BAYTEX ANNOUNCES SECOND QUARTER 2023 RESULTS

CALGARY, ALBERTA (July 27, 2023) - Baytex Energy Corp. ("Baytex") (TSX:BTE) (NYSE:BTE) reports its operating and financial results for the three and six months ended June 30, 2023 (all amounts are in Canadian dollars unless otherwise noted).

"We continue to execute on our base business, and following the Ranger transaction, have emerged as a well-capitalized and diversified North American exploration and production company. We have a strong portfolio of high-quality oil weighted assets in Western Canada and the Eagle Ford shale in Texas and we are poised to deliver a powerful combination of free cash flow and increased shareholder returns on a per-share basis. We have initiated our share buyback program (repurchased 4.7 million shares to-date in July) and declared a quarterly dividend of $0.0225 per share ($0.09 per share annualized). We are committed to operational excellence and delivering long-term value and enhanced shareholder returns," commented Eric T. Greager, President and Chief Executive Officer.

Highlights

- Completed the acquisition of Ranger Oil Corporation ("Ranger") on June 20, 2023.
- Generated production of 89,761 boe/d (86% oil and NGLs) in Q2/2023.
- Reported cash flows from operating activities of $192 million ($0.33 per basic share) in Q2/2023.
- Delivered adjusted funds flow(1) of $274 million ($0.47 per basic share) in Q2/2023.
- Generated free cash flow(2) of $96 million ($0.17 per basic share) in Q2/2023.
- Exploration and development expenditures totaled $171 million in Q2/2023, consistent with our full-year plan.
- Completed six-well Duvernay program with wells onstream in Q3/2023.
- New heavy oil exploration success in Waseca near Cold Lake, Alberta.

On June 20, 2023, we closed the acquisition of Ranger, adding quality scale in the Eagle Ford and reinforcing a resilient and sustainable business. The total consideration paid by Baytex, including assumption of net debt(1), was US$2.4 billion (C$3.2 billion). 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. Our second quarter results include 11 days of operations from Ranger.

In conjunction with closing of the acquisition, we increased our direct shareholder returns to 50% of free cash flow(2) which will allow 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 debt reduction.

On June 23, 2023, we renewed our Normal Course Issuer Bid with the Toronto Stock Exchange for a share buyback program for up to 10% of our public float. Through July 26, 2023, we have repurchased 4.7 million common shares at an average price of $4.59 per share.

The Board of Directors has declared a quarterly cash dividend of $0.0225 per share to be paid on October 2, 2023 for shareholders of record on September 15, 2023(3)

(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.
(3) Refer to the dividend advisory section in this press release for further information.

2023 Outlook

Following the Ranger transaction, Baytex has emerged as a well-capitalized, diversified oil-weighted North American E&P company with a strong free cash flow profile. Based on the forward strip[(1)], we expect to generate over $400 million of free cash flow[(2)] in the second half of 2023, and approximately $500 million of free cash flow for the full-year 2023.

For 2023, we continue to forecast exploration and development expenditures of $1,005 to $1,045 million, which are expected to generate an average production rate of 120,500 to 122,500 boe/d. For the second half of 2023, we expect production to average 153,000 to 157,000 boe/d. Our production mix for the second half of 2023 is forecast to be 84% oil and NGLs (50% light oil, 22% heavy oil and 12% NGLs) and 16% natural gas.

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

	H1/2023 Actual	**H2/2023 Guidance**	**2023 Guidance**
Production (boe/d)	88,269 [(3)]	153,000-157,000	120,500-122,500
Exploration and development expenditures ($ millions)	$404	$601-$641	$1,005-$1,045

We have updated our full-year 2023 cost assumptions to reflect the Ranger acquisition. Guidance for unit operating expenses decreased by 13% to reflect the lower cost structure of the Ranger asset base, while unit general and administrative expenses increased by 10% to reflect costs associated with Ranger personnel, and interest expense is higher due to the incremental debt associated with the Ranger acquisition as well as higher interest rates on the credit facility due to the rising interest rate environment.

