 2023 compared to $116.79/bbl during Q3/2022 and $123.41/bbl during YTD 2022. Edmonton par traded at a discount to WTI of US$1.78/bbl for Q3/2023 and US$2.54/bbl for YTD 2023 which are similar to discounts of US$2.13/bbl for Q3/2022 and US$1.89/bbl for YTD 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 Q3/2023 and YTD 2023 averaged $93.02/bbl and $80.47/bbl, respectively, compared to $93.62/bbl and $105.65/bbl for the same periods of 2022. The WCS heavy oil differential was US$12.89/bbl in Q3/2023 and US$17.57/bbl in YTD 2023 compared to discounts of US$19.87/bbl for Q3/2022 and US$15.74/bbl for YTD 2022. Canadian heavy oil differentials were wider in 2023 due to higher heavy oil production in Western Canada in anticipation of additional egress capacity from the TMX pipeline expansion which has been delayed.

Natural Gas

Reduced demand for North American gas resulted in lower prices in both periods of 2023 relative to the same periods of 2022 which was impacted by geopolitical factors that caused higher global natural gas prices due to uncertainty of supply to Europe.

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. The NYMEX natural gas benchmark averaged US$2.55/mmbtu for Q3/2023 and US$2.69/mmbtu for YTD 2023 compared to US$8.20/mmbtu for Q3/2022 and US$6.77/mmbtu for YTD 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 $2.39/mcf during Q3/2023 and $3.03/mcf during YTD 2023 which is lower than $5.81/mcf for Q3/2022 and $5.56/mcf for YTD 2022.

The following tables compare select benchmark prices and our average realized selling prices for the three and nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30			Nine Months Ended September 30		
	2023	2022	Change	**2023**	2022	Change
Benchmark Averages						
WTI oil (US$/bbl) (1)	**82.26**	91.56	(9.30)	**77.39**	98.09	(20.70)
MEH oil (US$/bbl) (2)	**84.10**	96.15	(12.05)	**78.84**	101.76	(22.92)
MEH oil differential to WTI (US$/bbl)	**1.84**	4.59	(2.75)	**1.45**	3.67	(2.22)
Edmonton par oil ($/bbl) (3)	**107.93**	116.79	(8.86)	**100.70**	123.41	(22.71)
Edmonton par oil differential to WTI (US$/bbl)	**(1.78)**	(2.13)	0.35	**(2.54)**	(1.89)	(0.65)
WCS heavy oil ($/bbl) (4)	**93.02**	93.62	(0.60)	**80.47**	105.65	(25.18)
WCS heavy oil differential to WTI (US$/bbl)	**(12.89)**	(19.87)	6.98	**(17.57)**	(15.74)	(1.83)
AECO natural gas ($/mcf) (5)	**2.39**	5.81	(3.42)	**3.03**	5.56	(2.53)
NYMEX natural gas (US$/mmbtu) (6)	**2.55**	8.20	(5.65)	**2.69**	6.77	(4.08)
CAD/USD average exchange rate	**1.3410**	1.3059	0.0351	**1.3453**	1.2829	0.0624

(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 September 30					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) (1)	**$ 106.89**	**$ 109.09**	**$ 108.57**	$ 115.51	$ 122.43	$ 118.99
Heavy oil, net of blending and other expense ($/bbl) (2)	**84.43**	**—**	**84.43**	84.38	—	84.38
NGL ($/bbl) (1)	**30.75**	**28.04**	**28.36**	46.01	43.43	44.07
Natural gas ($/mcf) (1)	**2.72**	**3.20**	**3.01**	4.96	9.88	6.82
Total sales, net of blending and other expense ($/boe) (2)	**$ 79.93**	**$ 80.64**	**$ 80.34**	$ 84.30	$ 94.59	$ 87.68

	Nine Months Ended September 30					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl) (1)	**$ 100.46**	**$ 105.63**	**$ 103.87**	$ 121.19	$ 128.65	$ 124.95
Heavy oil, net of blending and other expense ($/bbl) (2)	**67.65**	**—**	**67.65**	95.10	—	95.10
NGL ($/bbl) (1)	**32.03**	**28.18**	**28.79**	46.29	44.91	45.25
Natural gas ($/mcf) (1)	**2.98**	**3.21**	**3.10**	5.56	8.29	6.58
Total sales, net of blending and other expense ($/boe) (2)	**$ 68.96**	**$ 76.19**	**$ 72.22**	$ 91.68	$ 96.79	$ 93.40

(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 $80.34/boe for Q3/2023 and $72.22/bbl for YTD 2023 compared to $87.68/boe for Q3/2022 and $93.40/boe for YTD 2022. In Canada, our realized price of $79.93/boe for Q3/2023 was $4.37/boe lower than $84.30/boe for Q3/2022. Our realized price in the U.S. was $80.64/boe in Q3/2023 which is $13.95/boe lower than $94.59/boe in Q3/2022. Lower North American benchmark oil prices was the primary factor that resulted in lower realized pricing for our operations in Canada and the U.S. in Q3/2023 and YTD 2023 relative to the same periods 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 $106.89/bbl for Q3/2023 and $100.46/bbl for YTD 2023 compared to $115.51/bbl for Q3/2022 and $121.19/bbl for YTD 2022. The decrease in our realized light oil and condensate price for Q3/2023 and YTD 2023 was primarily a result of lower benchmark prices and represents discounts to the Edmonton par price of $1.04/bbl and $0.24/bbl for Q3/2023 and YTD 2023, respectively, which are narrower than discounts of $1.28/bbl in Q3/2022 and $2.22/bbl in YTD 2022 which reflects strong realized pricing on our Viking and Duvernay production in 2023.

We compare the price received for our U.S. light oil and condensate production to the MEH benchmark. Our realized light oil and condensate price averaged $109.09/bbl for Q3/2023 and $105.63/bbl for YTD 2023 compared to $122.43/bbl for Q3/2022 and $128.65/bbl for YTD 2022. Expressed in U.S. dollars, our realized light oil and condensate price of US$81.35/bbl for Q3/2023 and US$78.52/bbl for YTD 2023 represents discounts to MEH of US$2.75/bbl and US$0.32/bbl for Q3/2023 and YTD 2023, respectively, compared to US$2.40/bbl for Q3/2022 and US$1.48/bbl for YTD 2022. The discount US$0.32/bbl for YTD 2023 reflects a significant proportion of our YTD 2023 production occurring in Q3/2023 when the MEH benchmark was higher while the discount of US$2.75/bbl for Q3/2023 is consistent with expectations and representative of the pricing we expect to receive on our total Eagle Ford production.

Our realized heavy oil price, net of blending and other expense(1) averaged $84.43/bbl in Q3/2023 and $67.65/bbl in YTD 2023 compared to $84.38/bbl in Q3/2022 and $95.10/bbl in YTD 2022. Our realized heavy oil, net of blending and other expense for Q3/2023 and YTD 2023 was $0.05/bbl and $27.45/bbl lower relative to Q3/2022 and YTD 2022, respectively, which is relatively consistent with a $0.60/bbl and $25.18/bbl decrease in the WCS benchmark price over the same periods.

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 $28.36/bbl in Q3/2023 or 26% of WTI (expressed in Canadian dollars) and $28.79/bbl in YTD 2023 or 28% of WTI (expressed in Canadian dollars) compared to $44.07/bbl or 37% of WTI (expressed in Canadian dollars) in Q3/2022 and $45.25/bbl or 36% of WTI (expressed in Canadian dollars) in YTD 2022. Our realized NGL price in Canada and the U.S. was lower as a percentage of WTI in Q3/2023 and YTD 2023 due to lower demand for NGL products relative to the same periods of 2022.

We compare our realized natural gas price in the U.S. to the NYMEX benchmark and to the AECO benchmark price in Canada. A portion of our natural gas sales in Canada and the U.S. are based on the respective daily index prices which fluctuate independently from the associated monthly index prices. Our realized natural gas price(2) in Canada was $2.72/mcf for Q3/2023 and $2.98/mcf for YTD 2023 compared to $4.96/mcf in Q3/2022 and $5.56/mcf for YTD 2022. In the U.S., our realized natural gas price was US$2.39/mcf for Q3/2023 and US$2.39/mcf for YTD 2023 compared to US$7.57/mcf for Q3/2022 and US$6.46/mcf for YTD 2022. The decrease in our realized gas price in Canada and the U.S. is relatively consistent with the decreases in the AECO monthly and NYMEX monthly benchmark prices in 2023 compared to the same periods of 2022.

(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 September 30					
	2023			2022		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 173,475**	**$ 583,304**	**$ 756,779**	$ 175,447	$ 188,521	$ 363,968
Heavy oil	**323,272**	**—**	**323,272**	267,958	—	267,958
NGL	**5,945**	**41,027**	**46,972**	7,929	22,627	30,556
Total oil sales	**502,692**	**624,331**	**1,127,023**	451,334	211,148	662,482
Natural gas sales	**12,526**	**23,461**	**35,987**	22,374	27,209	49,583
Total petroleum and natural gas sales	**515,218**	**647,792**	**1,163,010**	473,708	238,357	712,065
Blending and other expense	**(49,830)**	**—**	**(49,830)**	(40,945)	—	(40,945)
Total sales, net of blending and other expense [(1)]	**$ 465,388**	**$ 647,792**	**$ 1,113,180**	$ 432,763	$ 238,357	$ 671,120

	Nine Months Ended September 30					
	2023			2022		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 444,894**	**$ 909,159**	**$ 1,354,053**	$ 548,588	$ 591,946	$ 1,140,534
Heavy oil	**791,806**	**—**	**791,806**	858,497	—	858,497
NGL	**15,777**	**73,192**	**88,969**	23,701	69,529	93,230
Total oil sales	**1,252,477**	**982,351**	**2,234,828**	1,430,786	661,475	2,092,261
Natural gas sales	**38,654**	**43,624**	**82,278**	77,823	69,975	147,798
Total petroleum and natural gas sales	**1,291,131**	**1,025,975**	**2,317,106**	1,508,609	731,450	2,240,059
Blending and other expense	**(162,506)**	**—**	**(162,506)**	(139,280)	—	(139,280)
Total sales, net of blending and other expense [(1)]	**$ 1,128,625**	**$ 1,025,975**	**$ 2,154,600**	$ 1,369,329	$ 731,450	$ 2,100,779

(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 $1.1 billion for Q3/2023 increased $442.1 million from $671.1 million reported for Q3/2022 while total sales, net of blending and other expense, of $2.2 billion for YTD 2023 increased $53.8 million from $2.1 billion reported for YTD 2022. The Merger with Ranger along with higher production from our successful development programs resulted in an increase in total sales in both periods of 2023 relative to the same periods of 2022 which was partially offset by the effect of lower benchmark prices.

In Canada, total sales, net of blending and other expense, was $465.4 million for Q3/2023 which is an increase of $32.6 million from $432.8 million reported for Q3/2022. The increase in total petroleum and natural gas sales was the result of higher production which resulted in a $58.1 million increase in total sales, net of blending and other expense, relative to Q3/2022. The effect of higher production was partially offset by lower realized pricing for Q3/2023 relative to Q3/2022 which resulted in a $25.4 million decrease in total sales, net of blending and other expense. Lower benchmark prices was the primary factor contributing to our total sales, net of blending and other expense, decreasing to $1,128.6 million in YTD 2023 from $1,369.3 million in YTD 2022 as Canadian production was higher in YTD 2023 relative to YTD 2022.

In the U.S., petroleum and natural gas sales were $647.8 million for Q3/2023 which is an increase of $409.4 million from $238.4 million reported for Q3/2022. Higher production in Q3/2023 relative to Q3/2022 contributed to a $521.4 million increase in total sales which was partially offset by lower realized pricing which resulted in a $112.0 million decrease in total sales for Q3/2023 relative to Q3/2022. Higher production in YTD 2023 resulted in petroleum and natural gas sales of $1,026.0 million for YTD 2023 compared to $731.5 million in YTD 2022 despite lower realized prices in YTD 2023 relative to YTD 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 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 and nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30					
	2023			2022		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 64,238**	**$ 175,811**	**$ 240,049**	$ 75,901	$ 71,093	$ 146,994
Average royalty rate [(1)(2)]	**13.8 %**	**27.1 %**	**21.6 %**	17.5 %	29.8 %	21.9 %
Royalties per boe [(3)]	**$ 11.03**	**$ 21.89**	**$ 17.33**	$ 14.78	$ 28.21	$ 19.21

	Nine Months Ended September 30					
	2023			2022		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 155,402**	**$ 285,820**	**$ 441,222**	$ 224,710	$ 216,563	$ 441,273
Average royalty rate [(1)(2)]	**13.8 %**	**27.9 %**	**20.5 %**	16.4 %	29.6 %	21.0 %
Royalties per boe [(3)]	**$ 9.50**	**$ 21.22**	**$ 14.79**	$ 15.04	$ 28.66	$ 19.62

(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 Q3/2023 were $240.0 million or 21.6% of total sales, net of blending and other expense, compared to $147.0 million or 21.9% for Q3/2022. Total royalties for YTD 2023 were $441.2 million or 20.5% of total sales, net of blending and other expense, compared to $441.3 million or 21.0% for YTD 2022. Our royalty rates of 21.6% for Q3/2023 and 20.5% for YTD 2023 were lower than 21.9% for Q3/2022 and 21.0% for YTD 2022.

