BAYTEX ANNOUNCES THIRD QUARTER 2022 RESULTS AND CONTINUED STRONG CLEARWATER DRILLING RESULTS

CALGARY, ALBERTA (November 3, 2022) - Baytex Energy Corp. ("Baytex")(TSX: BTE) reports its operating and financial results for the three and nine months ended September 30, 2022 (all amounts are in Canadian dollars unless otherwise noted).

"We continue to deliver on our commitments with a much-improved balance sheet (0.9x net debt to trailing 12 month EBITDA ratio), substantial free cash flow generation ($478 million through nine months) and a shareholder return framework that is driving real value for our shareholders (3.8% of shares repurchased to-date). We are building operational momentum as we approach 2023 with current Clearwater production of 10,000 bbl/d driving an expected corporate exit rate production of 87,000 to 88,000 boe/d. Our first four Clearwater wells this quarter generated 30 day initial production rates of 1,100 bbl/d per well and we have initiated down-spacing (moving to 5 wells per section) which offers a potential 20% increase in our future Peavine Clearwater drilling inventory," commented Ed LaFehr, President and Chief Executive Officer.

Highlights

- Generated production of 83,194 boe/d (84% oil and NGL) in Q3/2022, a 4% increase over Q3/2021. Production in October increased to over 87,000 boe/d.
- Delivered adjusted funds flow(1) of $284 million ($0.51 per basic share) in Q3/2022, a 43% increase compared to $198 million ($0.35 per basic share) in Q3/2021.
- Generated free cash flow(2) of $112 million ($0.20 per basic share) in Q3/2022, an 11% increase compared to $101 million ($0.18 per basic share) in Q3/2021.
- Reported cash flows from operating activities of $310 million ($0.56 per basic share) in Q3/2022, a 73% increase compared to $179 million ($0.32 per basic share) in Q3/2021.
- Reduced net debt(1) by 21% to $1.1 billion, from $1.4 billion at year-end 2021.
- Repurchased 21.6 million common shares year-to-date, representing 3.8% of our shares outstanding, at an average price of $6.53 per share.
- Divested of non-core natural gas assets in west central Alberta for net proceeds of $26 million. Production associated with the divestiture was approximately 600 boe/d.
- Generated production from our Clearwater play at Peavine of 8,191 bbl/d in Q3/2022. Production during the month of October averaged 10,000 bbl/d from 24 producing wells.

CEO Transition

As previously announced, the Board of Directors appointed Mr. Eric Greager to the position of President and Chief Executive Officer and as a Director effective November 4, 2022. Mr. Greager succeeds Mr. LaFehr who announced his intention to retire earlier this year. In keeping with this transition, Mr. LaFehr has also stepped down from the Board of Directors, he will remain in an advisory capacity until January 2023.

2022 Outlook

We remain intensely focused on maintaining capital discipline and driving meaningful free cash flow in our business. We continue to execute our 2022 plan and anticipate full-year production of approximately 84,000 boe/d (mid-point of previous guidance range of 83,000 to 85,000 boe/d) with a targeted exit rate of 87,000 to 88,000 boe/d. Based on the forward strip for the balance of 2022(3) we expect to generate approximately $650 million of free cash flow this year.

(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) Q4/2022 pricing assumptions: WTI - US$86/bbl; WCS differential - US$26/bbl; MSW differential – US$2/bbl, NYMEX Gas - US$6.60/mcf; AECO Gas - $5.25/mcf and Exchange Rate (CAD/USD) - 1.36.

2022 Outlook (continued)

We now anticipate full-year 2022 exploration and development expenditures of approximately $515 million, up 3% from our previously targeted $500 million (representing the high end of our prior guidance range of $450 to $500 million). The incremental capital largely reflects the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. operations and further level loading of activity through year-end to maintain the efficiency of our operations.

We have increased our general and administrative expense by 12% largely to reflect the impacts of inflation and expanded staffing costs associated with our higher pace of activity and strong performance. We have also fine-tuned our interest expense guidance to reflect higher interest rates on our credit facilities and the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt.

The following table highlights our 2022 annual guidance.

	2022 Guidance (1)	2022 Revised Guidance
Exploration and development expenditures	$450 - $500 million	~ $515 million
Production (boe/d)	83,000 - 85,000	~ 84,000 boe/d
Expenses:		
Average royalty rate (2)	21.0% - 22.0%	no change
Operating (3)	$13.75 - $14.25/boe	no change
Transportation (3)	$1.50 - $1.60/boe	no change
General and administrative (3)	$43 million ($1.40/boe)	$48 million ($1.57/boe)
Interest (3)	$75 million ($2.45/boe)	$79 million ($2.58/boe)
Leasing expenditures	$3 million	no change
Asset retirement obligations	$20 million	no change

Our 2023 capital budget is expected to be released in early December following approval by our Board of Directors.