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

	2023 Original Guidance [(4)]	**2023 Revised Guidance [(5)]**
Expenses:		
Average royalty rate [(2)]	20.0 - 22.0%	21.0 - 22.0%
Operating [(6)]	$14.00 - $14.75/boe	$12.25 - $12.75/boe
Transportation [(6)]	$1.90 - $2.10/boe	$2.00 - $2.10/boe
General and administrative [(6)]	$52 million ($1.63/boe)	$80 million ($1.80/boe)
Interest [(6)]	$65 million ($2.04/boe)	$150 million ($3.38/boe)
Leasing expenditures	$4 million	$13 million
Asset retirement obligations	$25 million	$25 million

(1) H2/2023 commodity prices: WTI - US$75/bbl, WCS differential to WTI - US$14/bbl, NYMEX Gas - US$2.85/MMbtu; Exchange Rate (CAD/USD) - 1.32.
(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) As announced on December 7, 2022.
(5) 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.

	Three Months Ended			Six Months Ended	
	June 30, 2023	March 31, 2023	June 30, 2022	**June 30, 2023**	June 30, 2022
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 598,760**	$ 555,336	$ 854,169	**$ 1,154,096**	$ 1,527,994
Adjusted funds flow (1)	**273,590**	236,989	345,704	**510,579**	625,311
Per share – basic	**0.47**	0.43	0.61	**0.90**	1.10
Per share – diluted	**0.47**	0.43	0.60	**0.90**	1.10
Free cash flow (2)	**96,313**	(1,918)	245,316	**94,395**	366,634
Per share – basic	**0.17**	—	0.43	**0.17**	0.65
Per share – diluted	**0.16**	—	0.43	**0.17**	0.64
Cash flows from operating activities	**192,308**	184,938	360,034	**377,246**	559,008
Per share – basic	**0.33**	0.34	0.63	**0.67**	0.99
Per share – diluted	**0.33**	0.34	0.63	**0.66**	0.98
Net income	**213,603**	51,441	180,972	**265,044**	237,830
Per share – basic	**0.37**	0.09	0.32	**0.47**	0.42
Per share – diluted	**0.36**	0.09	0.32	**0.47**	0.42
Capital Expenditures					
Exploration and development expenditures	**$ 170,704**	$ 233,626	$ 96,633	**$ 404,330**	$ 250,455
Acquisitions and divestitures	**(112)**	271	194	**159**	226
Total oil and natural gas capital expenditures	**$ 170,592**	$ 233,897	$ 96,827	**$ 404,489**	$ 250,681
Net Debt					
Credit facilities	**$ 986,903**	$ 409,653	$ 496,917	**$ 986,903**	$ 496,917
Long-term notes	**1,601,468**	554,351	643,600	**1,601,468**	643,600
Long-term debt	**2,588,371**	964,004	1,140,517	**2,588,371**	1,140,517
Working capital	**226,473**	31,166	(17,220)	**226,473**	(17,220)
Net debt (1)	**$ 2,814,844**	$ 995,170	$ 1,123,297	**$ 2,814,844**	$ 1,123,297
Shares Outstanding - basic (thousands)					
Weighted average	**583,365**	545,062	566,997	**564,319**	566,262
End of period	**862,192**	545,553	560,139	**862,192**	560,139
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 73.78**	$ 76.13	$ 108.41	**$ 74.96**	$ 101.35
MEH oil (US$/bbl)	**75.01**	77.42	112.41	**76.22**	104.56
MEH oil differential to WTI (US$/bbl)	**1.23**	1.29	4.00	**1.26**	3.21
Edmonton par ($/bbl)	**95.13**	99.04	137.79	**97.09**	126.72
Edmonton par differential to WTI (US$/bbl)	**(2.95)**	(2.88)	(0.47)	**(2.91)**	(1.68)
WCS heavy oil ($/bbl)	**78.85**	69.44	122.05	**74.16**	111.48
WCS differential to WTI (US$/bbl)	**(15.07)**	(24.77)	(12.80)	**(19.92)**	(13.67)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.10**	$ 3.42	$ 7.17	**$ 2.76**	$ 6.06
AECO ($/mcf)	**2.35**	4.34	6.27	**3.34**	5.43
CAD/USD average exchange rate	**1.3431**	1.3520	1.2766	**1.3475**	1.2714