Our Canadian royalty rates of 13.8% for Q3/2023 and 13.8% for YTD 2023 were lower than 17.5% for Q3/2022 and 16.4% for YTD 2022 due to lower benchmark commodity prices which resulted in a lower royalty rate on our Canadian properties in 2023 relative to 2022. In the U.S., royalties averaged 27.1% of total sales for Q3/2023 and 27.9% for YTD 2023 respectively, which is slightly lower than 29.8% for Q3/2022 and 29.6% for YTD 2022 due to the production contributed by the acquired Ranger assets which have a lower royalty rate relative to our legacy non-operated Eagle Ford assets.

Our average royalty rate of 20.5% for YTD 2023 is consistent with expectations and is slightly below our annual guidance range of 21.0 - 22.0% which reflects the royalty rate on the production contributed by the properties acquired from Ranger through the remainder of 2023.

OPERATING EXPENSE

	Three Months Ended September 30					
	2023			2022		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 93,065**	**$ 81,054**	**$ 174,119**	$ 83,141	$ 26,998	$ 110,139
Operating expense per boe [(1)]	**$ 15.98**	**$ 10.09**	**$ 12.57**	$ 16.19	$ 10.71	$ 14.39

	Nine Months Ended September 30					
	2023			2022		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 275,599**	**$ 130,366**	**$ 405,965**	$ 244,152	$ 74,179	$ 318,331
Operating expense per boe [(1)]	**$ 16.84**	**$ 9.68**	**$ 13.61**	$ 16.35	$ 9.82	$ 14.15

(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 $174.1 million ($12.57/boe) for Q3/2023 and $406.0 million ($13.61/boe) for YTD 2023 compared to $110.1 million ($14.39/boe) for Q3/2022 and $318.3 million ($14.15/boe) for YTD 2022. Total operating expense for both periods of 2023 increased relative to the same periods of 2022 while per boe operating costs were lower due to the properties acquired from Ranger.

In Canada, operating expense was $93.1 million ($15.98/boe) for Q3/2023 and $275.6 million ($16.84/boe) for YTD 2023 compared to $83.1 million ($16.19/boe) for Q3/2022 and $244.2 million ($16.35/boe) for YTD 2022. Total operating expenses were higher in Canada as a result of higher production as per boe operating costs were relatively consistent in both periods of 2023 relative to the same periods of 2022.

U.S. operating expense was $81.1 million ($10.09/boe) for Q3/2023 and $130.4 million ($9.68/boe) for YTD 2023 compared to $27.0 million ($10.71/boe) for Q3/2022 and $74.2 million ($9.82/boe) in YTD 2022. Total operating expense in the U.S. was higher in both periods of 2023 relative to the same periods of 2022 with the addition of production from the Merger with Ranger. Per boe operating expense in the U.S., expressed in U.S. dollars, was US$7.52/boe in Q3/2023 and US$7.20/boe in YTD 2023 which was lower than US$8.20/boe for Q3/2022 and US$7.65/boe in YTD 2022 which reflects lower workover and maintenance costs on our non-operated acreage along with the lower per unit operating cost associated with the additional production from the properties acquired from Ranger.

Operating expense of $13.61/boe for YTD 2023 is consistent with expectations and is expected to be within our annual guidance range of approximately $12.75/boe which is a result of lower per unit operating costs on our operated Eagle Ford production for the remainder of 2023.

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. Transportation expense in our U.S. operations is primarily the costs incurred to deliver our production via truck or pipeline to a centralized sales point.

The following table compares our transportation expense for the three and nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30					
	2023			2022		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 16,075**	**$ 11,908**	**$ 27,983**	$ 12,771	$ —	$ 12,771
Transportation expense per boe [1]	**$ 2.76**	**$ 1.48**	**$ 2.02**	$ 2.49	$ —	$ 1.67

	Nine Months Ended September 30					
	2023			2022		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 46,320**	**$ 13,242**	**$ 59,562**	$ 33,744	$ —	$ 33,744
Transportation expense per boe [1]	**$ 2.83**	**$ 0.98**	**$ 2.00**	$ 2.26	$ —	$ 1.50

(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 $28.0 million ($2.02/boe) for Q3/2023 and $59.6 million ($2.00/boe) for YTD 2023 compared to $12.8 million ($1.67/boe) for Q3/2022 and $33.7 million ($1.50/boe) for YTD 2022. In Canada, total transportation expense and per unit costs are higher in Q3/2023 and YTD 2023 as a result of additional heavy oil production along with higher trucking rates relative to the same periods of 2022. Transportation expense in the U.S. is consistent with expectations for Q3/2023 and YTD 2023 and reflects trucking and pipeline transportation costs on our Eagle Ford operations acquired from Ranger. Per unit transportation expense of $2.00/boe for YTD 2023 is lower than our annual guidance range of approximately $2.10/boe which reflects the transportation costs associated with the properties acquired from Ranger.

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 $49.8 million for Q3/2023 and $162.5 million for YTD 2023 compared to $40.9 million for Q3/2022 and $139.3 million for YTD 2022. The increase in blending and other expense is primarily a result of higher heavy oil production and pipeline shipments in Q3/2023 and YTD 2023 relative to the same periods of 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 revenue. 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 and nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2023**	2022	Change	**2023**	2022	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ 2,130**	$ (66,582)	$ 68,712	**$ 23,909**	$ (258,180)	$ 282,089
Natural gas	**(75)**	(9,826)	9,751	**(74)**	(26,636)	26,562
Total	**$ 2,055**	$ (76,408)	$ 78,463	**$ 23,835**	$ (284,816)	$ 308,651
Unrealized financial derivatives (loss) gain						
Crude oil	**$ (31,903)**	$ 189,613	$ (221,516)	**$ (39,817)**	$ 98,111	$ (137,928)
Natural gas	**1,207**	4,018	(2,811)	**(1,072)**	(3,253)	2,181
Equity total return swap ("Equity TRS")	**—**	(3,160)	3,160	**—**	(1,880)	1,880
Total	**$ (30,696)**	$ 190,471	$ (221,167)	**$ (40,889)**	$ 92,978	$ (133,867)
Total financial derivatives (loss) gain						
Crude oil	**$ (29,773)**	$ 123,031	$ (152,804)	**$ (15,908)**	$ (160,069)	$ 144,161
Natural gas	**1,132**	(5,808)	6,940	**(1,146)**	(29,889)	28,743
Equity TRS	**—**	(3,160)	3,160	**—**	(1,880)	1,880
Total	**$ (28,641)**	$ 114,063	$ (142,704)	**$ (17,054)**	$ (191,838)	$ 174,784

We recorded a total financial derivative loss of $28.6 million for Q3/2023 and $17.1 million for YTD 2023 compared to a gain of $114.1 million for Q3/2022 and a loss $191.8 million for YTD 2022. The realized financial derivatives gain of $2.1 million for Q3/2023 was primarily a result of the WCS differential market prices settling at levels wider than those set in our derivative contracts. The realized financial derivatives gain of $23.8 million for YTD 2023 also includes gains on WTI crude oil contracts that were in place during the first half of 2023. The unrealized loss of $30.7 million for Q3/2023 and $40.9 million for YTD 2023 reflect changes in forecasted crude oil pricing used to revalue the unsettled notional volume outstanding on our crude oil contracts in place at September 30, 2023 relative to June 30, 2023 and December 31, 2022. The fair value of our financial derivative contracts resulted in a net liability of $6.1 million at September 30, 2023 compared to a net asset of $24.6 million at June 30, 2023 and a net asset of $10.1 million at December 31, 2022.

We had the following commodity financial derivative contracts outstanding subsequent to September 30, 2023 and as of November 2, 2023:

	Period	Volume	Price/Unit [1]	Index
Oil				
Basis differential [2]	Oct 2023 to Dec 2023	1,500 bbl/d	WTI less US$2.50/bbl	MSW
Basis differential [2]	Jan 2024 to Dec 2024	1,500 bbl/d	WTI less US$2.65/bbl	MSW
Basis differential [2]	Oct 2023 to Dec 2023	8,000 bbl/d	WTI less US$13.96/bbl	WCS
Basis differential [2]	Oct 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
Basis differential [2]	Jan 2024 to Jun 2024	4,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.10/bbl	WCS
Put option	Oct 2023 to Dec 2023	5,000 bbl/d	US$60.00	WTI
Collar	Oct 2023 to Dec 2023	30,589 bbl/d	US$60.00/US$100.00	WTI
Collar	Jan 2024 to Jun 2024	24,500 bbl/d	US$60.00/US$100.00	WTI
Collar	Jan 2024 to Mar 2024	10,400 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$90.21	WTI
Collar	Apr 2024 to Jun 2024	11,750 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$94.15	WTI
Collar	July 2024 to Dec 2024	5,000 bbl/d	US$60.00/US$100.00	WTI
Collar [3]	July 2024 to Sep 2024	10,000 bbl/d	US$60.00/US$100.00	WTI
Collar [3]	Oct 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$100.00	WTI
Collar [3]	July 2024 to Dec 2024	5,000 bbl/d	US$60.00/US$100.00	WTI
Natural Gas				
Basis differential [2]	Oct 2023 to Dec 2023	11,413 mmbtu/d	Baytex pays: NYMEX Baytex receives: HSC less US$0.1525/mmbtu	HSC
Fixed Sell	Oct 2023 to Mar 2024	3,500 mmbtu/d	US$3.5025	NYMEX
Collar	Oct 2023 to Dec 2023	11,413 mmbtu/d	US$2.50/US$2.68	NYMEX
Collar	Jan 2024 to Mar 2024	11,538 mmbtu/d	US$2.50/US$3.65	NYMEX
Collar	Apr 2024 to Jun 2024	11,538 mmbtu/d	US$2.33/US$3.00	NYMEX
Collar	Jan 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.06	NYMEX
Collar	Jan 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.09	NYMEX
Collar	Jan 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.10	NYMEX
Collar	Jan 2024 to Dec 2024	8,500 mmbtu/d	US$3.00/US$4.15	NYMEX
Collar	Jan 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.19	NYMEX
Natural Gas Liquids				
Fixed Sell	Oct 2023 to Mar 2024	34,364 gallon/d	US$0.2280/gallon	Mt. Belvieu Non-TET Ethane

(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) Contract entered subsequent to September 30, 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 and nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30					
	2023			2022		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**63,289**	**87,311**	**150,600**	55,803	27,391	83,194
Operating netback:						
Total sales, net of blending and other expense (1)	**$ 79.93**	**$ 80.64**	**$ 80.34**	$ 84.30	$ 94.59	$ 87.68
Less:						
Royalties (2)	**(11.03)**	**(21.89)**	**(17.33)**	(14.78)	(28.21)	(19.21)
Operating expense (2)	**(15.98)**	**(10.09)**	**(12.57)**	(16.19)	(10.71)	(14.39)
Transportation expense (2)	**(2.76)**	**(1.48)**	**(2.02)**	(2.49)	—	(1.67)
Operating netback (1)	**$ 50.16**	**$ 47.18**	**$ 48.42**	$ 50.84	$ 55.67	$ 52.41
Realized financial derivatives gain (loss) (3)	**—**	**—**	**0.15**	—	—	(9.98)
Operating netback after financial derivatives (1)	**$ 50.16**	**$ 47.18**	**$ 48.57**	$ 50.84	$ 55.67	$ 42.43

	Nine Months Ended September 30					
	2023			2022		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**59,948**	**49,327**	**109,275**	54,711	27,681	82,392
Operating netback:						
Total sales, net of blending and other expense (1)	**$ 68.96**	**$ 76.19**	**$ 72.22**	$ 91.68	$ 96.79	$ 93.40
Less:						
Royalties (2)	**(9.50)**	**(21.22)**	**(14.79)**	(15.04)	(28.66)	(19.62)
Operating expense (2)	**(16.84)**	**(9.68)**	**(13.61)**	(16.35)	(9.82)	(14.15)
Transportation expense (2)	**(2.83)**	**(0.98)**	**(2.00)**	(2.26)	—	(1.50)
Operating netback (1)	**$ 39.79**	**$ 44.31**	**$ 41.82**	$ 58.03	$ 58.31	$ 58.13
Realized financial derivatives gain (loss) (3)	**—**	**—**	**0.80**	—	—	(12.66)
Operating netback after financial derivatives (1)	**$ 39.79**	**$ 44.31**	**$ 42.62**	$ 58.03	$ 58.31	$ 45.47

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Refer to Royalties, Operating Expense and Transportation Expense sections in this MD&A for a description of the composition these measures.
(3) Calculated as realized financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

Our operating netback was $48.42/boe for Q3/2023 and $41.82/boe for YTD 2023 compared to $52.41/boe for Q3/2022 and $58.13/boe for YTD 2022 due to lower benchmark pricing in Canada and the U.S. which resulted in a decrease in per unit sales net of royalties. Total operating and transportation expense of $14.59/boe for Q3/2023 and $15.61/boe for YTD 2023 were relatively consistent with $16.06/boe for Q3/2022 and $15.65/boe for YTD 2022 which reflects lower operating and transportation costs on the Eagle Ford properties acquired from Ranger which offset the effect of inflation experienced in our operations prior to closing of the Merger on June 20, 2023. Operating netback including realized gains (losses) on financial derivatives was $48.57/boe for Q3/2023 and $42.62/boe for YTD 2023 compared to $42.43/boe for Q3/2022 and $45.47/boe for YTD 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 and nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2023**	2022	Change	**2023**	2022	Change
Gross general and administrative expense	**$ 25,970**	$ 13,782	$ 12,188	**$ 56,863**	$ 39,511	$ 17,352
Overhead recoveries	**(5,434)**	(1,779)	(3,655)	**(9,353)**	(4,186)	(5,167)
General and administrative expense	**$ 20,536**	$ 12,003	$ 8,533	**$ 47,510**	$ 35,325	$ 12,185
General and administrative expense per boe (1)	**$ 1.48**	$ 1.57	$ (0.09)	**$ 1.59**	$ 1.57	$ 0.02

(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 $20.5 million ($1.48/boe) for Q3/2023 and $47.5 million ($1.59/boe) for YTD 2023 compared to $12.0 million ($1.57/boe) for Q3/2022 and $35.3 million ($1.57/boe) for YTD 2022. G&A expense for Q3/2023 and YTD 2023 is consistent with expectations and was higher than the comparative periods of 2022 due to the increase in staffing levels and integration costs associated with the Merger with Ranger. G&A expense of $1.59/boe during YTD 2023 is lower than our annual guidance of $75 million ($1.80/boe) which reflects the additional staffing levels and administrative costs associated with the Merger with Ranger.