Shareholder Returns

Our improved financial position enabled us to implement the second phase of our enhanced shareholder return framework in May, allocating 25% of annual free cash flow to a share buyback program with 75% of free cash flow allocated to debt reduction.

During the third quarter, we repurchased 12.6 million common shares for $79 million, representing 2.2% of our shares outstanding, at an average price of $6.25 per share. Year-to-date, we have repurchased 21.6 million common shares for $141 million, representing 3.8% of our shares outstanding, at an average price of $6.53 per share.

As of September 30, 2022, our net debt(4) totaled $1.1 billion, representing a net debt to EBITDA(5) ratio (trailing twelve months) of 0.9x. Our net debt at quarter-end was largely unchanged from Q2/2022 due to our share buyback program and the impact of a strengthening U.S. dollar, relative to the Canadian dollar, on our U.S. dollar denominated debt. Based on current commodity prices and forecast free cash flow for the fourth quarter, we expect to exit 2022 with net debt of under $1.0 billion. In addition, we expect to reach a net debt level of $800 million by mid-2023(6), at which time, we anticipate increasing direct shareholder returns to 50% of our free cash flow and accelerating our share buyback program.

We have also established an ultimate net debt target for the company of $400 million, which represents an expected net debt to EBITDA ratio of 1.0x at a US$45 WTI price. We feel this level of net debt will provide us with full flexibility to run our business through the commodity price cycles and generate meaningful returns for our shareholders. At current commodity prices, we expect to achieve this net debt level in 2024, at which point we intend to increase direct shareholder returns to 75% of our free cash flow.

(1) As announced on July 27, 2022.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Calculated as operating, transportation, general and administrative or cash interest expense divided by barrels of oil equivalent production volume for the applicable period.
(4) Capital management measure. Refer to the Specified Financial Measures in this press release for further information.
(5) Calculated in accordance with the Credit Facilities Agreement.
(6) 2023 pricing assumptions: WTI - US$79/bbl; WCS differential - US$23/bbl; MSW differential – US$3/bbl, NYMEX Gas - US$5.20/mcf; AECO Gas - $4.65/mcf and Exchange Rate (CAD/USD) - 1.36.

	Three Months Ended			Nine Months Ended	
	September 30, 2022	June 30, 2022	September 30, 2021	**September 30, 2022**	September 30, 2021
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 712,065**	$ 854,169	$ 488,736	**$ 2,240,059**	$ 1,315,792
Adjusted funds flow (1)	**284,288**	345,704	198,397	**909,599**	530,862
Per share – basic	**0.51**	0.61	0.35	**1.62**	0.94
Per share – diluted	**0.51**	0.60	0.35	**1.60**	0.93
Free cash flow (2)	**111,568**	245,316	101,215	**478,202**	284,196
Per share – basic	**0.20**	0.43	0.18	**0.85**	0.50
Per share – diluted	**0.20**	0.43	0.18	**0.84**	0.50
Cash flows from operating activities	**310,423**	360,034	178,961	**869,431**	471,817
Per share – basic	**0.56**	0.63	0.32	**1.55**	0.84
Per share – diluted	**0.56**	0.63	0.31	**1.53**	0.83
Net income	**264,968**	180,972	32,713	**502,798**	1,050,361
Per share – basic	**0.48**	0.32	0.06	**0.89**	1.86
Per share – diluted	**0.47**	0.32	0.06	**0.89**	1.84
Capital Expenditures					
Exploration and development expenditures	**$ 167,453**	$ 96,633	$ 94,235	**$ 417,908**	$ 239,308
Acquisitions and divestitures	**(25,460)**	194	(612)	**(25,234)**	(833)
Total oil and natural gas capital expenditures	**$ 141,993**	$ 96,827	$ 93,623	**$ 392,674**	$ 238,475
Net Debt					
Credit facilities	**$ 450,051**	$ 496,917	$ 546,803	**$ 450,051**	$ 546,803
Long-term notes	**648,207**	643,600	1,000,171	**648,207**	1,000,171
Long-term debt	**1,098,258**	1,140,517	1,546,974	**1,098,258**	1,546,974
Working capital	**15,301**	(17,220)	17,684	**15,301**	17,684
Net debt (1)	**$ 1,113,559**	$ 1,123,297	$ 1,564,658	**$ 1,113,559**	$ 1,564,658
Shares Outstanding - basic (thousands)					
Weighted average	**553,409**	566,997	564,211	**561,931**	563,492
End of period	**547,615**	560,139	564,213	**547,615**	564,213
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 91.56**	$ 108.41	$ 70.56	**$ 98.09**	$ 64.82
MEH oil (US$/bbl)	**96.15**	112.41	71.64	**101.76**	66.05
MEH oil differential to WTI (US$/bbl)	**4.59**	4.00	1.08	**3.67**	1.23
Edmonton par ($/bbl)	**116.79**	137.79	83.78	**123.41**	75.88
Edmonton par differential to WTI (US$/bbl)	**(2.13)**	(0.47)	(4.07)	**(1.89)**	(4.19)
WCS heavy oil ($/bbl)	**93.62**	122.05	71.81	**105.65**	65.47
WCS differential to WTI (US$/bbl)	**(19.87)**	(12.80)	(13.57)	**(15.74)**	(12.51)
Natural gas					
NYMEX (US$/mmbtu)	**$ 8.20**	$ 7.17	$ 4.01	**$ 6.77**	$ 3.18
AECO ($/mcf)	**5.81**	6.27	3.54	**5.56**	3.11
CAD/USD average exchange rate	**1.3059**	1.2766	1.2601	**1.2829**	1.2515