	Three Months Ended			Six Months Ended	
	June 30, 2023	March 31, 2023	June 30, 2022	**June 30, 2023**	June 30, 2022
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**35,322**	31,678	33,007	**33,510**	33,533
Heavy oil (bbl/d)	**32,821**	34,191	28,586	**33,502**	26,921
NGL (bbl/d)	**8,620**	7,213	7,468	**7,920**	7,552
Total liquids (bbl/d)	**76,763**	73,082	69,061	**74,932**	68,006
Natural gas (mcf/d)	**77,989**	82,066	84,169	**80,017**	83,873
Oil equivalent (boe/d @ 6:1) (3)	**89,761**	86,760	83,090	**88,269**	81,985
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 545,765**	$ 495,655	$ 797,274	**$ 1,041,420**	$ 1,429,659
Royalties	**(107,920)**	(93,253)	(171,559)	**(201,173)**	(294,279)
Operating expense	**(119,438)**	(112,408)	(107,426)	**(231,846)**	(208,192)
Transportation expense	**(14,574)**	(17,005)	(11,758)	**(31,579)**	(20,973)
Operating netback (2)	**$ 303,833**	**$ 272,989**	**$ 506,531**	**$ 576,822**	**$ 906,215**
General and administrative	**(15,240)**	(11,734)	(11,640)	**(26,974)**	(23,322)
Cash financing and interest	**(28,255)**	(18,375)	(20,474)	**(46,630)**	(40,901)
Realized financial derivatives gain (loss)	**16,365**	5,415	(124,042)	**21,780**	(208,408)
Other (4)	**(3,113)**	(11,306)	(4,671)	**(14,419)**	(8,273)
Adjusted funds flow (1)	**$ 273,590**	**$ 236,989**	**$ 345,704**	**$ 510,579**	**$ 625,311**
Netback (per boe) (5)					
Total sales, net of blending and other expense (2)	**$ 66.82**	$ 63.48	$ 105.44	**$ 65.18**	$ 96.34
Royalties	**(13.21)**	(11.94)	(22.69)	**(12.59)**	(19.83)
Operating expense	**(14.62)**	(14.40)	(14.21)	**(14.51)**	(14.03)
Transportation expense	**(1.78)**	(2.18)	(1.56)	**(1.98)**	(1.41)
Operating netback (2)	**$ 37.21**	**$ 34.96**	**$ 66.98**	**$ 36.10**	**$ 61.07**
General and administrative	**(1.87)**	(1.50)	(1.54)	**(1.69)**	(1.57)
Cash financing and interest	**(3.46)**	(2.35)	(2.71)	**(2.92)**	(2.76)
Realized financial derivatives gain (loss)	**2.00**	0.69	(16.41)	**1.36**	(14.04)
Other (4)	**(0.39)**	(1.45)	(0.60)	**(0.89)**	(0.56)
Adjusted funds flow (1)	**$ 33.49**	**$ 30.35**	**$ 45.72**	**$ 31.96**	**$ 42.14**

Notes:

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(4) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and cash share-based compensation. Refer to the Q2/2023 MD&A for further information on these amounts.
(5) Calculated as royalties, operating, transportation, general and administrative, cash financing and interest expense or realized financial derivatives loss divided by barrels of oil equivalent production volume for the applicable period.

Q2/2023 Results

We continue to execute on our base business. Production In Q2/2023 was 89,761 boe/d (86% oil and NGLs), which includes production from Ranger for the 11 days following closing of the acquisition. Production exceeded the high end of our Q2/2023 guidance range of 88,500 to 89,000 boe/d due to the timing of operated Eagle Ford wells brought onstream late in the second quarter.

Production in Q2/2023 was reduced by approximately 4,500 boe/d due to the temporary curtailment of production caused by wildfires in Alberta. For the month of July, we expect production to be curtailed by approximately 2,000 boe/d. Wildfires continue to burn in northwest Alberta and we could see further interruptions through the summer and into the fall. We are incredibly proud of how our personnel have responded with sound, safety-focused decision making.

We delivered adjusted funds flow(1) of $274 million ($0.47 per basic share) and net income of $214 million ($0.37 per basic share) in Q2/2023. Exploration and development expenditures totaled $171 million in Q2/2023 and we brought 43 (34.9 net) wells onstream. During the second quarter, we generated free cash flow(2) of $96 million ($0.17 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 net acres in the crude oil window and on-trend with our non-operated position in the Karnes Trough. The transaction increased our exposure to premium U.S. Gulf Coast pricing and included substantial infrastructure in place with low operating and transportation costs.

Production in the Eagle Ford averaged 33,887 boe/d (82% oil and NGLs) during Q2/2023, and includes 11 days of production from the Ranger assets. During the second quarter, we brought 13 (4.9 net) wells onstream, including 2 (2.0 net) operated wells. We expect to bring approximately 24 net operated wells and 8 net non-operated wells to sales in H2/2023.