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 accretion on our debt issue costs and asset retirement obligations. Financing and interest expense varies depending on debt levels outstanding during the period, 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 and nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2023**	2022	Change	**2023**	2022	Change
Interest on credit facilities	**$ 21,671**	$ 5,788	$ 15,883	**$ 35,422**	$ 12,897	$ 22,525
Interest on long-term notes	**34,664**	13,935	20,729	**67,323**	47,635	19,688
Interest on lease obligations	**160**	51	109	**$ 380**	$ 143	237
Cash interest	**$ 56,495**	$ 19,774	$ 36,721	**$ 103,125**	$ 60,675	$ 42,450
Accretion of debt issue costs	**6,539**	1,242	5,297	**8,910**	4,671	4,239
Accretion of asset retirement obligations	**5,031**	4,412	619	**14,252**	11,403	2,849
Early redemption expense	**—**	325	(325)	**—**	325	(325)
Financing and interest expense	**$ 68,065**	$ 25,753	$ 42,312	**$ 126,287**	$ 77,074	$ 49,213
Cash interest per boe (1)	**$ 4.08**	$ 2.58	$ 1.50	**$ 3.46**	$ 2.70	$ 0.76
Financing and interest expense per boe (1)	**$ 4.91**	$ 3.36	$ 1.55	**$ 4.23**	$ 3.43	$ 0.80

(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 $68.1 million ($4.91/boe) for Q3/2023 and $126.3 million ($4.23/boe) for YTD 2023 compared to $25.8 million ($3.36/boe) for Q3/2022 and $77.1 million ($3.43/boe) for YTD 2022. Higher interest costs in 2023 relative to 2022 reflects the additional debt outstanding as a result of the Merger with Ranger in addition to an increase in interest rates.

Cash interest was $56.5 million ($4.08/boe) for Q3/2023 and $103.1 million ($3.46/boe) for YTD 2023 compared to $19.8 million ($2.58/boe) for Q3/2022 and $60.7 million ($2.70/boe) for YTD 2022. Cash interest was higher in both periods of 2023 relative to the same periods of 2022 as a result of the additional debt outstanding due to the Merger which included the issuance of US$800.0 million aggregate principal amount of long-term notes. Interest on our credit facilities in Q3/2023 and YTD 2023 was higher than the same periods of 2022 primarily due to the increase in benchmark borrowing rate along with an increase in the principal amounts outstanding. The weighted average interest rate applicable to our credit facilities was 7.8% for Q3/2023 and 7.3% for YTD 2023 which is higher than 4.1% for Q3/2022 and 3.1% for YTD 2022.

Accretion of asset retirement obligations of $5.0 million for Q3/2023 and $14.3 million for YTD 2023 was higher than $4.4 million for Q3/2022 and $11.4 million for YTD 2022 due to a higher discount rate used in both periods of 2023. Accretion of debt issue costs was higher in both periods of 2023 relative to the comparative periods of 2022 due to the increase in debt issue costs associated with the increased credit facilities and new long-term notes issued to fund the Merger with Ranger.

We have updated our cash interest annual guidance for 2023 to $156 million ($3.50/boe) which reflects higher interest rates on our credit facilities along with the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt.

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 $0.4 million for Q3/2023 and $0.9 million for YTD 2023 compared to $6.6 million for Q3/2022 and $17.3 million for YTD 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 and nine months ended September 30, 2023 and 2022.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2023**	2022	Change	**2023**	2022	Change
Depletion and depreciation	**$ 319,731**	$ 144,177	$ 175,554	**$ 661,874**	$ 427,254	$ 234,620
Depletion and depreciation per boe [1]	**$ 23.08**	$ 18.84	$ 4.24	**$ 22.19**	$ 18.99	$ 3.20

(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 $319.7 million ($23.08/boe) for Q3/2023 and $661.9 million ($22.19/boe) for YTD 2023 compared to $144.2 million ($18.84/boe) for Q3/2022 and $427.3 million ($18.99/boe) for YTD 2022. Total depletion and depreciation expense and depletion and depreciation per boe were higher in Q3/2023 and YTD 2023 relative to Q3/2022 and YTD 2022 as a result of the oil and gas properties acquired from Ranger which have a higher depletion rate than our other properties which is primarily driven by higher future development costs.

IMPAIRMENT

We did not identify indicators of impairment or impairment reversal for any of our cash generating units ("CGUs") at September 30, 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 along with the share based compensation plan assumed from Ranger in June 2023. 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 associated with cash-settled awards 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 $14.7 million for Q3/2023 and $41.4 million for YTD 2023 compared to $3.1 million for Q3/2022 and $10.0 million for YTD 2022. SBC expense for YTD 2023 includes $16.2 million of non-cash expense related to awards assumed and settled in Baytex common shares in conjunction with the Merger. Regular expensing of compensation awards is considered a cash expense as we intend to settle currently outstanding and future awards in cash while Baytex is repurchasing shares as part of its shareholder return program.

Cash SBC expense of $14.7 million for Q3/2023 reflects additional awards outstanding following the Merger along with an increase in our share price at September 30, 2023 compared to June 30, 2023 which resulted in higher cash SBC expense compared to $3.1 million for Q3/2022 when we had a higher notional amount outstanding under the equity total return swaps. 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. Cash SBC expense of $25.2 million for YTD 2023 was higher than $7.2 million for YTD 2022 due to additional awards outstanding along with the increase in our share price in addition to the reduced notional amount of equity return swaps outstanding in 2023.

FOREIGN EXCHANGE

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

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for exchange rates)	**2023**	2022	Change	**2023**	2022	Change
Unrealized foreign exchange loss	**$ 42,392**	$ 39,799	$ 2,593	**$ 29,299**	$ 52,750	$ (23,451)
Realized foreign exchange loss (gain)	**290**	(894)	1,184	**1,381**	(481)	1,862
Foreign exchange loss	**$ 42,682**	$ 38,905	$ 3,777	**$ 30,680**	$ 52,269	$ (21,589)
CAD/USD exchange rates:						
At beginning of period	**1.3238**	1.2872		**1.3534**	1.2656	
At end of period	**1.3537**	1.3700		**1.3537**	1.3700	

We recorded a foreign exchange loss of $42.7 million for Q3/2023 and $30.7 million for YTD 2023 compared to a loss of $38.9 million for Q3/2022 and $52.3 million for YTD 2022.

The unrealized foreign exchange loss of $42.4 million for Q3/2023 and $29.3 million for YTD 2023 is related to changes in the reported amount of our long-term notes and credit facilities due to a weakening of the Canadian dollar relative to the U.S. dollar at September 30, 2023 compared to June 30, 2023 and December 31, 2022. The unrealized foreign exchange loss for Q3/2022 and YTD 2022 was also due to a weakening of the Canadian dollar relative to the U.S dollar resulting in changes in the reported amount of our long-term notes outstanding at September 30, 2022 compared to June 30, 2022 and 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 $0.3 million for Q3/2023 and $1.4 million for YTD 2023 compared to a loss of $0.9 million for Q3/2022 and $0.5 million for YTD 2022.

INCOME TAXES

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2023**	2022	Change	**2023**	2022	Change
Current income tax expense	**$ 808**	$ 703	$ 105	**$ 3,278**	$ 2,753	$ 525
Deferred income tax expense (recovery)	**48,007**	18,475	29,532	**(114,830)**	(8,937)	(105,893)
Total income tax expense (recovery)	**$ 48,815**	$ 19,178	$ 29,637	**$ (111,552)**	$ (6,184)	$ (105,368)

Current income tax expense was $0.8 million for Q3/2023 and $3.3 million for YTD 2023 compared to $0.7 million for Q3/2022 and $2.8 million for YTD 2022.

We recorded a deferred tax expense of $48.0 million for Q3/2023 and a recovery of $114.8 million for YTD 2023 compared to an expense of $18.5 million for Q3/2022 and a recovery $8.9 million for YTD 2022. The deferred tax expense in Q3/2023 is due to income generated on our Canadian and U.S. operations for the period. The deferred tax recovery in YTD 2023 is primarily related to the effects of the transaction structuring for the Merger in Q2/2023 partially offset by income generated on our Canadian and U.S. operations for the period.

As disclosed in the 2022 annual financial statements, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the "CRA") in June 2016 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. In July 2023, Baytex received a letter from the Appeals Division of the CRA proposing to confirm the reassessments. Baytex submitted a response to this proposal in October 2023.

Baytex has received advice from its tax advisors that it should be entitled to use the non-capital loss deductions and remains confident that the original tax filings are correct. As such, Baytex has not recognized any provision in its unaudited interim consolidated financial statements with respect to the reassessments. In the event that Baytex is unsuccessful, Baytex would be required to remit taxes plus interest.

NET INCOME AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income or loss for the three and nine months ended September 30, 2023 and 2022 are set forth in the following table.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2023**	2022	Change	**2023**	2022	Change
Petroleum and natural gas sales	**$ 1,163,010**	$ 712,065	$ 450,945	**$ 2,317,106**	$ 2,240,059	$ 77,047
Royalties	**(240,049)**	(146,994)	(93,055)	**(441,222)**	(441,273)	51
Revenue, net of royalties	**922,961**	565,071	357,890	**1,875,884**	1,798,786	77,098
Expenses						
Operating	**(174,119)**	(110,139)	(63,980)	**(405,965)**	(318,331)	(87,634)
Transportation	**(27,983)**	(12,771)	(15,212)	**(59,562)**	(33,744)	(25,818)
Blending and other	**(49,830)**	(40,945)	(8,885)	**(162,506)**	(139,280)	(23,226)
Operating netback (1)	**$ 671,029**	$ 401,216	$ 269,813	**$ 1,247,851**	$ 1,307,431	$ (59,580)
General and administrative	**(20,536)**	(12,003)	(8,533)	**(47,510)**	(35,325)	(12,185)
Cash interest	**(56,495)**	(19,774)	(36,721)	**(103,125)**	(60,675)	(42,450)
Realized financial derivatives gain (loss)	**2,055**	(76,408)	78,463	**23,835**	(284,816)	308,651
Realized foreign exchange (loss) gain	**(290)**	894	(1,184)	**(1,381)**	481	(1,862)
Other income (expense)	**1,367**	(6,499)	7,866	**1,013**	(7,500)	8,513
Current income tax expense	**(808)**	(703)	(105)	**(3,278)**	(2,753)	(525)
Cash share-based compensation	**(14,699)**	(2,435)	(12,264)	**(25,203)**	(7,244)	(17,959)
Adjusted funds flow (2)	**$ 581,623**	$ 284,288	$ 297,335	**$ 1,092,202**	$ 909,599	$ 182,603
Transaction costs	**(2,263)**	—	(2,263)	**(43,966)**	—	(43,966)
Exploration and evaluation	**(409)**	(6,566)	6,157	**(941)**	(17,346)	16,405
Depletion and depreciation	**(319,731)**	(144,177)	(175,554)	**(661,874)**	(427,254)	(234,620)
Non-cash share-based compensation	**—**	(637)	637	**(16,237)**	(2,715)	(13,522)
Non-cash financing and accretion	**(11,570)**	(5,979)	(5,591)	**(23,162)**	(16,399)	(6,763)
Non-cash other income (expense)	**—**	1,276	(1,276)	**1,271**	2,741	(1,470)
Unrealized financial derivatives (loss) gain	**(30,696)**	190,471	(221,167)	**(40,889)**	92,978	(133,867)
Unrealized foreign exchange gain (loss)	**(42,392)**	(39,799)	(2,593)	**(29,299)**	(52,750)	23,451
Gain (loss) on dispositions	**875**	4,566	(3,691)	**539**	5,007	(4,468)
Deferred income tax recovery (expense)	**(48,007)**	(18,475)	(29,532)	**114,830**	8,937	105,893
Net income for the period	**$ 127,430**	$ 264,968	$ (137,538)	**$ 392,474**	$ 502,798	$ (110,324)

(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 $581.6 million for Q3/2023 and $1,092.2 million for YTD 2023 compared to $284.3 million for Q3/2022 and $909.6 million for YTD 2022. The increase in adjusted funds flow for Q3/2023 was primarily due to higher production from the Merger with Ranger which resulted in a $269.8 million increase in operating netback relative to Q3/2022. The $182.6 million increase in adjusted funds flow for YTD 2023 relative to YTD 2022 reflects a $59.6 million decrease in operating netback due to lower commodity prices along with a $42.5 million increase in cash interest which were more than offset by a $308.7 million increase in realized gains on financial derivatives. We reported net income of $127.4 million for Q3/2023 and $392.5 million for YTD 2023 compared to net income of $265.0 million reported for Q3/2022 and $502.8 million for YTD 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 gain of $112.0 million for Q3/2023 and $65.0 million for YTD 2023 relates to the change in value of our U.S. net assets and is due to the weakening of the Canadian dollar relative to the U.S. dollar at September 30, 2023 compared to June 30, 2023 and December 31, 2022. The CAD/USD exchange rate was 1.3537 CAD/USD as at September 30, 2023 compared to 1.3238 CAD/USD at June 30, 2023 and 1.3534 CAD/USD at December 31, 2022.

