BAYTEX ANNOUNCES FIRST QUARTER 2022 RESULTS, STRONG PEAVINE DRILLING, INCREASED GUIDANCE AND PLANNED SHARE BUYBACK PROGRAM

CALGARY, ALBERTA (April 28, 2022) - Baytex Energy Corp. ("Baytex")(TSX: BTE) reports its operating and financial results for the three months ended March 31, 2022 (all amounts are in Canadian dollars unless otherwise noted).

“We remain focused on capital discipline, generating free cash flow and reducing debt. We also materially advanced our Clearwater development with ten wells drilled at Peavine, including three wells averaging 30-day initial production rates of 1,100 bbl/d per well. These exceptional wells have enabled us to more than double our Clearwater production to 8,000 bbl/d today. As a result, we are pleased to increase our 2022 production guidance and add six new Clearwater wells to our Q4/2022 program. Our focus on delivering substantial free cash flow is unchanged - our updated five-year plan (2022 through 2026) is expected to generate approximately $3 billion of cumulative free cash flow. I am also excited to announce that our board of directors has approved a share buyback program that is expected to commence in May," commented Ed LaFehr, President and Chief Executive Officer.

Q1 2022 Highlights

- Generated production of 80,867 boe/d (82% oil and NGL) in Q1/2022, a 3% increase over Q1/2021.
- Delivered adjusted funds flow(1) of $280 million ($0.49 per basic share) in Q1/2022, a 78% increase compared to $157 million ($0.28 per basic share) in Q1/2021.
- Generated free cash flow(2) of $121 million ($0.21 per basic share) in Q1/2022, a 72% increase compared to $70 million ($0.13 per basic share) in Q1/2021.
- Cash flows from operating activities was $199 million ($0.35 per basic share) in Q1/2022, a 64% increase compared to $121 million ($0.22 per basic share) in Q1/2021.
- Reduced net debt(1) by 10% to $1.28 billion, from $1.41 billion at year-end 2021.
- Drilled 10 Clearwater wells at Peavine in Q1/2022 with our first three wells generating an average 30-day initial production rate of 1,100 bbl/d per well, boosting field production to 8,000 bbl/d today.
- Increasing exploration and development expenditures and production guidance given strong Peavine results and inflationary pressure.
- We intend to repurchase and cancel the remaining US$200 million principal amount of 5.625% long-term notes at par on June 1, 2022.

2022 Outlook

We remain intensely focused on maintaining capital discipline and driving meaningful free cash flow in our business. Based on the forward strip(3), we expect to generate approximately $700 million ($1.25 per basic share) of free cash flow this year. As part of our previously announced return of capital framework, we expect to allocate approximately 25% of our annual free cash flow to direct shareholder returns through a share buyback program commencing in May of 2022.

The remainder of our free cash flow will continue to be allocated to debt reduction until we achieve a net debt level of $800 million, which represents an expected net debt(1) to EBITDA(4) ratio of 1.0x at a US$55 WTI price. This level of net debt will provide us with flexibility to run our business through the commodity price cycles and generate meaningful returns for our shareholders. At current prices, we expect to achieve this net debt level in early 2023, at which point we will consider steps to further enhance shareholder returns.

(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) 2022 full-year pricing assumptions: WTI - US$94/bbl; WCS differential - US$13/bbl; MSW differential – US$2/bbl, NYMEX Gas - US$5.60/mcf; AECO Gas - $5.30/mcf and Exchange Rate (CAD/USD) - 1.26.
(4) Calculated in accordance with the Credit Facilities Agreement.

Our operational success, the continued strong economics of our drilling program and the inflationary pressures being experienced throughout our industry caused us to review our capital program for the year. We are now forecasting 2022 exploration and development expenditures of $450 to $500 million, up from $400 to $450 million, which was set in a US$65 pricing environment. The incremental capital reflects additional activity on our Clearwater lands and the Eagle Ford as well as expected capital cost inflation.

With continued strong operating momentum and production growth on our Clearwater lands, we are increasing our production guidance for 2022 to 83,000 to 85,000 boe/d, up from 80,000 to 83,000 boe/d, previously, and expect to exit 2022 producing approximately 87,000 to 88,000 boe/d.

