BAYTEX ANNOUNCES SECOND QUARTER 2021 FINANCIAL AND OPERATING RESULTS, FREE CASH FLOW OF $112 MILLION AND REPURCHASE OF LONG-TERM NOTES

CALGARY, ALBERTA (July 28, 2021) - Baytex Energy Corp. ("Baytex")(TSX: BTE) reports its operating and financial results for the three and six months ended June 30, 2021 (all amounts are in Canadian dollars unless otherwise noted).

"During the second quarter, we delivered strong operating results and substantial free cash flow. Our free cash flow profile continues to improve resulting in accelerated debt reduction. We are taking proactive measures to reduce our net debt with the repurchase and cancellation of US$106 million of our outstanding long-term notes due 2024 during and subsequent to the quarter. At current commodity prices, we now expect to generate over $350 million of free cash flow in 2021. In addition, we are drilling our fourth follow up well as we continue to advance our exciting, new, oil discovery in the Clearwater play in Peace River," commented Ed LaFehr, President and Chief Executive Officer.

Q2 2021 Highlights

- Generated production of 81,162 boe/d (81% oil and NGL), a 3% increase over Q1/2021.
- Delivered adjusted funds flow of $176 million ($0.31 per basic share), a 12% increase compared to $157 million ($0.28 per basic share) in Q1/2021.
- Generated free cash flow of $112 million ($0.20 per basic share).
- Realized an operating netback of $33.92/boe, up from $29.80/boe in Q1/2021.
- Repurchased and cancelled US$5.8 million principal amount of 5.625% long-term notes. Subsequent to quarter-end, repurchased and cancelled an additional US$100 million principal amount of 5.625% long-term notes.
- Reduced net debt by $129 million through a combination of free cash flow and the Canadian dollar strengthening relative to the U.S. dollar.

2021 Outlook

As a result of our strong operating performance through the first half of 2021, we are increasing our production guidance to 79,000 to 80,000 boe/d, up from 77,000 to 79,000 boe/d, previously. We continue to forecast 2021 exploration and development expenditures of $285 to $315 million. Our free cash flow profile continues to improve as we benefit from our diversified oil weighted portfolio and our commitment to allocate capital effectively. At current commodity prices, we now expect to deliver over $350 million ($0.62 per basic share) of free cash flow this year, which will accelerate our debt reduction efforts.

Five-Year Outlook

Our five-year outlook (2021 to 2025) highlights our financial and operational sustainability and meaningful free cash flow generation. Through this plan period, we are committed to a disciplined and returns based capital allocation philosophy.

We have updated year one of our five-year outlook (2021) to reflect year-to-date commodity prices and the forward strip for the balance of the year. The remaining years (2022 to 2025) continue to be based on a constant US$55/bbl WTI price. Under the plan, we expect to generate over $1 billion of cumulative free cash flow as we target capital expenditures at less than 70% of our adjusted funds flow, while optimizing production in the 80,000 to 85,000 boe/d range. Under constant US$60/bbl and $65/bbl WTI pricing scenarios, we expect to generate in excess of $1.5 billion and $2.0 billion of cumulative free cash flow, respectively.

Based on the strong pricing environment and free cash flow forecast for 2021, we have accelerated our debt repayment strategy by approximately one year over the base plan presented last quarter. We now anticipate hitting our net debt target of $1.0 to $1.2 billion in 2023 at US$55/bbl. Throughout the plan period we will continue to monitor our leverage position and assess market conditions to determine the best methods or combination thereof to enhance shareholder returns. These could include share buy-backs, a dividend and/or reinvestment for organic growth.