CAPITAL EXPENDITURES

Capital expenditures for the three and nine months ended September 30, 2023 and 2022 are summarized as follows.

	Three Months Ended September 30					
	2023			2022		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 94,555**	**$ 274,421**	**$ 368,976**	$ 103,523	$ 49,150	$ 152,673
Facilities	**10,918**	**21,773**	**32,691**	8,130	969	9,099
Land, seismic and other	**1,580**	**5,944**	**7,524**	5,497	184	5,681
Exploration and development expenditures	**$ 107,053**	**$ 302,138**	**$ 409,191**	$ 117,150	$ 50,303	$ 167,453
Property acquisitions	**$ 4,277**	**$ —**	**$ 4,277**	$ —	$ —	$ —
Proceeds from dispositions	**$ (226)**	**$ —**	**$ (226)**	$ (25,460)	$ —	$ (25,460)

	Nine Months Ended September 30					
	2023			2022		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 327,026**	**$ 394,850**	**$ 721,876**	$ 247,785	$ 119,454	$ 367,239
Facilities	**39,228**	**20,345**	**59,573**	22,807	2,769	25,576
Land, seismic and other	**21,808**	**10,264**	**32,072**	24,569	524	25,093
Exploration and development expenditures	**$ 388,062**	**$ 425,459**	**$ 813,521**	$ 295,161	$ 122,747	$ 417,908
Property acquisitions	**$ 4,721**	**$ —**	**$ 4,721**	$ 267	$ —	$ 267
Proceeds from dispositions	**$ (511)**	**$ —**	**$ (511)**	$ (25,501)	$ —	$ (25,501)

Exploration and development expenditures were $409.2 million for Q3/2023 and $813.5 million for YTD 2023 compared to $167.5 million for Q3/2022 and $417.9 million for YTD 2022. Exploration and development expenditures for Q3/2023 and YTD 2023 reflect increased development activity in Canada along with expenditures for development activity that occurred on the properties acquired from Ranger after the acquisition closed on June 20, 2023.

In Canada, exploration and development expenditures were $107.1 million in Q3/2023 and $388.1 million in YTD 2023 compared to $117.2 million in Q3/2022 and $295.2 million in YTD 2022. Drilling and completion spending of $94.6 million in Q3/2023 was relatively consistent with $103.5 million Q3/2022 which reflects similar development activity levels on our Canadian properties. YTD 2023 drilling and completion spending of $327.0 million reflects increased light and heavy oil development activity relative to YTD 2022 when we spent $247.8 million. We also invested $39.2 million on facilities and $21.8 million on land, seismic and other expenditures during YTD 2023.

Total U.S. exploration and development expenditures were $302.1 million for Q3/2023 and $425.5 million for YTD 2023 compared to $50.3 million in Q3/2022 and $122.7 million during YTD 2022. Exploration and development activity for Q3/2023 and YTD 2023 reflects expenditures for development activity that occurred on the properties acquired after the Merger closed on June 20, 2023 along with additional activity on our non-operated properties in the Eagle Ford.

Our exploration and development expenditures for YTD 2023 are consistent with expectations and we now expect full year expenditures of approximately $1,035 million for 2023 which reflects expenditures on our operated Eagle Ford properties acquired in the Merger.

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain a strong balance sheet that provides financial flexibility to execute our development programs, provide returns to shareholders and optimize our portfolio through strategic acquisitions. We strive to actively manage our capital structure in response to changes in economic conditions. At September 30, 2023, our capital structure was comprised of shareholders' capital, long-term notes, trade receivables and prepaids, trade and other payables, dividends payable, cash and the credit facilities.

In order to manage our capital structure and liquidity, we may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

Management of debt levels is a priority for us in order to sustain operations and support our business strategy. At September 30, 2023, net debt(1) was $2.8 billion compared to $987.4 million at December 31, 2022. The increase in net debt is primarily due to $732.8 million of cash consideration paid and the assumption of $1.1 billion of net debt assumed in conjunction with the Merger. The cash portion of the transaction was funded with Baytex's expanded US$1.1 billion credit facility, a US$150 million two-year term loan facility which was repaid in August 2023 along with the net 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 released from escrow at completion of the Merger.

In June 2023, we renewed our normal course issuer bid ("NCIB") and began repurchasing our common shares in July 2023 as part of our shareholder return framework. As of October 31, 2023, we have repurchased 28.1 million common shares at an average price of $5.51 per share for total consideration of $155.0 million. On October 2, 2023, we paid a quarterly cash dividend of CDN$0.0225 per share and, on November 2, 2023, the Board of Directors declared a quarterly cash dividend of CDN$0.0225 per share to be paid on January 2, 2024 for shareholders of record on December 15, 2023. These dividends are designated as “eligible dividends” for Canadian income tax purposes. For U.S. income tax purposes, Baytex’s dividends are considered “qualified dividends.”

Credit Facilities

At September 30, 2023, the principal amount of borrowings outstanding under our credit facilities was $1.0 billion. Our credit facilities include US$1.1 billion of revolving credit facilities (the "Credit Facilities").

On June 20, 2023, we amended our Credit Facilities to facilitate the cash consideration paid in conjunction with the Merger and to assume Ranger's net debt. The Credit Facilities were increased to US$1.1 billion and mature on April 1, 2026. The Credit Facilities are secured and are comprised of a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex and a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc.

The Credit Facilities 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 7.8% for Q3/2023 and 7.3% for YTD 2023 compared to 4.1% and 3.1% for Q3/2022 and YTD 2022, respectively. The interest rate on our Credit Facilities has increased due to an increase in the margins applicable to our Credit Facilities along with higher government benchmark rates in 2023 relative to 2022.

As at September 30, 2023, Baytex had $17.1 million of outstanding letters of credit, $15.7 million of which is 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.sedarplus.com.

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

Financial Covenants

The following table summarizes the financial covenants applicable to the credit facilities and our compliance therewith at September 30, 2023.

Covenant Description	Position as at September 30, 2023	Covenant
Senior Secured Debt [1] to Bank EBITDA [2] (Maximum Ratio)	**0.5:1.0**	3.5:1.0
Interest Coverage [3] (Minimum Ratio)	**12.3:1.0**	3.5:1.0
Total Debt [4] to Bank EBITDA [2] (Maximum Ratio)	**1.2:1.0**	4:0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit agreement. At September 30, 2023 our Senior Secured Debt was $1,046.8 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 September 30, 2023 was $2.2 billion.

(3) "Interest coverage" is calculated in accordance with the credit facility agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expenses for the twelve months ended September 30, 2023 were $176.3 million.

(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade and other payables, asset retirement obligations, leases, deferred income tax liabilities, and financial derivative liabilities. At September 30, 2023 our Total Debt was $2.7 billion.

Long-Term Notes

We have two issuances of long-term notes outstanding with a total principal amount of $1.6 billion at September 30, 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 and will be redeemable at par from April 1, 2026 to maturity. At September 30, 2023 there was US$409.8 million aggregate principal amount of the 8.75% Senior Notes outstanding.

On April 27, 2023, we issued US$800 million aggregate principal amount of senior unsecured notes due April 30, 2030 bearing interest at a rate of 8.50% per annum semi-annually (the "8.50% Senior Notes"). The 8.50% Senior Notes were issued at 98.709% of par and are redeemable at our option, in whole or in part, at specified redemption prices after April 30, 2026 and will be redeemable at par from April 30, 2028 to maturity. Net proceeds of $1.0 billion reflects $13.7 million for the original issue discount and Baytex also incurred transaction costs of $18.5 million in conjunction with the issuance.

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 nine months ended September 30, 2023, we issued 311.4 million common shares on closing of the Merger with Ranger in addition to 5.9 million common shares to settle awards outstanding in conjunction with the Merger. As at September 30, 2023, we had 845.4 million common shares issued and outstanding and no preferred shares issued and outstanding.

During Q3/2023 we repurchased 16.8 million common shares for $89.3 million at an average price of $5.30 per share under our NCIB. Through November 1, 2023 we have repurchased 10.4 million common shares for $60.5 million.

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 September 30, 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	**$ 685,392**	$ 677,856	$ 7,536	$ —	$ —
Financial derivatives	**12,793**	12,793	—	—	—
Credit facilities – principal	**1,046,756**	—	1,046,756	—	—
Long-term notes – principal	**1,637,640**	—	—	554,719	1,082,921
Interest on long-term notes [(1)]	**776,339**	140,586	281,172	208,565	146,016
Lease obligations – principal	**41,468**	19,633	8,428	6,986	6,421
Processing agreements	**5,531**	679	993	582	3,277
Transportation agreements	**234,291**	54,706	100,324	60,075	19,186
Total	**$ 4,440,210**	$ 906,253	$ 1,445,209	$ 830,927	$ 1,257,821

(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)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Petroleum and natural gas sales	**1,163,010**	598,760	555,336	648,986	712,065	854,169	673,825	552,403
Net income (loss)	**127,430**	213,603	51,441	352,807	264,968	180,972	56,858	563,239
Per common share – basic	**0.15**	0.37	0.09	0.65	0.48	0.32	0.10	1.00
Per common share – diluted	**0.15**	0.36	0.09	0.64	0.47	0.32	0.10	0.98
Adjusted funds flow (1)	**581,623**	273,590	236,989	255,552	284,288	345,704	279,607	214,766
Per common share – basic	**0.68**	0.47	0.43	0.47	0.51	0.61	0.49	0.38
Per common share – diluted	**0.68**	0.47	0.43	0.46	0.51	0.60	0.49	0.37
Free cash flow (2)	**158,440**	96,313	(1,918)	143,324	111,568	245,316	121,318	137,133
Per common share – basic	**0.19**	0.17	—	0.26	0.20	0.43	0.21	0.24
Per common share – diluted	**0.18**	0.16	—	0.26	0.20	0.43	0.21	0.24
Cash flows from operating activities	**444,033**	192,308	184,938	303,441	310,423	360,034	198,974	240,567
Per common share – basic	**0.52**	0.33	0.34	0.56	0.56	0.63	0.35	0.43
Per common share – diluted	**0.52**	0.33	0.34	0.55	0.56	0.63	0.35	0.42
Dividends declared	**19,138**	—	—	—	—	—	—	—
Per common share – basic	**0.02**	—	—	—	—	—	—	—
Per common share – diluted	**0.02**	—	—	—	—	—	—	—
Exploration and development	**409,191**	170,704	233,626	103,634	167,453	96,633	153,822	73,995
Canada	**107,053**	96,403	184,606	85,641	117,150	51,881	126,130	59,821
U.S.	**302,138**	74,301	49,020	17,993	50,303	44,752	27,692	14,174
Property acquisitions	**4,277**	(62)	506	1,085	—	208	59	1,443
Proceeds from dispositions	**(226)**	(50)	(235)	(148)	(25,460)	(14)	(27)	(6,857)
Net debt (1)	**2,824,348**	2,814,844	995,170	987,446	1,113,559	1,123,297	1,275,680	1,409,717
Total assets (3)	**8,946,181**	8,617,444	5,180,059	5,103,769	4,923,617	4,870,432	4,917,811	4,834,643
Common shares outstanding	**845,360**	862,192	545,553	544,930	547,615	560,139	569,214	564,213
Daily production								
Total production (boe/d)	**150,600**	89,761	86,760	86,864	83,194	83,090	80,867	80,789
Canada (boe/d)	**63,289**	55,874	60,651	56,946	55,803	54,919	53,385	50,362
U.S. (boe/d)	**87,311**	33,887	26,109	29,918	27,391	28,170	27,482	30,428
Benchmark prices								
WTI oil (US$/bbl)	**82.26**	73.78	76.13	82.64	91.56	108.41	94.29	77.19
WCS heavy oil ($/bbl)	**93.02**	78.85	69.44	77.37	93.62	122.05	100.99	78.82
Edmonton par oil ($/bbl)	**107.93**	95.13	99.04	109.57	116.79	137.79	115.66	93.29
CAD/USD avg exchange rate	**1.3410**	1.3431	1.3520	1.3577	1.3059	1.2766	1.2661	1.2600
AECO natural gas ($/mcf)	**2.39**	2.35	4.34	5.58	5.81	6.27	4.59	4.94
NYMEX natural gas (US$/mmbtu)	**2.55**	2.10	3.42	6.26	8.20	7.17	4.95	5.83
Total sales, net of blending and other expense ($/boe) (2)	**80.34**	66.82	63.48	74.93	87.68	105.44	86.89	70.42
Royalties ($/boe) (4)	**(17.33)**	(13.21)	(11.94)	(15.23)	(19.21)	(22.69)	(16.86)	(13.47)
Operating expense ($/boe) (4)	**(12.57)**	(14.62)	(14.40)	(13.06)	(14.39)	(14.21)	(13.85)	(12.83)
Transportation expense ($/boe) (4)	**(2.02)**	(1.78)	(2.18)	(1.85)	(1.67)	(1.56)	(1.27)	(1.10)
Operating netback ($/boe) (2)	**48.42**	37.21	34.96	44.79	52.41	66.98	54.91	43.02
Financial derivatives (loss) gain ($/boe) (4)	**0.15**	2.00	0.69	(6.21)	(9.98)	(16.41)	(11.59)	(9.49)
Operating netback after financial derivatives ($/boe) (2)	**48.57**	39.21	35.65	38.58	42.43	50.57	43.32	33.53

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this MD&A for further information.
(3) Previously disclosed amounts have been revised to conform with current period presentation.
(4) Calculated as royalties expense, operating expense, transportation expense or financial derivatives gain or loss divided by barrels of oil equivalent production volume for the 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 of 150,600 boe/d for Q3/2023 has steadily increased from 80,789 boe/d in Q4/2021 which reflects strong well performance and increased development activity as commodity prices have improved along with the production contribution from the Merger with Ranger which closed on June 20, 2023.