The Clearwater has emerged as one of the most profitable plays in North America and our Q1/2022 drilling program has delivered exceptional results. As a result, we are expanding our 2022 plan to run a full one rig program at Peavine through year-end (previously budgeted plans had our drilling program wrapping up in September) which results in an incremental six wells being drilled in Q4/2022. We also anticipate drilling 2-3 net incremental wells in the Eagle Ford in H2/2022, the highest free cash flow generating asset in our portfolio. This increased activity set will result in $30 million of incremental exploration and development expenditures, which is offset by approximately $10 million of reduced light oil activity.

We have also updated our 2022 plan to reflect an incremental 8% expected capital cost inflation, which increases our exploration and development expenditures by approximately $30 million. This reflects industry cost pressures related to labour, logistics, fuel and tangible items such as steel, frac sand and chemicals. In aggregate, we are now assuming 18% capital cost inflation in 2022, as compared to 2021.

We have fine-tuned several of our cost assumptions to reflect increased royalties due to higher commodity prices and inflationary pressures on operating and transportation expenses related to labor, fuel, electricity and hauling. Offsetting these cost pressures to a certain extent is increased production and a reduction in our interest expense as our net debt is reduced.

The following table highlights our updated 2022 annual guidance.

	2022 Guidance (1)	**2022 Revised Guidance**
Exploration and development expenditures	$400 - $450 million	$450 - $500 million
Production (boe/d)	80,000 - 83,000	83,000 - 85,000
Expenses:		
Average royalty rate (2)	18.5% - 19.0%	20.0% - 20.5%
Operating (3)	$12.25 - $13.00/boe	$13.00 - $13.50/boe
Transportation (3)	$1.20 - $1.30/boe	$1.30 - $1.40/boe
General and administrative (3)	$43 million ($1.45/boe)	$43 million ($1.40/boe)
Interest (3)	$80 million ($2.70/boe)	$75 million ($2.45/boe)
Leasing expenditures	$3 million	no change
Asset retirement obligations	$20 million	no change

Notes:

(1) As announced on December 1, 2021.
(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 as operating, transportation, general and administrative or interest expense divided by barrels of oil equivalent production volume for the applicable period.

Update to Five-Year Plan

We introduced our five-year plan one year ago (April 2021) to highlight our financial and operational sustainability and ability to generate meaningful free cash flow. We continue to benchmark our results to this five-year plan and intend to update as warranted based on the macro-environment (commodity prices, cost inflation) and drilling results and activity across our land base.

We are now rolling our five-year plan forward to capture the period 2022 to 2026. Year one of the five-year plan is based on 2022 guidance and forward strip commodity prices and years two through five (2023 through 2026) are based on a constant US$75 WTI price. Our focus on delivering free cash flow is unchanged - under these pricing assumptions, we expect to generate approximately $3 billion of cumulative free cash flow(1) during the plan period.

We have also updated our five-year plan to include expected inflationary cost increases along with increased drilling on our Clearwater lands that has us drilling approximately 120 net wells through 2026. With this updated view of our land base, we expect Clearwater production to increase from zero at the beginning of 2021 to approximately 10,000 bbl/d while generating over $400 million of cumulative free cash flow. With continued success, we believe the play ultimately holds the potential for over 200 drilling locations that could support production increasing to over 15,000 bbl/d.

Through this plan period, we are committed to a disciplined, returns based capital allocation philosophy, targeting exploration and development expenditures at less than 50% of our adjusted funds flow. We expect to generate annual production growth of 2% to 4%, with production reaching approximately 95,000 boe/d in 2026.

Normal Course Issuer Bid

Given the strength of our balance sheet and consistent with our desire to offer direct shareholder returns, the Board of Directors has approved the filing of a Normal Course Issuer Bid ("NCIB") application with the TSX for a share buyback program of up to 56 million common shares, representing approximately 10% of our public float.