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 the potential for strong economics and organic growth.

Our light oil production in Canada averaged 17,029 boe/d (86% oil and NGLs) during Q2/2023. In the Viking, we brought 28 (28.0 net) wells onstream in Q2/2023 and expect to bring another 46 net wells onstream in H2/2023. In the Pembina Duvernay, we commenced completion activities for the six wells (two-three well pads) drilled this year. Our completions and facility execution tracked ahead of plan, which allowed for an acceleration of the on-streaming of wells. Four of the six wells are in the early stages of flow back and are tracking to type curve initial rate expectations. The remaining two wells are expected to be onstream by mid-August.

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 34,955 boe/d (94% oil and NGLs) during Q2/2023. We brought onstream two net wells during the second quarter, which typically has lower activity due to spring breakup. Our heavy oil development program has ramped up in the third quarter with four rigs running, two at Peavine, one at Peace River and one at Lloydminster. In H2/2023, we expect to bring 40 net heavy oil wells onstream, 19 at Peavine, 18 at Lloydminster and 3 at Peace River.

In Q1/2023 we successfully drilled a six-leg Upper Waseca multi-lateral horizontal exploration well at Cold Lake, Alberta. The well was brought onstream in April and achieved a 30-day initial production rate of 165 bbl/d of 12.5° API crude oil. The Waseca formation is analogous to Clearwater reservoirs across the fairway and is highly amenable to open-hole development which drives strong returns and capital efficiencies. We are encouraged by this initial test result and are planning 3 follow-up wells in the second half of 2023, including a Lower Waseca test. We hold 20 prospective sections across the play. In addition, we will follow up our successful Q4/2022 Clearwater test well at Morinville, Alberta with two additional wells in the second half of 2023.

(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.

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, and a US$150 million two-year term loan.

Our total debt[(1)], which includes our two series of long-term notes, is $2.6 billion as at June 30, 2023 and we maintain strong liquidity with approximately 40% undrawn capacity on our revolving credit facility.

Risk Management

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

For Q3/2023 and Q4/2023, we have entered into hedges on approximately 40% and 35% of our net crude oil exposure, respectively, 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 22% of our net crude oil exposure utilizing two-way collars with a floor price of US$60/bbl and a ceiling price of US$99/bbl.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q2/2023 financial statements.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 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.sedar.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.sedar.com.

Conference Call Tomorrow
9:00 a.m. MDT (11:00 a.m. EDT)

Baytex will host a conference call tomorrow, July 28, 2023, starting at 9:00am MDT (11:00am EDT). To participate, please dial toll free in North America 1-800-319-4610 or international 1-416-915-3239. Alternatively, to listen to the conference call online, please enter https://services.choruscall.ca/links/baytex2023q2.html in your web browser.

An archived recording of the conference call will be available shortly after the event by accessing the webcast link above. The conference call will also be archived on the Baytex website at www.baytexenergy.com.

Advisory Regarding Forward-Looking Statements

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

Specifically, this press release contains forward-looking statements relating to but not limited to: that we are poised to deliver a powerful combination of free cash flow and increased shareholder returns on a per-share basis; we are committed to operational excellence and delivering long-term value and enhanced shareholder returns; expectations regarding our intention to further strengthen our balance sheet and the allocation of free cash flow, including with respect to debt repayment and shareholder returns; we expect to generate over $400 million of free cash flow in the second half of 2023, and approximately $500 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; we could be impacted by Alberta wildfires through summer and fall; our plans and expectations in respect of our drilling program, including the number of net wells to be brought on line in H2/2023 and the location of such wells and 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; 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.

This press release contains information that may be considered a financial outlook under applicable securities laws about Baytex's pro forma capitalization upon completion of the Merger, which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth herein. The actual capitalization of Baytex will vary from the amounts set forth in this press release and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, Baytex undertakes no obligation to update such financial outlook. The financial outlook contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about Baytex's potential future capitalization upon completion of the Merger. Readers are cautioned that the financial outlook contained in this press release is not conclusive and is subject to change.

Dividend Advisory

Future dividends and share buybacks, 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) 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.