	Three Months Ended			Six Months Ended	
	June 30, 2021	March 31, 2021	June 30, 2020	**June 30, 2021**	June 30, 2020
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 442,354**	$ 384,702	$ 152,689	**$ 827,056**	$ 489,303
Adjusted funds flow (1)	**175,883**	156,582	17,887	**332,465**	150,822
Per share - basic	**0.31**	0.28	0.03	**0.59**	0.27
Per share - diluted	**0.31**	0.28	0.03	**0.59**	0.27
Net income (loss)	**1,052,999**	(35,352)	(138,463)	**1,017,647**	(2,636,680)
Per share - basic	**1.87**	(0.06)	(0.25)	**1.81**	(4.71)
Per share - diluted	**1.85**	(0.06)	(0.25)	**1.79**	(4.71)
Capital Expenditures					
Exploration and development expenditures (1)	**$ 61,485**	$ 83,588	$ 9,852	**$ 145,073**	$ 186,629
Acquisitions, net of divestitures	**(18)**	(203)	(11)	**(221)**	(51)
Total oil and natural gas capital expenditures	**$ 61,467**	$ 83,385	$ 9,841	**$ 144,852**	$ 186,578
Net Debt					
Credit facilities (2)	**$ 486,623**	$ 606,637	$ 704,135	**$ 486,623**	$ 704,135
Long-term notes (2)	**1,109,211**	1,131,480	1,225,395	**1,109,211**	1,225,395
Long-term debt	**1,595,834**	1,738,117	1,929,530	**1,595,834**	1,929,530
Working capital deficiency	**33,795**	20,777	65,423	**33,795**	65,423
Net debt (1)	**$ 1,629,629**	$ 1,758,894	$ 1,994,953	**$ 1,629,629**	$ 1,994,953
Shares Outstanding - basic (thousands)					
Weighted average	**564,156**	562,085	560,512	**563,126**	560,158
End of period	**564,182**	564,111	560,545	**564,182**	560,545
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 66.07**	$ 57.84	$ 27.85	**$ 61.96**	$ 37.01
MEH oil (US$/bbl)	**67.15**	59.36	26.40	**63.26**	37.97
MEH oil differential to WTI (US$/bbl)	**1.08**	1.52	(1.45)	**1.30**	0.96
Edmonton par ($/bbl)	**77.28**	66.58	29.85	**71.93**	40.64
Edmonton par differential to WTI (US$/bbl)	**(3.13)**	(5.27)	(6.31)	**(4.28)**	(7.24)
WCS heavy oil ($/bbl)	**67.03**	57.46	22.70	**62.33**	28.68
WCS differential to WTI (US$/bbl)	**(11.48)**	(12.46)	(11.47)	**(11.98)**	(16.00)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.83**	$ 2.69	$ 1.72	**$ 2.76**	$ 1.83
AECO ($/mcf)	**2.85**	2.93	1.91	**2.89**	2.03
CAD/USD average exchange rate	**1.2279**	1.2663	1.3860	**1.2471**	1.3653

	Three Months Ended			Six Months Ended	
	June 30, 2021	March 31, 2021	June 30, 2020	**June 30, 2021**	June 30, 2020
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**37,134**	35,430	38,951	**36,286**	42,333
Heavy oil (bbl/d)	**21,269**	21,989	11,832	**21,627**	20,343
NGL (bbl/d)	**7,563**	6,238	7,634	**6,904**	7,728
Total liquids (bbl/d)	**65,966**	63,657	58,417	**64,817**	70,404
Natural gas (mcf/d)	**91,172**	90,739	84,546	**90,957**	90,451
Oil equivalent (boe/d @ 6:1) (3)	**81,162**	78,780	72,508	**79,978**	85,479
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (4)	**$ 422,387**	$ 367,582	$ 147,229	**$ 789,969**	$ 462,486
Royalties	**(81,531)**	(66,950)	(29,156)	**(148,481)**	(85,876)
Operating expense	**(82,901)**	(80,548)	(73,680)	**(163,449)**	(178,150)
Transportation expense	**(7,486)**	(8,788)	(5,031)	**(16,274)**	(15,373)
Operating netback (1)	**$ 250,469**	**$ 211,296**	**$ 39,362**	**$ 461,765**	**$ 183,087**
General and administrative	**(10,610)**	(8,733)	(7,438)	**(19,343)**	(17,213)
Cash financing and interest	**(23,554)**	(24,403)	(27,387)	**(47,957)**	(55,922)
Realized financial derivatives (loss) gain	**(39,024)**	(20,768)	13,624	**(59,792)**	40,474
Other (5)	**(1,398)**	(810)	(274)	**(2,208)**	396
Adjusted funds flow (1)	**$ 175,883**	**$ 156,582**	**$ 17,887**	**$ 332,465**	**$ 150,822**
Netback (per boe)					
Total sales, net of blending and other expense (4)	**$ 57.19**	$ 51.84	$ 22.31	**$ 54.57**	$ 29.73
Royalties	**(11.04)**	(9.44)	(4.42)	**(10.26)**	(5.52)
Operating expense	**(11.22)**	(11.36)	(11.17)	**(11.29)**	(11.45)
Transportation expense	**(1.01)**	(1.24)	(0.76)	**(1.12)**	(0.99)
Operating netback (1)	**$ 33.92**	**$ 29.80**	**$ 5.96**	**$ 31.90**	**$ 11.77**
General and administrative	**(1.44)**	(1.23)	(1.13)	**(1.34)**	(1.11)
Cash financing and interest	**(3.19)**	(3.44)	(4.15)	**(3.31)**	(3.59)
Realized financial derivatives (loss) gain	**(5.28)**	(2.93)	2.06	**(4.13)**	2.60
Other (5)	**(0.20)**	(0.12)	(0.03)	**(0.15)**	0.02
Adjusted funds flow (1)	**$ 23.81**	**$ 22.08**	**$ 2.71**	**$ 22.97**	**$ 9.69**