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

	Three Months Ended		
	March 31, 2022	December 31, 2021	March 31, 2021
FINANCIAL (thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales	**$ 673,825**	$ 552,403	$ 384,702
Adjusted funds flow [1]	**279,607**	214,766	156,582
Per share - basic	**0.49**	0.38	0.28
Per share - diluted	**0.49**	0.37	0.28
Free cash flow [2]	**121,318**	137,133	70,495
Per share – basic	**0.21**	0.24	0.13
Per share – diluted	**0.21**	0.24	0.13
Cash flows from operating activities	**198,974**	240,567	120,980
Per share – basic	**0.35**	0.43	0.22
Per share – diluted	**0.35**	0.42	0.22
Net income (loss)	**56,858**	563,239	(35,352)
Per share - basic	**0.10**	1.00	(0.06)
Per share - diluted	**0.10**	0.98	(0.06)
Capital Expenditures			
Exploration and development expenditures	**$ 153,822**	$ 73,995	$ 83,588
Acquisitions and divestitures	**32**	(5,414)	(203)
Total oil and natural gas capital expenditures	**$ 153,854**	$ 68,581	$ 83,385
Net Debt			
Credit facilities	**$ 426,858**	$ 506,514	$ 606,637
Long-term notes	**873,880**	885,920	1,131,480
Long-term debt	**1,300,738**	1,392,434	1,738,117
Working capital	**(25,058)**	17,283	20,777
Net debt [1]	**$ 1,275,680**	$ 1,409,717	$ 1,758,894
Shares Outstanding - basic (thousands)			
Weighted average	**565,518**	564,213	562,085
End of period	**569,214**	564,213	564,111
BENCHMARK PRICES			
Crude oil			
WTI (US$/bbl)	**$ 94.29**	$ 77.19	$ 57.84
MEH oil (US$/bbl)	**96.72**	78.89	59.36
MEH oil differential to WTI (US$/bbl)	**2.43**	1.70	1.52
Edmonton par ($/bbl)	**115.66**	93.29	66.58
Edmonton par differential to WTI (US$/bbl)	**(2.94)**	(3.15)	(5.27)
WCS heavy oil ($/bbl)	**100.99**	78.82	57.46
WCS differential to WTI (US$/bbl)	**(14.53)**	(14.63)	(12.46)
Natural gas			
NYMEX (US$/mmbtu)	**$ 4.95**	$ 5.83	$ 2.69
AECO ($/mcf)	**4.59**	4.94	2.93
CAD/USD average exchange rate	**1.2661**	1.2600	1.2663

	Three Months Ended		
	March 31, 2022	December 31, 2021	March 31, 2021
OPERATING			
Daily Production			
Light oil and condensate (bbl/d)	**34,065**	34,986	35,430
Heavy oil (bbl/d)	**25,236**	23,482	21,989
NGL (bbl/d)	**7,636**	7,984	6,238
Total liquids (bbl/d)	**66,937**	66,452	63,657
Natural gas (mcf/d)	**83,574**	86,029	90,739
Oil equivalent (boe/d @ 6:1) (3)	**80,867**	80,789	78,780
Netback (thousands of Canadian dollars)			
Total sales, net of blending and other expense (2)	**$ 632,385**	$ 523,382	$ 367,582
Royalties	**(122,720)**	(100,152)	(66,950)
Operating expense	**(100,766)**	(95,357)	(80,548)
Transportation expense	**(9,215)**	(8,169)	(8,788)
Operating netback (2)	**$ 399,684**	**$ 319,704**	**$ 211,296**
General and administrative	**(11,682)**	(11,481)	(8,733)
Cash financing and interest	**(20,427)**	(21,319)	(24,403)
Realized financial derivatives loss	**(84,366)**	(70,544)	(20,768)
Other (4)	**(3,602)**	(1,594)	(810)
Adjusted funds flow (1)	**$ 279,607**	**$ 214,766**	**$ 156,582**
Netback (per boe) (5)			
Total sales, net of blending and other expense (2)	**$ 86.89**	$ 70.42	$ 51.84
Royalties	**(16.86)**	(13.47)	(9.44)
Operating expense	**(13.85)**	(12.83)	(11.36)
Transportation expense	**(1.27)**	(1.10)	(1.24)
Operating netback (2)	**$ 54.91**	**$ 43.02**	**$ 29.80**
General and administrative	**(1.61)**	(1.54)	(1.23)
Cash financing and interest	**(2.81)**	(2.87)	(3.44)
Realized financial derivatives loss	**(11.59)**	(9.49)	(2.93)
Other (4)	**(0.48)**	(0.23)	(0.12)
Adjusted funds flow (1)	**$ 38.42**	**$ 28.89**	**$ 22.08**