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 increased our realized sales price to $105.44/boe for Q2/2022. Our realized price of $80.34/boe for Q3/2023 reflects recent improvements in crude oil prices due to stable demand and reducing inventories along with the production contribution from the properties acquired in the Merger which receive pricing based on U.S. Gulf Coast benchmarks.

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 $581.6 million for Q3/2023 reflects strong price realizations and production results from our development plans in the U.S. and Canada in addition to the Merger.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, acquisitions and dispositions, changes in our free cash flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. The increase in net debt(1) from $1.4 billion at Q4/2021 to $2.8 billion at Q3/2023 is primarily a result of the Merger which closed in Q2/2023 along with $267.2 million of shareholder returns. The change in net debt also reflects free cash flow(2) of $1.0 billion generated over the last eight quarters.

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

ENVIRONMENTAL REGULATIONS

As a result of our involvement in the exploration for and production of oil and natural gas we are subject to various emissions, carbon and other environmental regulations. Refer to the AIF for the year ended December 31, 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

In June 2023, the International Sustainability Standards Board ("ISSB") issued IFRS S1 *General Requirements for Disclosure of Sustainability-related Financial Information* and IFRS S2 *Climate-related Disclosures* which are effective for annual reporting periods beginning on or after January 1, 2024. These standards provide for transition relief in IFRS S1 that allow reporting entity to report on only climate-related risks and opportunities in the first year of reporting under the sustainability standards.

The Canadian Securities Administrators ("CSA") are responsible for determining the reporting requirements for public companies in Canada and are responsible for decisions related to the adoption of the sustainability disclosure standard, including the effective annual reporting dates. The CSA issued proposed National Instrument *NI-51-107 – Disclosure of Climate-related Matters* in October 2021. The CSA intends to consider the ISSB standards in addition to development in United States reporting requirements in its decision relating to development of climate-related disclosure requirements for Canadian reporting issuers. The CSA will involve the Canadian Sustainability Standards Board ("CSSB") for a combined review of the suitability of the adopting the ISSB standards in Canada. There is no requirement for public companies in Canada to adopt the ISSB standards until the CSA and CSSB have issued a decision on reporting requirements in Canada. While we are actively reviewing the ISSB standards we have not yet determined the impact on future financial statements nor have we quantified the costs to comply with such standards.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at September 30, 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 nine months ended September 30, 2023 except for the critical accounting estimates related to the business combination with Ranger. 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" and "net debt" which are capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

Non-GAAP Financial Measures

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

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

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

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2023**	2022	**2023**	2022
Petroleum and natural gas sales	**$ 1,163,010**	$ 712,065	**$ 2,317,106**	$ 2,240,059
Light oil and condensate [1]	**(756,779)**	(363,968)	**(1,354,053)**	(1,140,534)
NGL [1]	**(46,972)**	(30,556)	**(88,969)**	(93,230)
Natural gas sales [1]	**(35,987)**	(49,583)	**(82,278)**	(147,798)
Heavy oil sales	**$ 323,272**	$ 267,958	**$ 791,806**	$ 858,497
Blending and other expense [2]	**(49,830)**	(40,945)	**(162,506)**	(139,280)
Heavy oil, net of blending and other expense	**$ 273,442**	$ 227,013	**$ 629,300**	$ 719,217

(1) Component of petroleum and natural gas sales. See Note 13 – Petroleum and Natural Gas Sales in the consolidated financial statements for the three and nine months ended September 30, 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 September 30		Nine Months Ended September 30	
($ thousands)	**2023**	2022	**2023**	2022
Petroleum and natural gas sales	**$ 1,163,010**	$ 712,065	**$ 2,317,106**	$ 2,240,059
Blending and other expense	**(49,830)**	(40,945)	**(162,506)**	(139,280)
Total sales, net of blending and other expense	**1,113,180**	671,120	**2,154,600**	2,100,779
Royalties	**(240,049)**	(146,994)	**(441,222)**	(441,273)
Operating expense	**(174,119)**	(110,139)	**(405,965)**	(318,331)
Transportation expense	**(27,983)**	(12,771)	**(59,562)**	(33,744)
Operating netback	**671,029**	401,216	**1,247,851**	1,307,431
Realized financial derivatives gain (loss) [1]	**2,055**	(76,408)	**23,835**	(284,816)
Operating netback after realized financial derivatives	**$ 673,084**	$ 324,808	**$ 1,271,686**	$ 1,022,615

(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 and nine months ended September 30, 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, transaction costs, and cash premiums on derivatives.

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

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2023**	2022	**2023**	2022
Cash flows from operating activities	**$ 444,033**	$ 310,423	**$ 821,279**	$ 869,431
Change in non-cash working capital	**126,075**	(30,734)	**205,924**	$ 29,560
Additions to exploration and evaluation assets	**(40)**	—	**(1,271)**	(5,897)
Additions to oil and gas properties	**(409,151)**	(167,453)	**(812,250)**	(412,011)
Payments on lease obligations	**(4,740)**	(668)	**(7,076)**	(2,881)
Transaction costs	**2,263**	—	**43,966**	—
Cash premiums on derivatives	**—**	—	**2,263**	—
Free cash flow	**$ 158,440**	$ 111,568	**$ 252,835**	$ 478,202

Non-GAAP Financial Ratios

Heavy oil, net of blending and other expense per bbl

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

Total sales, net of blending and other expense per boe

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

Average royalty rate

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

Operating netback per boe

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

Capital Management Measures

Net debt

We use net debt to monitor our current financial position and to evaluate existing sources of liquidity. We define net debt to be the sum of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade and other payables, dividends payable, cash, and trade receivables and prepaids. We also use net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations.

The following table summarizes our calculation of net debt.

($ thousands)	September 30, 2023	December 31, 2022
Credit facilities	$ 1,028,867	$ 383,031
Unamortized debt issuance costs - Credit facilities [1]	17,889	2,363
Long-term notes	1,600,397	547,598
Unamortized debt issuance costs - Long-term notes [1]	37,243	6,999
Trade and other payables	685,392	281,404
Dividends payable	19,138	—
Cash	(23,899)	(5,464)
Trade receivables and prepaids	(540,679)	(228,485)
Net debt	$ 2,824,348	$ 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 and nine months ended September 30, 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, transaction costs and cash premiums on derivatives.

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

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	2023	2022	2023	2022
Cash flow from operating activities	$ 444,033	$ 310,423	$ 821,279	$ 869,431
Change in non-cash working capital	126,075	(30,734)	205,924	29,560
Asset retirement obligations settled	9,252	4,599	18,770	10,608
Transaction costs	2,263	—	43,966	—
Cash premiums on derivatives	—	—	2,263	—
Adjusted funds flow	$ 581,623	$ 284,288	$ 1,092,202	$ 909,599

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 September 30, 2023, except for the matter described below.

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

During the three months ended September 30, 2023, the assets previously held by Ranger contributed revenues of $452.7 million (representing 39% of total revenues) and net income before tax of $106.1 million (representing 60% of total net income before tax). At September 30, 2023, current assets of $229.5 million, non-current assets of $3.4 billion, current liabilities of $356.6 million and non-current liabilities of $83.9 million were associated with the acquired entity.

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: our planned allocation of free cash flow to debt repayment, dividends and share buybacks; our 2023 guidance with respect to exploration and development expenditures, average daily production, royalty rate and operating, transportation, general and administrative and interest expenses, leasing expenditures and asset retirement obligations; the existence, operation and strategy of our risk management program; that we expect to cash settle share awards; the manner in which we fund our planned capital expenditures and monitor and manage our capital resources and liquidity; and that we may issue debt or equity securities, sell assets or adjust capital spending.

These forward-looking statements are based on certain key assumptions regarding, among other things: 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; the future impact of wildfires on our production; that our core assets have more than 10 years development inventory at the current pace of development; 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, including operating and transportation costs; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our hedging program; 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: risks relating to any unforeseen liabilities of Baytex; that Baytex fails to meet its guidance; the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); risks related to ongoing wildfires; 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, including transportation costs; 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.

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) will be subject to the discretion of the Board of Directors of Baytex and may depend on a variety of factors, including, without limitation, Baytex's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on Baytex under applicable corporate law. Further, the actual amount, the declaration date, the record date and the payment date of any dividend are subject to the discretion of the Board of Directors of Baytex.

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

	Notes	As at September 30, 2023	As at December 31, 2022
ASSETS			
Current assets			
Cash		$ **23,899**	$ 5,464
Trade receivables and prepaids		**540,679**	228,485
Financial derivatives	17	**6,695**	10,105
		571,273	244,054
Non-current assets			
Exploration and evaluation assets	5	**163,939**	168,684
Oil and gas properties	6	**7,939,993**	4,620,766
Other plant and equipment		**7,088**	6,568
Lease assets		**34,554**	6,453
Deferred income tax asset	14	**229,334**	57,244
		$ **8,946,181**	$ 5,103,769
LIABILITIES			
Current liabilities			
Trade and other payables		$ **677,856**	$ 272,195
Dividends payable		**19,138**	—
Financial derivatives	17	**12,793**	—
Lease obligations		**18,033**	3,521
Asset retirement obligations	9	**14,730**	12,813
		742,550	288,529
Non-current liabilities			
Trade and other payables		**7,536**	9,209
Credit facilities	7	**1,028,867**	383,031
Long-term notes	8	**1,600,397**	547,598
Lease obligations		**16,912**	3,017
Asset retirement obligations	9	**599,536**	576,110
Deferred income tax liability	14	**218,165**	265,858
		4,213,963	2,073,352
SHAREHOLDERS' EQUITY			
Shareholders' capital	10	**6,717,633**	5,499,664
Contributed surplus		**135,399**	89,879
Accumulated other comprehensive income		**821,171**	756,195
Deficit		**(2,941,985)**	(3,315,321)
		4,732,218	3,030,417
		$ **8,946,181**	$ 5,103,769

Subsequent events (note 10 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 September 30		Nine Months Ended September 30	
	Notes	**2023**	2022	**2023**	2022
Revenue, net of royalties					
Petroleum and natural gas sales	13	**$ 1,163,010**	$ 712,065	**$ 2,317,106**	$ 2,240,059
Royalties		**(240,049)**	(146,994)	**(441,222)**	(441,273)
		922,961	565,071	**1,875,884**	1,798,786
Expenses					
Operating		**174,119**	110,139	**405,965**	318,331
Transportation		**27,983**	12,771	**59,562**	33,744
Blending and other		**49,830**	40,945	**162,506**	139,280
General and administrative		**20,536**	12,003	**47,510**	35,325
Transaction costs	3	**2,263**	—	**43,966**	—
Exploration and evaluation	5	**409**	6,566	**941**	17,346
Depletion and depreciation		**319,731**	144,177	**661,874**	427,254
Share-based compensation	11	**14,699**	3,072	**41,440**	9,959
Financing and interest	15	**68,065**	25,753	**126,287**	77,074
Financial derivatives loss (gain)	17	**28,641**	(114,063)	**17,054**	191,838
Foreign exchange loss	16	**42,682**	38,905	**30,680**	52,269
Gain on dispositions		**(875)**	(4,566)	**(539)**	(5,007)
Other (income) expense		**(1,367)**	5,223	**(2,284)**	4,759
		746,716	280,925	**1,594,962**	1,302,172
Net income before income taxes		**176,245**	284,146	**280,922**	496,614
Income tax expense (recovery)	14				
Current income tax expense		**808**	703	**3,278**	2,753
Deferred income tax expense (recovery)		**48,007**	18,475	**(114,830)**	(8,937)
		48,815	19,178	**(111,552)**	(6,184)
Net income		**$ 127,430**	$ 264,968	**$ 392,474**	$ 502,798
Other comprehensive income					
Foreign currency translation adjustment		**111,981**	117,023	**64,976**	147,861
Comprehensive income		**$ 239,411**	$ 381,991	**$ 457,450**	$ 650,659
Net income per common share	12				
Basic		**$ 0.15**	$ 0.48	**$ 0.59**	$ 0.89
Diluted		**$ 0.15**	$ 0.47	**$ 0.59**	$ 0.89
Weighted average common shares (000's)	12				
Basic		**855,300**	553,409	**662,379**	561,931
Diluted		**860,572**	559,174	**666,194**	567,662