Notes:

(1) The terms “adjusted funds flow”, “exploration and development expenditures”, “net debt” and “operating netback” do not have any standardized meaning as prescribed by Canadian Generally Accepted Accounting Principles (“GAAP”) and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. See the advisory on non-GAAP measures at the end of this press release.

(2) Principal amount of instruments. The carrying amount of debt issue costs associated with the credit facilities and long-term notes are excluded on the basis that these amounts have been paid by Baytex and do not represent an additional source of capital or repayment obligations.

(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) Realized heavy oil prices are calculated based on sales dollars, net of blending and other expense. We include the cost of blending diluent in our realized heavy oil sales price in order to compare the realized pricing on our produced volumes to the WCS benchmark.

(5) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and share-based compensation. Refer to the Q2/2021 MD&A for further information on these amounts.

Q2/2021 Results

During Q2/2021, we delivered strong operating and financial results as we executed on our plan to maximize free cash flow and reduce debt. During the quarter, we delivered adjusted funds flow of $176 million ($0.31 per basic share). This resulted in substantial quarterly free cash flow of $112 million, which along with the Canadian dollar strengthening relative to the U.S. dollar, contributed to a $129 million reduction in our net debt.

Production during the second quarter averaged 81,162 boe/d (81% oil and NGL), up 3% as compared to 78,780 boe/d (81% oil and NGL) in Q1/2021. The increased production reflects the timing of completion activity in the Eagle Ford and and strong performance across our light and heavy oil assets in Canada. Exploration and development expenditures totaled $61 million in Q2/2021 that included the drilling of 34 (19.7 net) wells with a 100% success rate.

During Q2/2021, we reported net income of $1.1 billion ($1.85 per diluted share). At June 30, 2021, we identified indicators of impairment reversal for our oil and gas properties due to the increase in forecasted commodity prices. As a result, we recorded an impairment reversal of $1.1 billion during the second quarter as the estimated recoverable amounts exceeded the carrying value of our oil and gas properties.

2021 Guidance

In 2021, we are benefiting from our diversified oil weighted portfolio and our commitment to allocate capital effectively. Based on the forward strip(1), we expect to generate over $350 million of free cash flow in 2021.

As a result of our strong operating performance through the first half of 2021, we are increasing our production guidance to 79,000 to 80,000 boe/d, up from 77,000 to 79,000 boe/d, previously. We continue to forecast 2021 exploration and development expenditures of $285 to $315 million.

Our interest expense guidance is 3% lower due to reduced net debt and the repurchase and cancellation of US$106 million principal amount of 5.625% long-term notes.

The following table highlights our updated 2021 annual guidance.

	2021 Guidance (2)	**2021 Revised Guidance**
Exploration and development expenditures	$285 - $315 million	no change
Production (boe/d)	77,000 - 79,000	79,000 - 80,000
Expenses:		
Royalty rate	18.0% - 18.5%	no change
Operating	$11.25 - $12.00/boe	no change
Transportation	$1.15 - $1.25/boe	no change
General and administrative	$42 million ($1.48/boe)	$42 million ($1.45/boe)
Interest	$98 million ($3.46/boe)	$95 million ($3.27/boe)
Leasing expenditures	$4 million	no change
Asset retirement obligations	$6 million	no change

Operating Results

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 33,957 boe/d (80% oil and NGL) during Q2/2021, as compared to 26,741 boe/d in Q1/2021. The higher volumes reflect an increased pace of completions and continued strong operating performance. During the second quarter we commenced production from 38 (10.2 net) wells, up from 24 (7.0 net) wells in Q1/2021. In Q2/2021, we invested $31 million on exploration and development in the Eagle Ford and generated an operating netback of $112 million. We expect to bring approximately 22 net wells on production in the Eagle Ford in 2021.

Notes:

(1) 2021 full-year pricing assumptions: WTI - US$64/bbl; WCS differential - US$13/bbl; MSW differential – US$4/bbl, NYMEX Gas - US$3.30/mcf; AECO Gas - $3.45/mcf and Exchange Rate (CAD/USD) - 1.26.
(2) As announced on April 29, 2021.