Notes:

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(4) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and cash share-based compensation. Refer to the Q1/2022 MD&A for further information on these amounts.
(5) Calculated as royalties, operating, transportation, general and administrative, cash financing and interest or realized financial derivatives loss expense divided by barrels of oil equivalent production volume for the applicable period.

Q1/2022 Results

In Q1/2022, we delivered strong operating and financial results and continued to advance our exciting new Clearwater play in northwest Alberta.

Production during the first quarter averaged 80,867 boe/d (82% oil and NGL) as compared to 80,789 boe/d (82% oil and NGL) in Q4/2021. Exploration and development expenditures totaled $154 million in Q1/2022 and we participated in the drilling of 81 (66.7 net) wells with a 100% success rate.

We delivered adjusted funds flow(1) of $280 million ($0.49 per basic share) and net income of $57 million ($0.10 per basic share). We generated free cash flow(2) of $121 million ($0.21 per basic share) during the quarter with 100% being allocated to debt repayment, reducing net debt(1) by 10% to $1.28 billion, from $1.41 billion at year-end 2021.

Operating Results

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 27,482 boe/d (81% oil and NGL) during Q1/2022 and generated an operating netback(2) of $133 million. We invested $28 million on exploration and development in the Eagle Ford and brought 15 (4.7 net) wells onstream. We now expect to bring approximately 16-17 net wells onstream in 2022, up from our original budget of 14 net wells.

Production in the Viking averaged 17,865 boe/d (89% oil and NGL) during Q1/2022 and generated an operating netback of $128 million. We invested $56 million on exploration and development in the Viking and brought 58 (56.5 net) wells onstream. We now expect to bring approximately 135 net wells onstream in 2022, versus our original budget of 145 new wells.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster (excluding our Clearwater development program) produced a combined 24,283 boe/d (91% oil and NGL) during Q1/2022 and generated an operating netback of $99 million. We invested $36 million on exploration and development and participated in the drilling of 3 net Bluesky wells at Peace River and 11 (10.8 net) wells at Lloydminster. In 2022, we will drill approximately 9 net Bluesky wells at Peace River and 38 net wells at Lloydminster.

Peace River Clearwater

Production in the Clearwater averaged 3,154 boe/d (100% oil) during Q1/2022 and generated an operating netback of $17 million.

We followed up our 2021 appraisal program on our Peavine acreage with an exceptional Q1/2022 drilling program. We now have all 10 wells drilled during the first quarter onstream and production has increased from zero at the beginning of 2021 to approximately 8,000 bbl/d today. During the first quarter, we successfully executed our first six extended reach horizontal ("ERH") multi-lateral wells, which are utilized to provide appropriate set-backs to residents and environmentally sensitive areas. These ERH wells are among the first of their type to be drilled in western Canada and consist of four two-mile long laterals versus a more traditional well design comprised of eight one-mile laterals. Our first three ERH wells (4-25 pad) have established average 30-day initial production rates of 1,100 bbl/d per well and are the strongest Clearwater wells drilled to date in the play. In addition, four wells (5-33 pad) were brought onstream in March/April and are expected to generate 30-day initial production rates of 300 to 400 bbl/d per well. Initial well performance continues to outperform type curve assumptions and we now have seven of the top ten initial rate wells drilled to date across the play.

As we continue to progress our development plan, we have committed to drill six additional Clearwater wells during the fourth quarter. We now intend to run a full one rig program at Peavine through year-end (previously budgeted plans had our drilling program wrapping up in September). As a result, we expect to drill 24 net wells in 2022, up from our original budget of 18 net wells. Maintaining a consistent one rig program and level loading activity in the second half of 2022 will drive further efficiencies and set the stage for continued strong operating momentum heading into 2023. Development plans going forward will be comprised of both our traditional 8-lateral well design and ERH wells.