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 (loss)	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		8,501	(8,501)	—	—	**—**
Share-based compensation		—	2,715	—	—	**2,715**
Repurchase of common shares for cancellation		(217,263)	76,009	—	—	**(141,254)**
Comprehensive income		—	—	147,861	502,798	**650,659**
Balance at September 30, 2022		$ 5,527,831	$ 83,782	$ 779,964	$ (3,668,128)	**$ 2,723,449**
Balance at December 31, 2022		$ 5,499,664	$ 89,879	$ 756,195	$ (3,315,321)	**$ 3,030,417**
Issued on corporate acquisition	3	1,326,435	21,316	—	—	**1,347,751**
Vesting of share awards	10	26,229	(37,462)	—	—	**(11,233)**
Share-based compensation	11	—	16,237	—	—	**16,237**
Repurchase of common shares for cancellation	10	(134,695)	45,429	—	—	**(89,266)**
Dividends declared	10	—	—	—	(19,138)	**(19,138)**
Comprehensive income		—	—	64,976	392,474	**457,450**
Balance at September 30, 2023		$ 6,717,633	$ 135,399	$ 821,171	$ (2,941,985)	**$ 4,732,218**

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 September 30		Nine Months Ended September 30	
	Notes	**2023**	2022	**2023**	2022
CASH PROVIDED BY (USED IN):					
Operating activities					
Net income		**$ 127,430**	$ 264,968	**$ 392,474**	$ 502,798
Adjustments for:					
Non-cash share-based compensation	11	**—**	637	**16,237**	2,715
Unrealized foreign exchange loss	16	**42,392**	39,799	**29,299**	52,750
Exploration and evaluation	5	**409**	6,566	**941**	17,346
Depletion and depreciation		**319,731**	144,177	**661,874**	427,254
Non-cash financing and accretion	15	**11,570**	5,979	**23,162**	16,399
Non-cash other income	9	**—**	(1,276)	**(1,271)**	(2,741)
Unrealized financial derivatives loss (gain)	17	**30,696**	(190,471)	**40,889**	(92,978)
Cash premiums on derivatives		**—**	—	**(2,263)**	—
Gain on dispositions		**(875)**	(4,566)	**(539)**	(5,007)
Deferred income tax expense (recovery)	14	**48,007**	18,475	**(114,830)**	(8,937)
Asset retirement obligations settled	9	**(9,252)**	(4,599)	**(18,770)**	(10,608)
Change in non-cash working capital		**(126,075)**	30,734	**(205,924)**	(29,560)
		444,033	310,423	**821,279**	869,431
Financing activities					
Increase (decrease) in credit facilities		**46,602**	(58,266)	**648,581**	(73,617)
Decrease in acquired credit facilities	3	**—**	—	**(373,608)**	—
Debt issuance costs		**(198)**	(305)	**(40,123)**	(2,137)
Payments on lease obligations		**(4,740)**	(668)	**(7,076)**	(2,881)
Net proceeds from issuance of long-term notes	8	**—**	—	**1,046,197**	—
Redemption of long-term notes	8	**—**	(35,599)	**—**	(288,429)
Redemption of acquired long-term notes	3	**—**	—	**(569,256)**	—
Repurchase of common shares	10	**(89,266)**	(78,790)	**(89,266)**	(141,254)
Dividends declared		**(19,138)**	—	**(19,138)**	—
Change in non-cash working capital		**(25,734)**	—	**(25,734)**	—
		(92,474)	(173,628)	**570,577**	(508,318)
Investing activities					
Additions to exploration and evaluation assets	5	**(40)**	—	**(1,271)**	(5,897)
Additions to oil and gas properties	6	**(409,151)**	(167,453)	**(812,250)**	(412,011)
Additions to other plant and equipment		**(1,279)**	(148)	**(2,300)**	(782)
Corporate acquisition, net of cash acquired	3	**—**	—	**(662,579)**	—
Property acquisitions		**(4,277)**	—	**(4,721)**	(267)
Proceeds from dispositions		**226**	25,460	**511**	25,501
Change in non-cash working capital		**67,224**	9,756	**109,189**	36,753
		(347,297)	(132,385)	**(1,373,421)**	(356,703)
Change in cash		**4,262**	4,410	**18,435**	4,410
Cash, beginning of period		**19,637**	—	**5,464**	—
Cash, end of period		**$ 23,899**	$ 4,410	**$ 23,899**	$ 4,410
Supplementary information					
Interest paid		**$ 45,941**	$ 35,587	**$ 83,945**	$ 77,116
Income taxes paid		**$ —**	$ 1,906	**$ 3,603**	$ 2,169

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 ("2022 annual consolidated financial statements").

The consolidated financial statements were approved by the Board of Directors of Baytex on November 2, 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 2022 annual consolidated financial statements are available through its filings on SEDAR+ at www.sedarplus.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. There have been no changes in our key areas of judgement or estimation uncertainty for the nine months ended September 30, 2023 except for the judgements and estimates related to Business Combinations as discussed below.

Business Combinations

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

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 two IFRS Sustainability Disclosure Standards 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, with the addition of Business Combinations, and significant estimates used in these consolidated financial statements are consistent with those used in the preparation of the 2022 annual consolidated financial statements.

3. BUSINESS COMBINATION

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

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

The fair value of oil and gas properties acquired is based on estimates of proved and probable oil and gas reserves and the present value of the associated cash flows. Factors that impact these cash flows include production volumes, royalty obligations, operating costs, capital costs, tax rates, forecasted commodity prices, along with inflation and discount rates. These calculations require the use of estimates and assumptions including cash flows associated with proved plus probable oil and gas reserves, the discount rate used to present value future cash flows, and assumptions regarding the timing and amount of capital expenditures and future abandonment and reclamation obligations. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets. The fair value of oil and gas properties were determined using a discount rate of 12.5%.

Asset retirement obligations were determined using internal estimates of the timing and estimated costs associated with the abandonment and reclamation of the wells and facilities acquired using a credit-adjusted discount rate of 9%.

The total consideration paid and estimates of the fair value of the assets and liabilities as at the date of the acquisition are set forth in the table below. The preliminary purchase price allocation is based on Management's best estimate of the assets acquired and liabilities assumed. Adjustments to these initial estimates may be required upon finalizing the value of net assets acquired.

		USD		CAD (1)
Consideration				
Cash	$	553,150	$	732,840
Common shares issued		1,001,196		1,326,435
Share based compensation (2)		20,107		26,638
Total consideration	**$**	**1,574,453**	**$**	**2,085,913**
Fair value of net assets acquired				
Oil and gas properties	$	2,325,996	$	3,081,596
Working capital deficiency excluding bank debt and financial derivatives (3)		(108,147)		(143,278)
Financial derivatives		17,030		22,562
Lease assets		15,708		20,811
Lease obligations		(15,708)		(20,811)
Credit facilities		(282,000)		(373,608)
Long-term notes		(429,676)		(569,256)
Asset retirement obligations		(23,632)		(31,310)
Deferred income tax asset		74,882		99,207
Net assets acquired	**$**	**1,574,453**	**$**	**2,085,913**

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

(2) Follow closing of the transaction, holders of awards outstanding under Ranger's share based compensation plans are entitled to Baytex common shares rather than Ranger common shares with adjustment to the quantity outstanding based on the exchange ratio for Ranger shares. The fair value of share awards allocated to consideration was based on the service period that had occurred prior to the acquisition date while the remaining fair value of the share awards assumed by Baytex will be recognized over the remaining future service periods (note 11). Included in this balance is $21.3 million (US$16.1 million) of awards that were vested in full at close of the Ranger acquisition and $5.3 million (US$4.0 million) of cash-based awards included in trade and other payables.

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

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

These consolidated financial statements include the results of operations of Ranger for the period following closing of the transaction on June 20, 2023. For the nine months ended September 30, 2023, the acquisition contributed revenues and net income before tax of $501.8 million and $107.8 million, respectively. Had the acquisition occurred on January 1, 2023, revenues and net income before income taxes would have increased by $1.3 billion and $325.1 million, respectively, for the nine months ended September 30, 2023. This pro-forma information is not necessarily indicative of the results of operations that would have resulted had the acquisition been reflected on the dates indicated, or that may be obtained in the future.

During the nine months ended September 30, 2023, Baytex incurred $44.0 million of transaction costs, including consulting, financial advisory, legal and filing fees related to the acquisition of Ranger.

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 September 30	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 515,218**	$ 473,708	**$ 647,792**	$ 238,357	**$ —**	$ —	**$1,163,010**	$ 712,065
Royalties	**(64,238)**	(75,901)	**(175,811)**	(71,093)	**—**	—	**(240,049)**	(146,994)
	450,980	397,807	**471,981**	167,264	**—**	—	**922,961**	565,071
Expenses								
Operating	**93,065**	83,141	**81,054**	26,998	**—**	—	**174,119**	110,139
Transportation	**16,075**	12,771	**11,908**	—	**—**	—	**27,983**	12,771
Blending and other	**49,830**	40,945	**—**	—	**—**	—	**49,830**	40,945
General and administrative	**—**	—	**—**	—	**20,536**	12,003	**20,536**	12,003
Transaction costs	**—**	—	**—**	—	**2,263**	—	**2,263**	—
Exploration and evaluation	**409**	6,566	**—**	—	**—**	—	**409**	6,566
Depletion and depreciation	**124,214**	102,353	**193,334**	40,298	**2,183**	1,526	**319,731**	144,177
Share-based compensation	**—**	—	**—**	—	**14,699**	3,072	**14,699**	3,072
Financing and interest	**—**	—	**—**	—	**68,065**	25,753	**68,065**	25,753
Financial derivatives loss (gain)	**—**	—	**—**	—	**28,641**	(114,063)	**28,641**	(114,063)
Foreign exchange loss	**—**	—	**—**	—	**42,682**	38,905	**42,682**	38,905
Gain on dispositions	**(875)**	(4,566)	**—**	—	**—**	—	**(875)**	(4,566)
Other (income) expense	**—**	(1,276)	**—**	—	**(1,367)**	6,499	**(1,367)**	5,223
	282,718	239,934	**286,296**	67,296	**177,702**	(26,305)	**746,716**	280,925
Net income (loss) before income taxes	**168,262**	157,873	**185,685**	99,968	**(177,702)**	26,305	**176,245**	284,146
Income tax (recovery) expense								
Current income tax expense							**808**	703
Deferred income tax (recovery) expense							**48,007**	18,475
							48,815	19,178
Net income (loss)	**$ 168,262**	$ 157,873	**$ 185,685**	$ 99,968	**$ (177,702)**	$ 26,305	**$ 127,430**	$ 264,968
Additions to exploration and evaluation assets	**40**	—	**—**	—	**—**	—	**40**	—
Additions to oil and gas properties	**107,013**	117,150	**302,138**	50,303	**—**	—	**409,151**	167,453
Corporate acquisition, net of cash acquired	**—**	—	**—**	—	**—**	—	**—**	—
Property acquisitions	**4,277**	—	**—**	—	**—**	—	**4,277**	—
Proceeds from dispositions	**(226)**	(25,460)	**—**	—	**—**	—	**(226)**	(25,460)

	Canada		U.S.		Corporate		Consolidated	
Nine Months Ended September 30	**2023**	2022	**2023**	2022	**2023**	2022	**2023**	2022
Revenue, net of royalties								
Petroleum and natural gas sales	**$1,291,131**	$1,508,609	**$1,025,975**	$ 731,450	**$ —**	$ —	**$2,317,106**	$2,240,059
Royalties	**(155,402)**	(224,710)	**(285,820)**	(216,563)	**—**	—	**(441,222)**	(441,273)
	1,135,729	1,283,899	**740,155**	514,887	**—**	—	**1,875,884**	1,798,786
Expenses								
Operating	**275,599**	244,152	**130,366**	74,179	**—**	—	**405,965**	318,331
Transportation	**46,320**	33,744	**13,242**	—	**—**	—	**59,562**	33,744
Blending and other	**162,506**	139,280	**—**	—	**—**	—	**162,506**	139,280
General and administrative	**—**	—	**—**	—	**47,510**	35,325	**47,510**	35,325
Transaction costs	**—**	—	**—**	—	**43,966**	—	**43,966**	—
Exploration and evaluation	**941**	17,346	**—**	—	**—**	—	**941**	17,346
Depletion and depreciation	**355,947**	304,147	**300,509**	118,759	**5,418**	4,348	**661,874**	427,254
Share-based compensation	**—**	—	**—**	—	**41,440**	9,959	**41,440**	9,959
Financing and interest	**—**	—	**—**	—	**126,287**	77,074	**126,287**	77,074
Financial derivatives loss	**—**	—	**—**	—	**17,054**	191,838	**17,054**	191,838
Foreign exchange loss	**—**	—	**—**	—	**30,680**	52,269	**30,680**	52,269
Gain on dispositions	**(539)**	(5,007)	**—**	—	**—**	—	**(539)**	(5,007)
Other (income) expense	**(1,271)**	(2,741)	**—**	—	**(1,013)**	7,500	**(2,284)**	4,759
	839,503	730,921	**444,117**	192,938	**311,342**	378,313	**1,594,962**	1,302,172
Net income (loss) before income taxes	**296,226**	552,978	**296,038**	321,949	**(311,342)**	(378,313)	**280,922**	496,614
Income tax (recovery) expense								
Current income tax expense							**3,278**	2,753
Deferred income tax (recovery) expense							**(114,830)**	(8,937)
							(111,552)	(6,184)
Net income (loss)	**$ 296,226**	$ 552,978	**$ 296,038**	$ 321,949	**$ (311,342)**	$ (378,313)	**$ 392,474**	$ 502,798
Additions to exploration and evaluation assets	**1,271**	5,897	**—**	—	**—**	—	**1,271**	5,897
Additions to oil and gas properties	**386,791**	289,264	**425,459**	122,747	**—**	—	**812,250**	412,011
Corporate acquisition, net of cash acquired		—	**662,579**	—	**—**	—	**662,579**	—
Property acquisitions	**4,721**	267	**—**	—	**—**	—	**4,721**	267
Proceeds from dispositions	**(511)**	(25,501)	**—**	—	**—**	—	**(511)**	(25,501)