Production in the Viking averaged 16,301 boe/d (88% oil and NGL) during Q2/2021, as compared to 19,403 boe/d in Q1/2021. Our capital program in the second quarter included the seasonal slowdown, which resulted in the completion of 14 (14.0 net) wells, as compared to 44 (43.2 net) wells during the first quarter. In Q2/2021, we invested $17 million on exploration and development in the Viking and generated an operating netback of $72 million. We expect to bring approximately 120 net wells on production in the Viking during 2021.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 23,304 boe/d (91% oil and NGL) during the Q2/2021, as compared to 24,395 boe/d in Q1/2021. We scheduled minimal heavy oil development for the first half of 2021. Our heavy oil program kicked off in June with approximately 35 net wells planned for the year, including up to seven net wells in our Spirit River (Clearwater equivalent) play.

Peace River Clearwater

Across all of our core assets, inventory enhancement continues to be a priority. We are also committed to building and maintaining respectful relationships with Indigenous communities and creating opportunities for meaningful economic participation and inclusion. In early 2020, we executed a strategic agreement with the Peavine Métis settlement in the Peace River area that covers 60 sections of land directly to the south of our existing Seal operations. At the time, we identified significant potential for this early stage exploratory play targeting the Spirit River formation, a Clearwater formation equivalent.

Our appraisal program continues to yield encouraging results and pending continued success, sets the stage for a potential increase in activity in 2022. We plan to drill up to seven net appraisal wells in 2021, of which five net appraisal wells will occur on our Peavine lands. Across our acreage position in northwest Alberta, we estimate that over 100 sections are prospective for Clearwater development. The following table summarizes our Peavine appraisal program for 2021.

Area	Well	Spud	Rig Release	# of Laterals	30-Day Initial Production Rate (bbl/d)
Peavine	100/04-34-078-16W5	January 6	January 19	2	175
Peavine	102/04-34-078-16W5	June 15	June 21	2	175
Peavine	100/13-27-078-16W5	June 22	July 6	8	On Production July 10
Peavine	100/05-34-078-16W5	July 8	July 18	8	On Production July 22
Peavine	100/11-31-078-15W5	July 20		8	

Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 1,698 boe/d (80% oil and NGL) during Q2/2021, as compared to 2,138 boe/d in Q1/2021. We now have nine producing wells in the Pembina area and have significantly de-risked our approximately 38-kilometre long acreage fairway, where we hold 232 sections (100% working interest) of Duvernay land. We expect to bring two additional 100% working interest wells on production during the third quarter.

Financial Liquidity

Our credit facilities total approximately $1.0 billion and have a maturity date of April 2, 2024. These are not borrowing base facilities and do not require annual or semi-annual reviews. As of June 30, 2021, we had $511 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $477 million.

Our net debt, which includes our credit facilities, long-term notes and working capital, totaled $1.63 billion at June 30, 2021, down from $1.76 billion at March 31, 2021.

On May 4, 2021, we repurchased and cancelled US$5.8 million principal amount of 5.625% long-term notes. Subsequent to the quarter, we used free cash flow generated in the first half of 2021 to repurchase and cancel US$100 million principal amount of the 5.625% long-term notes at the call price of 100.938% plus accrued interest effective July 28, 2021.

Risk Management

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

For the second half of 2021, we have entered into hedges on approximately 45% of our net crude oil exposure utilizing a combination of fixed price swaps at US$45/bbl and a 3-way option structure that provides price protection at US$44.71/bbl with upside participation to US$52.42/bbl. We also have WTI-MSW differential hedges on approximately 50% of our expected net Canadian light oil exposure at US$5.03/bbl and WCS differential hedges on approximately 50% of our net expected heavy oil exposure at a WTI-WCS differential of approximately US$13.23/bbl.

For 2022, we have entered into hedges on approximately 42% of our net crude oil exposure utilizing a combination of swaptions at US$53.50/bbl and a 3-way option structure that provides price protection at US$57.76/bbl with upside participation to US$67.51/bbl. We also have WTI-MSW differential hedges on approximately 13% of our expected net Canadian light oil exposure at US$4.63/bbl and WCS differential hedges on approximately 39% of our expected net heavy oil exposure at a WTI-WCS differential of approximately US$12.53/bbl.

A complete listing of our financial derivative contracts can be found in Note 16 to our Q2/2021 financial statements.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 30, 2021 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.