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 June 30		Six Months Ended June 30	
($ thousands)	**2023**	2022	**2023**	2022
Petroleum and natural gas sales	**$ 598,760**	$ 854,169	**$ 1,154,096**	$ 1,527,994
Blending and other expense	**(52,995)**	(56,895)	**(112,676)**	(98,335)
Total sales, net of blending and other expense	**545,765**	797,274	**1,041,420**	1,429,659
Royalties	**(107,920)**	(171,559)	**(201,173)**	(294,279)
Operating expense	**(119,438)**	(107,426)	**(231,846)**	(208,192)
Transportation expense	**(14,574)**	(11,758)	**(31,579)**	(20,973)
Operating netback	**$ 303,833**	$ 506,531	**$ 576,822**	$ 906,215

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 June 30		Six Months Ended June 30	
($ thousands)	**2023**	2022	**2023**	2022
Cash flows from operating activities	**$ 192,308**	$ 360,034	**$ 377,246**	$ 559,008
Change in non-cash working capital	**40,795**	(17,046)	**79,849**	60,294
Additions to exploration and evaluation assets	**(741)**	(2,338)	**(1,231)**	(5,897)
Additions to oil and gas properties	**(169,963)**	(94,295)	**(403,099)**	(244,558)
Payments on lease obligations	**(1,181)**	(1,039)	**(2,336)**	(2,213)
Transaction costs	**32,832**	—	**41,703**	—
Cash premiums on derivatives	**2,263**	—	**2,263**	—
Free cash flow	**$ 96,313**	$ 245,316	**$ 94,395**	$ 366,634

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 and other receivables. 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)	**June 30, 2023**	December 31, 2022
Credit facilities	**$ 964,332**	$ 383,031
Unamortized debt issuance costs - Credit facilities (1)	**22,571**	2,363
Long-term notes	**1,563,897**	547,598
Unamortized debt issuance costs - Long-term notes (1)	**37,571**	6,999
Trade and other payables	**616,608**	281,404
Cash	**(19,637)**	(5,464)
Trade and other receivables	**(370,498)**	(228,485)
Net debt	**$ 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 six months ended June 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 June 30		Six Months Ended June 30	
($ thousands)	**2023**	2022	**2023**	2022
Cash flow from operating activities	**$ 192,308**	$ 360,034	**$ 377,246**	$ 559,008
Change in non-cash working capital	**40,795**	(17,046)	**79,849**	60,294
Asset retirement obligations settled	**5,392**	2,716	**9,518**	6,009
Transaction costs	**32,832**	—	**41,703**	—
Cash premiums on derivatives	**2,263**	—	**2,263**	—
Adjusted funds flow	**$ 273,590**	$ 345,704	**$ 510,579**	$ 625,311

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 six months ended June 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 June 30, 2023					Three Months Ended June 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	9,801	6	49	11,117	11,708	10,216	10	31	12,471	12,336
Lloydminster	11,398	23	—	1,228	11,625	11,051	8	—	1,729	11,347
Peavine	11,622	—	—	—	11,622	7,319	—	—	—	7,319
Canada - Light										
Viking	—	13,265	181	12,105	15,464	—	14,103	184	13,202	16,487
Duvernay	—	675	566	1,946	1,565	—	801	620	2,007	1,756
Remaining Properties	—	643	638	15,647	3,890	—	753	983	23,627	5,674
United States										
Eagle Ford	—	20,710	7,186	35,946	33,887	—	17,332	5,650	31,133	28,170
Total	32,821	35,322	8,620	77,989	89,761	28,586	33,007	7,468	84,169	83,090

	Six Months Ended June 30, 2023					Six Months Ended June 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	10,289	9	51	11,191	12,215	10,898	8	30	11,801	12,902
Lloydminster	11,522	17	—	1,223	11,743	10,775	11	—	1,758	11,079
Peavine	11,691	—	—	—	11,691	5,248	—	—	—	5,248
Canada - Light										
Viking	—	13,948	187	11,864	16,113	—	14,894	186	12,552	17,172
Duvernay	—	868	754	2,283	2,002	—	896	705	2,174	1,963
Remaining Properties	—	658	661	19,001	4,485	—	810	956	24,158	5,792
United States										
Eagle Ford	—	18,010	6,267	34,455	30,020	—	16,914	5,675	31,430	27,828
Total	33,502	33,510	7,920	80,017	88,269	26,921	33,533	7,552	83,873	81,985

Baytex Energy Corp.

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

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

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

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