	Three Months Ended			Nine Months Ended	
	September 30, 2022	June 30, 2022	September 30, 2021	**September 30, 2022**	September 30, 2021
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**33,247**	33,007	35,614	**33,437**	36,060
Heavy oil (bbl/d)	**29,244**	28,586	21,996	**27,703**	21,752
NGL (bbl/d)	**7,536**	7,468	7,174	**7,547**	6,995
Total liquids (bbl/d)	**70,027**	69,061	64,784	**68,686**	64,807
Natural gas (mcf/d)	**79,003**	84,169	90,528	**82,232**	90,812
Oil equivalent (boe/d @ 6:1) (3)	**83,194**	83,090	79,872	**82,392**	79,942
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 671,120**	$ 797,274	$ 469,155	**$ 2,100,779**	$ 1,259,124
Royalties	**(146,994)**	(171,559)	(90,523)	**(441,273)**	(239,004)
Operating expense	**(110,139)**	(107,426)	(84,196)	**(318,331)**	(247,645)
Transportation expense	**(12,771)**	(11,758)	(7,818)	**(33,744)**	(24,092)
Operating netback (2)	**$ 401,216**	**$ 506,531**	**$ 286,618**	**$ 1,307,431**	**$ 748,383**
General and administrative	**(12,003)**	(11,640)	(9,980)	**(35,325)**	(29,323)
Cash financing and interest	**(19,774)**	(20,474)	(22,793)	**(60,675)**	(70,750)
Realized financial derivatives loss	**(76,408)**	(124,042)	(53,905)	**(284,816)**	(113,697)
Other (4)	**(8,743)**	(4,671)	(1,543)	**(17,016)**	(3,751)
Adjusted funds flow (1)	**$ 284,288**	**$ 345,704**	**$ 198,397**	**$ 909,599**	**$ 530,862**
Netback (per boe) (5)					
Total sales, net of blending and other expense (2)	**$ 87.68**	$ 105.44	$ 63.85	**$ 93.40**	$ 57.69
Royalties	**(19.21)**	(22.69)	(12.32)	**(19.62)**	(10.95)
Operating expense	**(14.39)**	(14.21)	(11.46)	**(14.15)**	(11.35)
Transportation expense	**(1.67)**	(1.56)	(1.06)	**(1.50)**	(1.10)
Operating netback (2)	**$ 52.41**	**$ 66.98**	**$ 39.01**	**$ 58.13**	**$ 34.29**
General and administrative	**(1.57)**	(1.54)	(1.36)	**(1.57)**	(1.34)
Cash financing and interest	**(2.58)**	(2.71)	(3.10)	**(2.70)**	(3.24)
Realized financial derivatives loss	**(9.98)**	(16.41)	(7.34)	**(12.66)**	(5.21)
Other (4)	**(1.14)**	(0.60)	(0.21)	**(0.76)**	(0.18)
Adjusted funds flow (1)	**$ 37.14**	**$ 45.72**	**$ 27.00**	**$ 40.44**	**$ 24.32**

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 Q3/2022 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.

Q3/2022 Results

During the third quarter, we delivered strong operating and financial results which has set the stage for continued momentum as we approach 2023. In addition, we advanced our exciting Clearwater play at Peavine with initial results from our H2/2022 drilling program delivering among the best wells drilled to date in the play.

Production during the third quarter averaged 83,194 boe/d (84% oil and NGL) as compared to 83,090 boe/d (83% oil and NGL) in Q2/2022. Production in October increased to over 87,000 boe/d, in line with our targeted exit production rate of 87,000 to 88,000 boe/d. Exploration and development expenditures totaled $167 million in Q3/2022 and we participated in the drilling of 86 (72.0 net) wells.