	September 30, 2023	December 31, 2022
Canadian assets	**$ 2,874,726**	$ 2,779,596
U.S. assets	**6,023,118**	2,301,047
Corporate assets	**48,337**	23,126
Total consolidated assets	**$ 8,946,181**	$ 5,103,769

5. EXPLORATION AND EVALUATION ASSETS

		September 30, 2023		December 31, 2022
Balance, beginning of period	**$**	**168,684**	$	172,824
Capital expenditures		**1,271**		6,359
Property acquisitions		**4,600**		301
Divestitures		**(824)**		(498)
Property swaps		**978**		385
Impairment reversal		**—**		22,503
Exploration and evaluation expense		**(941)**		(30,239)
Transfer to oil and gas properties (note 6)		**(9,820)**		(8,496)
Foreign currency translation		**(9)**		5,545
Balance, end of period	**$**	**163,939**	$	168,684

At September 30, 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)**	**$**	**4,464,371**
Capital expenditures		515,183		—		515,183
Property acquisitions		1,173		—		1,173
Transfers from exploration and evaluation assets (note 5)		8,496		—		8,496
Change in asset retirement obligations (note 9)		(147,020)		—		(147,020)
Divestitures		(265,166)		241,892		(23,274)
Property swaps		—		—		—
Impairment reversal		—		245,241		245,241
Foreign currency translation		296,033		(158,404)		137,629
Depletion		—		(581,033)		(581,033)
Balance, December 31, 2022	**$**	**12,042,216**	**$**	**(7,421,450)**	**$**	**4,620,766**
Capital expenditures		812,250		—		812,250
Corporate acquisition (note 3)		3,081,596		—		3,081,596
Property acquisitions		109		—		109
Transfers from exploration and evaluation assets (note 5)		9,820		—		9,820
Transfers from lease assets		3,736		—		3,736
Change in asset retirement obligations (note 9)		(727)		—		(727)
Divestitures		(1,909)		1,511		(398)
Property swaps		(4,531)		3,756		(775)
Foreign currency translation		73,622		(3,550)		70,072
Depletion		—		(656,456)		(656,456)
Balance, September 30, 2023	**$**	**16,016,182**	**$**	**(8,076,189)**	**$**	**7,939,993**

At September 30, 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

		September 30, 2023		December 31, 2022
Credit facilities - U.S. dollar denominated (1)	**$**	**569,951**	$	30,394
Credit facilities - Canadian dollar denominated		**476,805**		355,000
Credit facilities - principal (2)	**$**	**1,046,756**	$	385,394
Unamortized debt issuance costs		**(17,889)**		(2,363)
Credit facilities	**$**	**1,028,867**	$	383,031

(1) U.S. dollar denominated credit facilities balance was US$421.0 million as at September 30, 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 September 30, 2023 is the result of net draws of $648.9 million, including repayment of the US$150 million term loan, as well as changes in the reported amount of U.S. denominated debt of $12.2 million due to foreign exchange.

At September 30, 2023, Baytex had US$1.1 billion of revolving credit facilities (the "Credit Facilities). On June 20, 2023, in connection with the acquisition of Ranger, Baytex amended its Credit Facilities to increase the committed amount (previously US$850 million in aggregate as of April 1, 2022) and entered into a secured two-year term loan of US$150 million that was repaid and cancelled in August 2023. The maturity date of the Credit Facilities is April 1, 2026.

The Credit Facilities are secured and are comprised of a US$50 million operating loan and a US$750 million syndicated revolving loan for Baytex and a US$45 million operating loan and a US$255 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. The amended Credit Facilities contain an additional financial covenant of a maximum Total Debt to Bank EBITDA ratio of 4.0:1.0 and increased the Interest Coverage minimum ratio to 3.5:1.0 (from 2.0:1.0).

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 7.3% for the nine months ended September 30, 2023 (3.1% for nine months ended September 30, 2022).

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at September 30, 2023.

Covenant Description	**Position as at September 30, 2023**	**Covenant**
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0.5:1.0**	**3.5:1.0**
Interest Coverage (3) (Minimum Ratio)	**12.3:1.0**	**3.5:1.0**
Total Debt (4) to Bank EBITDA (2) (Maximum Ratio)	**1.2:1.0**	**4:0:1.0**

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreement and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit facility agreement. As at September 30, 2023, the Company's Senior Secured Debt totaled $1,046.8 million of principal amounts outstanding.

(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 September 30, 2023 was $2.2 billion.

(3) "Interest coverage" is calculated in accordance with the credit facility agreement and is computed as the ratio of Bank EBITDA to financing and interest expense, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expense for the twelve months ended September 30, 2023 was $176.3 million.

(4) "Total Debt" is calculated in accordance with the credit facility agreement and is defined as all obligations, liabilities, and indebtedness of Baytex excluding trade and other payables, asset retirement obligations, leases, deferred income tax liabilities, and financial derivative liabilities. As at September 30, 2023, the Company's Total Debt totaled $2.7 billion of principal amounts outstanding.

At September 30, 2023, Baytex had $17.1 million of outstanding letters of credit, $15.7 million of which is 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

		September 30, 2023		December 31, 2022
8.75% notes due April 1, 2027 (1)	$	**554,719**	$	554,597
8.50% notes due April 1, 2030 (2)		**1,082,921**		—
Total long-term notes - principal (3)	$	**1,637,640**	$	554,597
Unamortized debt issuance costs		**(37,243)**		(6,999)
Total long-term notes - net of discount and unamortized debt issuance costs	$	**1,600,397**	$	547,598

(1) The U.S. dollar denominated principal outstanding of the 8.75% notes was US$409.8 million as at September 30, 2023 (December 31, 2022 - US$409.8 million).

(2) The U.S. dollar denominated principal outstanding of the 8.50% notes was US$800.0 million as at September 30, 2023 (December 31, 2022 - nil).

(3) The increase in the principal amount of long-term notes outstanding from December 31, 2022 to September 30, 2023 is the result of the issuance of the 8.50% notes for $1.1 billion and includes changes in the reported amount of U.S. denominated debt of $23.2 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 issued US$800 million aggregate principal amount of senior unsecured notes due April 30, 2030 bearing interest at a rate of 8.50% per annum semi-annually (the "8.50% Senior Notes"). The 8.50% Senior Notes were issued at 98.709% of par and are redeemable at our option, in whole or in part, at specified redemption prices after April 30, 2026 and will be redeemable at par from April 30, 2028 to maturity. Net proceeds of $1.0 billion reflects $13.7 million for the original issue discount and Baytex also incurred transaction costs of $18.5 million in conjunction with the issuance.

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

9. ASSET RETIREMENT OBLIGATIONS

		September 30, 2023		December 31, 2022
Balance, beginning of period	$	**588,923**	$	743,683
Liabilities incurred (1)		**17,413**		19,942
Liabilities settled		**(18,770)**		(18,351)
Liabilities assumed from corporate acquisition (note 3)		**31,310**		—
Liabilities acquired from property acquisitions		**11**		950
Liabilities divested		**(1,096)**		(3,464)
Property swaps		**26**		—
Accretion (note 15)		**14,252**		15,683
Government grants (2)		**(1,271)**		(4,009)
Change in estimate (1)		**17,159**		6,124
Changes in discount rates and inflation rates (1)(3)		**(35,299)**		(173,086)
Foreign currency translation		**1,608**		1,451
Balance, end of period	$	**614,266**	$	588,923
Less current portion of asset retirement obligations		**14,730**		12,813
Non-current portion of asset retirement obligations	$	**599,536**	$	576,110

(1) Agrees to total change in asset retirement obligations of $0.7 million per Note 6 - Oil and Gas Properties.

(2) During the nine months ended September 30, 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).

(3) The discount and inflation rates used to calculate the liability for our Canadian operations at September 30, 2023 were 3.8% and 1.8%, respectively (December 31, 2022 - 3.3% and 2.1%). The discount and inflation rates used to calculate the liability for our U.S. operations at September 30, 2023 were 4.7% and 2.3%, respectively (December 31, 2022 - 3.3% and 2.1%). The changes in discount rates also includes the remeasurement of the liability acquired from Ranger from a market rate of interest on the date of acquisition to a risk-free rate at period end.

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 September 30, 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.

In June 2023, the TSX accepted Baytex's notice of intention to renew its Normal Course Issuer Bid ("NCIB"). Under the terms of the NCIB, the Company may purchase for cancellation up to 68.4 million common shares over the 12-month period commencing June 29, 2023. The number of shares authorized for repurchase represents 10% of the Company's public float as at June 21, 2023. On June 21, 2023 Baytex had 856.9 million common shares outstanding. Purchases are made on the open market at prices prevailing at the time of the transaction. During the nine months ended September 30, 2023, Baytex repurchased and cancelled 16.8 million common shares at an average price of $5.30 per share for total consideration of $89.3 million.

As of October 31, 2023, we have repurchased 28.1 million common shares at an average price of $5.51 per share for total consideration of $155.0 million.

In July 2023, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share which was paid on October 2, 2023 for shareholders of record as at September 15, 2023. Subsequent to September 30, 2023, the Company's Board of Directors declared a quarterly cash dividend of $0.0225 per share to be paid on January 2, 2024 for shareholders on record as at December 15, 2023.

	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**
Issued on corporate acquisition (note 3)	311,370		1,326,435
Vesting of share awards	5,892		26,229
Common shares repurchased and cancelled	(16,832)		(134,695)
Balance, September 30, 2023	**845,360**	**$**	**6,717,633**

11. SHARE-BASED COMPENSATION PLAN

For the three and nine months ended September 30, 2023 the Company recorded total share-based compensation expense of $14.7 million and $41.4 million respectively ($3.1 million and $10.0 million for the three and nine months ended September 30, 2022) which are comprised of the expense related to cash-settled awards and the associated equity total return swaps ($2.4 million and $7.3 million for the three and nine months ended September 30, 2022). The nine months ended period is also comprised of $16.2 million of non-cash expense related to awards assumed in the acquisition of Ranger and were settled with Baytex common shares after closing of the business combination.

The Company's closing share price on the Toronto Stock Exchange on September 30, 2023 was $5.99 (September 30, 2022 - $5.85).

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.

On June 20, 2023, Baytex became the successor to Ranger's Share Award Plan. Although no new grants will be made under the Ranger Share Award Plan, awards that were outstanding at June 20, 2023 were converted to restricted awards that will be settled in shares of Baytex or with cash, with the quantity outstanding adjusted based on the exchange ratio for the business combination with Ranger.

The weighted average fair value of share awards granted during the nine months ended September 30, 2023 was $5.44 per restricted and performance award ($5.68 for the nine months ended September 30, 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	41	2,628	2,669
Assumed on corporate acquisition (1)	10,789	—	10,789
Vested	(9,302)	(3,767)	(13,069)
Forfeited	(8)	(234)	(242)
Balance, September 30, 2023	**2,282**	**3,423**	**5,705**

(1) Follow closing of the transaction, holders of awards outstanding under Ranger's share based compensation plans are entitled to Baytex common shares rather than Ranger common shares with adjustment to the quantity outstanding based on the exchange ratio for Ranger shares. The fair value of share awards allocated to consideration was based on the service period that had occurred prior to the acquisition date (note 3) while the remaining fair value of the share awards assumed by Baytex will be recognized over the remaining future service periods.

Incentive Award Plan

Baytex has an Incentive Award Plan whereby the 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 nine months ended September 30, 2023, Baytex granted 2.5 million awards under the Incentive Award plan at a fair value of $5.41 per award (1.4 million awards at $5.68 per award for the nine months ended September 30, 2022). At September 30, 2023 there were 4.5 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 per DSU award on the date at which they cease to be a member of the Board. The awards vest immediately upon being granted and are expensed in full on the grant date. The units are recognized at fair value at each period end and are included in trade and other payables.

During the nine months ended September 30, 2023, Baytex granted 0.3 million awards under the DSU plan at a fair value of $5.15 per award (0.2 million awards at $5.68 per award for the nine months ended September 30, 2022). At September 30, 2023, there were 1.2 million awards outstanding under the DSU plan (1.0 million awards outstanding at December 31, 2022).