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

Baytex will host a conference call tomorrow, July 29, 2021, 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 http://services.choruscall.ca/links/baytex20210729.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: our business strategies, plans and objectives; that we expect to generate over $350 million of free cash flow ($0.62 per basic share) in 2021; that our debt reduction will accelerate; our five-year outlook: including that it demonstrates financial and operational sustainability, meaningful free cash flow generation and that we are committed to disciplined and returns based philosophy for that period, the cumulative free cash flow it will generate at certain WTI oil prices and that we are targeting capital expenditures at less than 70% of adjusted funds flow; we anticipate hitting our debt target of $1.0 to $1.2 billion in 2023 at US$55 WTI; that we will monitor our leverage position and market conditions to enhance shareholder returns which could be share buy-backs, a dividend or reinvestment for organic growth; we expect to benefit from our diversified oil weighted portfolio and our commitment to allocate capital effectively; our updated guidance for 2021 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; in 2021 that we expect to: bring on production 22 net wells in the Eagle Ford and 120 in the Viking and plan to drill 35 net wells in Heavy Oil, including 6 in our Spirit River (Clearwater equivalent); that we are committed to building and maintaining respectful relationships with Indigenous communities and creating opportunities for meaningful economic participation and inclusion; the potential for increased activity in 2022 pending success in Peace River Clearwater; our drilling plans for the Clearwater lands for the remainder of 2021; that we have 100 sections of highly prospective Clearwater lands; that we expect to bring two 100% working Duvernay wells on Production in Q3/2021; and drill 2 net wells in the Duvernay; and that we have de-risked our approximately 38-kilometer acreage fairway in the Pembina Duvernay; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility; the percentage of our net exposure to crude oil, the MTI-MSW differential and WCS differential that we have hedged for H2/2021 and 2022.

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; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); the availability and cost of capital or borrowing; risks associated with our ability to exploit our properties and add reserves; availability and cost of gathering, processing and pipeline systems; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; costs to develop and operate our properties; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; retaining or replacing *our leadership and key personnel; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; results of litigation; risks associated with large projects; 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, 2020, 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.

All amounts in this press release are stated in Canadian dollars unless otherwise specified.

Non-GAAP Financial and Capital Management Measures

In this news release, we refer to certain financial measures (such as adjusted funds flow, exploration and development expenditures, free cash flow, net debt and operating netback) which do not have any standardized meaning prescribed by Canadian GAAP ("non-GAAP measures") and are considered non-GAAP measures. While adjusted funds flow, exploration and development expenditures, free cash flow, net debt and operating netback are commonly used in the oil and gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers.

Adjusted funds flow is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but 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.

In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our cash flow on a continuing basis. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three and six months ended June 30, 2021.

Exploration and development expenditures is not a measurement based on GAAP in Canada. We define exploration and development expenditures as additions to exploration and evaluation assets combined with additions to oil and gas properties. Our definition of exploration and development expenditures may not be comparable to other issuers. We use exploration and development expenditures to measure and evaluate the performance of our capital programs. The total amount of exploration and development expenditures is managed as part of our budgeting process and can vary from period to period depending on the availability of adjusted funds flow and other sources of liquidity.

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as adjusted funds flow less exploration and development expenditures (both non-GAAP measures discussed above), payments on lease obligations, and asset retirement obligations settled. 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.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of cash, trade and other accounts receivable, trade and other accounts payable, and the principal amount of both the long-term notes and the credit facilities. Our definition of net debt may not be comparable to other issuers. We believe that this measure assists in providing a more complete understanding of our cash liabilities and provides 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.

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 divided by barrels of oil equivalent sales volume for the applicable period. 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.

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 news 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, 2021. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas.

	Three Months Ended June 30, 2021					Six Months Ended June 30, 2021				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	11,293	7	25	10,722	13,112	11,729	7	25	11,697	13,711
Lloydminster	9,976	5	—	1,268	10,192	9,898	5	—	1,398	10,136
Canada - Light										
Viking	—	14,284	140	11,262	16,301	—	15,866	136	11,044	17,843
Duvernay	—	791	568	2,033	1,698	—	969	612	2,015	1,917
Remaining Properties	—	574	1,046	25,689	5,902	—	587	1,101	25,882	6,002
United States										
Eagle Ford	—	21,473	5,784	40,198	33,957	—	18,852	5,030	38,921	30,369
Total	21,269	37,134	7,563	91,172	81,162	21,627	36,286	6,904	90,957	79,978

Baytex Energy Corp.

Baytex Energy Corp. is an oil and gas corporation based in Calgary, Alberta. The company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. Approximately 81% of Baytex's production is weighted toward crude oil and natural gas liquids. Baytex's common shares trade on the Toronto 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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