At current commodity prices, the Clearwater generates among the strongest economics within our portfolio with payouts of less than three months and has the ability to grow organically while enhancing our free cash flow profile. To-date, we have de-risked 50 sections (of our 80-section Peavine land base) and believe the lands hold the potential for greater than 200 locations. When combined with our legacy acreage position in northwest Alberta, we estimate that over 125 sections are highly prospective for Clearwater development.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
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Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 2,172 boe/d (82% oil and NGL) during Q1/2022. We invested $11 million on exploration and development in the Duvernay and drilled a three-well pad which is expected to be onstream in Q3/2022.

Financial Liquidity

Our net debt[1], which includes our credit facilities, long-term notes and working capital, totaled $1.28 billion at March 31, 2022, down from $1.41 billion at December 31, 2021. As of March 31, 2022, we had $576 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $601 million.

On April 1, 2022, we announced that we had received strong support from our lending syndicate to extend and amend our bank credit facilities. The revolving credit facilities have been extended by two years, from April 2024 to April 2026, and have been increased to US$850 million. Previously, the credit facilities totaled approximately US$815 million and were comprised of US$575 million of revolving credit facilities and a C$300 million term loan. The revolving credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews.

On June 1, 2022, we intend to repurchase and cancel the remaining US$200 million principal amount of 5.625% long-term notes due 2024 at par.

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 2022, we have entered into hedges on approximately 40% of our net crude oil exposure utilizing a combination of a 3-way option structure that provides price protection at US$57.76/bbl with upside participation to US$67.51/bbl and swaptions at US$53.50/bbl. We also have WTI-MSW differential hedges on approximately 25% of our expected net Canadian light oil exposure at US$4.43/bbl and WCS differential hedges on approximately 70% of our expected net heavy oil exposure at a WTI-WCS differential of approximately US$12.28/bbl.

For 2023, we have entered into hedges on approximately 18% of our net crude oil exposure utilizing a 3-way option structure that provides price protection at US$78.37/bbl with upside participation to US$96.12/bbl

A complete listing of our financial derivative contracts can be found in Note 16 to our Q1/2022 financial statements.

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

Additional Information

Our condensed consolidated interim unaudited financial statements for the three months ended March 31, 2022 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, April 29, 2022, 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/baytex20220429.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 focus on strong capital discipline, generating free cash flow and reducing debt; that we expect to generate ~$3 Billion of cumulative free cash flow over our updated five year plan period (2022-2026); we expect to commence a share buyback program in May; we intend to repurchase and cancel the remaining US$200 million *principal amount of 5.625% long-term notes at par on June 1, 2022; we expect to generate ~$700 million ($1.25 per basic share) of free cash flow in 2022 and allocate 25% of free cash flow to a share buyback commencing in May 2022; our expected 1.0x net debt to EBITDA ratio at a US$55 WTI price when we reach our $800 million net debt target; that we will have flexibility to run our business through commodity price cycles and generate meaningful shareholder returns when our net debt target of $800 million is reached; that we expect to reach our $800 million net debt target in early 2023 and will consider steps to further enhance shareholder returns once reached; our updated guidance for 2022 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; our expected exit production rate for 2022; that incremental capital for 2022 represents additional Clearwater and Eagle Ford activity and capital cost inflation; our plan to drill six additional wells at Peavine in Q4/2022 and 2-3 net incremental wells in the Eagle Ford in H2/2022; our expectations for capital cost inflation; with respect to our five-year plan (2022-2026): the oil price assumptions, expected free cash flow generation of $3 Billion and that our Clearwater play will increase to 10,000 bbl/d, generate $400 million of free cash flow and holds the potential for over 200 drilling locations that could support increasing production to over 15,000 bbl/d; through our five-year plan that we are committed to a disciplined, returns based capital allocation philosophy, targeting exploration and development expenditures at less than 50% of adjusted funds flow and expect to generate annual production growth of 2% to 4% with production reaching 95,000 boe/d in 2026; in 2022 that we expect to: bring on production 16-17 net wells in the Eagle Ford and 135 in the Viking; that we expect to drill 9 net Bluesky wells at Peace River, 38 net wells at Lloydminster and up to 24 Clearwater wells in 2022; that maintaining a one rig program in Peavine will drive further efficiencies in our business and provide strong operating momentum heading into 2023; that the Clearwater generates among the strongest economics in our portfolio with payouts of less than three months and has the ability to grow organically while enhancing our free cash flow profile; we have over 125 sections that are highly prospective for Clearwater development; a three well pad in the Duvernay is expected to be onstream in Q3/2022; 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 WTI-MSW differential and WCS differential that we have hedged for 2022 and the percentage of our net exposure to crude oil that we have hedged for 2023.*