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 DSU Plan, at the fair value determined on the grant date.

At September 30, 2023, an asset of $2.7 million associated with the equity return swap was included in trade receivables and prepaids (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 September 30					
	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	**$ 127,430**	**855,300**	**$ 0.15**	$ 264,968	553,409	$ 0.48
Dilutive effect of share awards		**5,272**		—	5,765	—
Net income - diluted	**$ 127,430**	**860,572**	**$ 0.15**	$ 264,968	559,174	$ 0.47

	Nine Months Ended September 30					
	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	**$ 392,474**	**662,379**	**$ 0.59**	$ 502,798	561,931	$ 0.89
Dilutive effect of share awards		**3,815**		—	5,731	—
Net income - diluted	**$ 392,474**	**666,194**	**$ 0.59**	$ 502,798	567,662	$ 0.89

For the three and nine months ended September 30, 2023 and September 30, 2022 no share awards were excluded from the calculation of diluted income per share as all of their effects were 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 September 30					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 173,475**	**$ 583,304**	**$ 756,779**	$ 175,447	$ 188,521	$ 363,968
Heavy oil	**323,272**	**—**	**323,272**	267,958	—	267,958
NGL	**5,945**	**41,027**	**46,972**	7,929	22,627	30,556
Natural gas sales	**12,526**	**23,461**	**35,987**	22,374	27,209	49,583
Total petroleum and natural gas sales	**$ 515,218**	**$ 647,792**	**$ 1,163,010**	$ 473,708	$ 238,357	$ 712,065

	Nine Months Ended September 30					
	2023			2022		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 444,894**	**$ 909,159**	**$ 1,354,053**	$ 548,588	$ 591,946	$ 1,140,534
Heavy oil	**791,806**	**—**	**791,806**	858,497	—	858,497
NGL	**15,777**	**73,192**	**88,969**	23,701	69,529	93,230
Natural gas sales	**38,654**	**43,624**	**82,278**	77,823	69,975	147,798
Total petroleum and natural gas sales	**$ 1,291,131**	**$ 1,025,975**	**$ 2,317,106**	$ 1,508,609	$ 731,450	$ 2,240,059

Included in accounts receivable at September 30, 2023 is $382.0 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:

	Nine Months Ended September 30	
	2023	2022
Net income (loss) before income taxes	**$ 280,922**	$ 496,614
Expected income taxes at the statutory rate of 24.64% (2022 –24.80%) (1)	**69,219**	123,160
Change in income taxes resulting from:		
Effect of foreign exchange	**2,817**	5,917
Effect of change in income tax rates	**(427)**	—
Effect of rate adjustments for foreign jurisdictions	**(7,230)**	(21,237)
Effect of change in deferred tax benefit not recognized (2)	**3,213**	(72,297)
Effect of internal debt restructuring (3)	**(186,319)**	(44,793)
Adjustments, assessments and other	**7,175**	3,066
Income tax expense (recovery)	**$ (111,552)**	$ (6,184)

(1) The expected income tax rate decreased due to changes in the provincial apportionment of Canadian income

(2) A deferred income tax asset of $17.5 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.

(3) A deferred income tax asset has been recognized immediately after the closing of the Ranger acquisition due to effects of the transaction structuring.

As disclosed in the 2022 annual financial statements, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the "CRA") in June 2016 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. In July 2023, Baytex received a letter from the Appeals Division of the CRA proposing to confirm the reassessments. Baytex submitted a response to this proposal in October 2023.

Baytex has received advice from its tax advisors that it should be entitled to use the non-capital loss deductions and remains confident that the original tax filings are correct. As such, Baytex has not recognized any provision in its unaudited interim consolidated financial statements with respect to the reassessments. In the event that Baytex is unsuccessful, Baytex would be required to remit taxes plus interest.

15. FINANCING AND INTEREST

	Three Months Ended September 30		Nine Months Ended September 30	
	2023	2022	**2023**	2022
Interest on Credit Facilities	**$ 21,671**	$ 5,788	**$ 35,422**	$ 12,897
Interest on long-term notes	**34,664**	13,935	**67,323**	47,635
Interest on lease obligations	**160**	51	**380**	143
Cash Interest	**$ 56,495**	$ 19,774	**$ 103,125**	$ 60,675
Amortization of debt issue costs	**6,539**	1,242	**8,910**	4,671
Accretion on asset retirement obligations (note 9)	**5,031**	4,412	**14,252**	11,403
Early redemption expense	**—**	325	**—**	325
Financing and interest	**$ 68,065**	$ 25,753	**$ 126,287**	$ 77,074

16. FOREIGN EXCHANGE

	Three Months Ended September 30		Nine Months Ended September 30	
	2023	2022	**2023**	2022
Unrealized foreign exchange loss - long-term notes & Credit Facilities	**$ 42,392**	$ 39,799	**$ 29,299**	$ 52,750
Realized foreign exchange loss (gain)	**290**	(894)	**1,381**	(481)
Foreign exchange loss	**$ 42,682**	$ 38,905	**$ 30,680**	$ 52,269

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade receivables and prepaids, trade and other payables, financial derivatives, Credit Facilities, and long-term notes. The fair value of trade receivables and prepaids 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:

	September 30, 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	**$ 6,695**	**$ 6,695**	$ 10,105	$ 10,105	Level 2
Total	**$ 6,695**	**$ 6,695**	$ 10,105	$ 10,105	
Amortized cost					
Cash	**$ 23,899**	**$ 23,899**	$ 5,464	$ 5,464	—
Trade receivables and prepaids	**540,679**	**540,679**	228,485	228,485	—
Total	**$ 564,578**	**$ 564,578**	$ 233,949	$ 233,949	
Financial Liabilities					
Fair value through profit and loss					
Financial derivatives	**$ (12,793)**	**$ (12,793)**	$ —	$ —	Level 2
Total	**$ (12,793)**	**$ (12,793)**	$ —	$ —	
Amortized cost					
Trade and other payables	**$ (685,392)**	**$ (685,392)**	$ (281,404)	$ (281,404)	—
Dividends payable	**(19,138)**	**(19,138)**	—	—	—
Credit Facilities	**(1,028,867)**	**(1,046,756)**	(383,031)	(385,394)	—
Long-term notes	**(1,600,397)**	**(1,676,488)**	(547,598)	(563,292)	Level 1
Total	**$ (3,333,794)**	**$ (3,427,774)**	$ (1,212,033)	$ (1,230,090)	

There were no transfers between Level 1 and Level 2 during the nine months ended September 30, 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	
	September 30, 2023	December 31, 2022	**September 30, 2023**	December 31, 2022
U.S. dollar denominated	**US$5,041**	US$6,980	**US$1,448,655**	US$430,171

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding subsequent to September 30, 2023 and as of November 2, 2023:

	Remaining Period	Volume	Price/Unit [1]	Index
Oil				
Basis differential [2]	Oct 2023 to Dec 2023	1,500 bbl/d	WTI less US$2.50/bbl	MSW
Basis differential [2]	Jan 2024 to Dec 2024	1,500 bbl/d	WTI less US$2.65/bbl	MSW
Basis differential [2]	Oct 2023 to Dec 2023	8,000 bbl/d	WTI less US$13.96/bbl	WCS
Basis differential [2]	Oct 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
Basis differential [2]	Jan 2024 to Jun 2024	4,000 bbl/d	Baytex pays: WCS differential at Hardisty Baytex receives: WCS differential at Houston less US$8.10/bbl	WCS
Put option	Oct 2023 to Dec 2023	5,000 bbl/d	US$60.00	WTI
Collar	Oct 2023 to Dec 2023	30,589 bbl/d	US$60.00/US$100.00	WTI
Collar	Jan 2024 to Mar 2024	10,400 bbl/d	US$60.00/US$100.00	WTI
Collar	Jan 2024 to Jun 2024	24,500 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$90.21	WTI
Collar	Apr 2024 to Jun 2024	11,750 bbl/d	US$60.00/US$100.00	WTI
Collar	July 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$94.15	WTI
Collar	July 2024 to Dec 2024	5,000 bbl/d	US$60.00/US$100.00	WTI
Collar [3]	July 2024 to Sep 2024	10,000 bbl/d	US$60.00/US$100.00	WTI
Collar [3]	Oct 2024 to Dec 2024	2,500 bbl/d	US$60.00/US$100.00	WTI
Collar [3]	July 2024 to Dec 2024	5,000 bbl/d	US$60.00/US$100.00	WTI
Natural Gas				
Basis differential [2]	Oct 2023 to Dec 2023	11,413 mmbtu/d	Baytex pays: NYMEX Baytex receives: HSC less US$0.1525/mmbtu	HSC
Fixed Sell	Oct 2023 to Mar 2024	3,500 mmbtu/d	US$3.5025	NYMEX
Collar	Oct 2023 to Dec 2023	11,413 mmbtu/d	US$2.50/US$2.68	NYMEX
Collar	Jan 2024 to Mar 2024	11,538 mmbtu/d	US$2.50/US$3.65	NYMEX
Collar	Apr 2024 to Jun 2024	11,538 mmbtu/d	US$2.33/US$3.00	NYMEX
Collar	Jan 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.06	NYMEX
Collar	Jan 2024 to Dec 2024	2,500 mmbtu/d	US$3.00/US$4.09	NYMEX
Collar	Jan 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.10	NYMEX
Collar	Jan 2024 to Dec 2024	8,500 mmbtu/d	US$3.00/US$4.15	NYMEX
Collar	Jan 2024 to Dec 2024	5,000 mmbtu/d	US$3.00/US$4.19	NYMEX
Natural Gas Liquids				
Fixed Sell	Oct 2023 to Mar 2024	34,364 gallon/d	US$0.2280/gallon	Mt. Belvieu Non-TET Ethane

(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) Contract entered subsequent to September 30, 2023.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2023	2022	**2023**	2022
Realized financial derivatives (gain) loss	**$ (2,055)**	$ 76,408	**$ (23,835)**	$ 284,816
Unrealized financial derivatives loss (gain)	**30,696**	(190,471)	**40,889**	(92,978)
Financial derivatives loss (gain)	**$ 28,641**	$ (114,063)	**$ 17,054**	$ 191,838

18. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain a strong balance sheet that provides financial flexibility to execute its development programs, provide returns to shareholders and optimize its portfolio through strategic acquisitions. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At September 30, 2023, the Company's capital structure was comprised of shareholders' capital, long-term notes, trade receivables and prepaids, trade and other payables, dividends payable, cash and the Credit Facilities.

In order to manage its capital structure and liquidity, Baytex may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

Net Debt

The Company uses net debt to monitor its current financial position and to evaluate existing sources of liquidity. The Company defines net debt to be the sum of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade and other payables, dividends payable, cash, and trade receivables and prepaids. Baytex also uses net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations.

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

	September 30, 2023	December 31, 2022
Credit Facilities	**$ 1,028,867**	$ 383,031
Unamortized debt issuance costs - Credit Facilities (note 7)	**17,889**	2,363
Long-term notes	**1,600,397**	547,598
Unamortized debt issuance costs - Long-term notes (note 8)	**37,243**	6,999
Trade and other payables	**685,392**	281,404
Dividends payable	**19,138**	—
Cash	**(23,899)**	(5,464)
Trade receivables and prepaids	**(540,679)**	(228,485)
Net Debt	**$ 2,824,348**	$ 987,446

Adjusted Funds Flow

Adjusted funds flow is used to monitor operating performance and the Company's ability to generate funds for exploration and development expenditures and settlement of abandonment obligations. Adjusted funds flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, asset retirements obligations settled during the applicable period, transaction costs and cash premiums on derivatives.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2023	2022	**2023**	2022
Cash flows from operating activities	**$ 444,033**	$ 310,423	**$ 821,279**	$ 869,431
Change in non-cash working capital	**126,075**	(30,734)	**205,924**	29,560
Asset retirement obligations settled	**9,252**	4,599	**18,770**	10,608
Transaction costs	**2,263**	—	**43,966**	—
Cash premiums on derivatives	**—**	—	**2,263**	—
Adjusted Funds Flow	**$ 581,623**	$ 284,288	**$ 1,092,202**	$ 909,599

CORPORATE INFORMATION

BOARD OF DIRECTORS

Mark R. Bly
Chairman of the Board

Eric T. Greager
Director

Tiffany (TJ) Thom Cepak [1,3]
Director

Trudy M. Curran [2,4]
Director

Don G. Hrap [1,3]
Director

Angela S. Lekatsas [1,4]
Director

Jennifer A. Maki [1,2]
Director

David L. Pearce [2,3]
Director

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

Jeffrey E. Wojahn [2,4]
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

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OFFICERS

Eric T. Greager
President and
Chief Executive Officer

Chad L. Kalmakoff
Chief Financial Officer

Chad E. Lundberg
Chief Operating Officer

James R. Maclean
Chief Legal Officer and
Corporate Secretary

Brian G. Ector
Senior Vice President,
Capital Markets and Investor Relations

Kendall D. Arthur
Senior Vice President and
General Manager, Canadian
Heavy Oil Operations

Julia Gwaltney
Senior Vice President and
General Manager, U.S. Eagle
Ford Operations

Nicole M. Frechette
Vice President and General Manager,
Canadian Light Oil Operations

Chris Lessoway
Vice President, Finance
and Treasurer

Kayla D. Baird
Vice President, U.S. Accounting
and Corporate Services

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