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; TSX approval of our share buyback program; 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); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; results of litigation; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control.

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2021, 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 free cash flow 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. 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 March 31	
($ thousands)	**2022**	2021
Petroleum and natural gas sales	**$ 673,825**	$ 384,702
Blending and other expense	**(41,440)**	(17,120)
Total sales, net of blending and other expense	**632,385**	367,582
Royalties	**(122,720)**	(66,950)
Operating expense	**(100,766)**	(80,548)
Transportation expense	**(9,215)**	(8,788)
Operating netback	**$ 399,684**	$ 211,296

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 and payments on lease obligations. Our determination of free cash flow may not be comparable to other issuers. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities.

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

	Three Months Ended March 31	
($ thousands)	**2022**	2021
Cash flows from operating activities	**$ 198,974**	$ 120,980
Change in non-cash working capital	**77,340**	34,185
Additions to exploration and evaluation assets	**(3,559)**	(216)
Additions to oil and gas properties	**(150,263)**	(83,372)
Payments on lease obligations	**(1,174)**	(1,082)
Free cash flow	**$ 121,318**	$ 70,495

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 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, cash and trade and other receivables. 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.

The following table summarizes our calculation of net debt.

($ thousands)		**March 31, 2022**		December 31, 2021
Credit facilities	**$**	**425,675**	$	505,171
Unamortized debt issuance costs - Credit facilities [1]		**1,183**		1,343
Long-term notes		**863,180**		874,527
Unamortized debt issuance costs - Long-term notes [1]		**10,700**		11,393
Trade and other payables		**257,683**		190,692
Trade and other receivables		**(282,741)**		(173,409)
Net debt	**$**	**1,275,680**	$	1,409,717

(1) Unamortized debt issuance costs were obtained from Note 6 Credit Facilities and Note 7 Long-term Notes from the Consolidated Financial Statements for the three months ended March 31, 2022.

Adjusted funds flow

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

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

	Three Months Ended March 31			
($ thousands)		**2022**		2021
Cash flow from operating activities	**$**	**198,974**	$	120,980
Change in non-cash working capital		**77,340**		34,185
Asset retirement obligations settled		**3,293**		1,417
Adjusted funds flow	**$**	**279,607**	$	156,582

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 months ended March 31, 2022. 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. All production from our Peavine asset is 100% Heavy Oil.

	Three Months Ended March 31, 2022				
	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	11,587	5	29	11,125	13,475
Lloydminster	10,495	15	—	1,787	10,808
Peavine	3,154	—	—	—	3,154
Canada - Light					
Viking	—	15,694	188	11,894	17,865
Duvernay	—	992	789	2,343	2,172
Remaining Properties	—	867	929	24,694	5,911
United States					
Eagle Ford	—	16,492	5,701	31,731	27,482
Total	25,236	34,065	7,636	83,574	80,867

This presentation discloses drilling inventory and potential drilling locations. Drilling inventory and drilling locations refers to Baytex's proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves. Unbooked locations are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. Of the 200 or more potential drilling locations identified in the Clearwater, as at December 31, 2021, 4 are proved locations, 5 are probable locations and the remainder are unbooked locations.

Baytex Energy Corp.

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

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

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