During the quarter, we delivered adjusted funds flow(1) of $284 million ($0.51 per basic share) and net income of $265 million ($0.48 per basic share). We generated free cash flow(2) of $112 million ($0.20 per basic share) which brings our year-to-date free cash flow to $478 million ($0.85 per basic share).

Operating Results

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 27,391 boe/d (82% oil and NGL) during Q3/2022 and generated an operating netback(2) of $140 million. We invested $50 million on exploration and development in the Eagle Ford during the quarter and brought 19 (4.1 net) wells onstream. We expect to bring approximately 18 net wells onstream in 2022.

Production in the Viking averaged 16,019 boe/d (88% oil and NGL) during Q3/2022 and generated an operating netback of $116 million. We invested $62 million on exploration and development in the Viking during the quarter and brought 42 (40.5 net) wells onstream. We expect to bring approximately 130 net wells onstream in 2022.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster (excluding Clearwater development) produced a combined 23,377 boe/d (90% oil and NGL) during Q3/2022 and generated an operating netback of $80 million. We invested $31 million on exploration and development during the quarter and brought onstream 2 net Bluesky wells at Peace River and 2.6 net wells at Lloydminster. In 2022, we will drill approximately 9 net Bluesky wells at Peace River and 31 net wells at Lloydminster.

Peace River Clearwater

Production in the Clearwater averaged 8,191 boe/d (100% oil) during Q3/2022 and generated an operating netback of $37 million. Production during the month of October averaged approximately 10,000 bbl/d from 24 producing wells.

Our second half drilling program kicked off in July and will include the drilling of 13 Clearwater wells, including 12 wells at Peavine and one well at Seal that follows up a successful exploration well from 2021. The first four wells from the H2/2022 drilling program generated average 30-day initial production rates of 1,100 bbl/d per well. Initial well performance continues to outperform type curve assumptions and we now hold 13 of the top 15 initial rate wells drilled across the play.

We continue to optimize planned development for our Peavine lands, which now includes a combination of traditional multi-lateral wells (eight one-mile long laterals) and extended reach horizontal ("ERH") multi-lateral wells (four two-mile long laterals). The ERH multi-lateral wells are utilized to provide appropriate set-backs to residents and environmentally sensitive areas and were among the first of their type to be drilled in western Canada.

Following further detailed reservoir and economic analysis of the Peavine Clearwater, our most recent wells were drilled at 40 metre inter-lateral spacing (5 wells per section) whereas our initial wells were drilled at 50 metre inter-lateral spacing (4 wells per section). At this tighter spacing, we could potentially see a 20% increase in our prospective drilling inventory yielding meaningfully improved resource recovery and value.

The Clearwater generates among the strongest economics within our portfolio with payouts of less than five months at US$80 WTI 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 250 locations with production increasing to approximately 15,000 bbl/d. When combined with our legacy acreage position in northwest Alberta, we estimate that over 125 sections of our lands 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 3,405 boe/d (84% oil and NGL) during Q3/2022.

The Pembina Duvernay shale is an early stage, high operating netback light oil resource play. During the first quarter, we drilled a three-well pad on the northern edge of our land base that was brought on production in June/July. Performance of the three-wells has tracked to type well forecast for that region, generating an average 90-day initial production rate of approximately 700 boe/d per well (86% crude oil and NGL). The three wells, each drilled to a vertical depth of 2,400 metres with a horizontal lateral of 1.85 miles, were drilled and completed for $8.3 million per well.

As we progress our understanding of the reservoir and gain confidence in capital execution and well performance, we believe the Pembina Duvernay shale has the potential to generate competitive returns within our portfolio, with payouts of 13 to 15 months at US$80 WTI. For 2023, we are in the planning stages of a four-well program to further progress our development. Across our Pembina acreage, we hold 200 sections of contiguous 100% working interest lands.

Financial Liquidity

Our net debt[1], which includes our credit facilities, long-term notes and working capital, totaled $1.11 billion at September 30, 2022, down from $1.41 billion at December 31, 2021.

During the third quarter, we repurchased and cancelled US$26.8 million principal amount of 8.75% long-term notes due 2027.

As of September 30, 2022, we had $714 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $699 million.

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 fourth quarter of 2022, we have 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 50% of our expected net Canadian light oil exposure at US$3.73/bbl and WCS differential hedges on approximately 60% 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$78.36/bbl with upside participation to US$96.11/bbl

A complete listing of our financial derivative contracts can be found in Note 16 to our Q3/2022 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 and nine months ended September 30, 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, November 4, 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 https://services.choruscall.ca/links/baytex20221104.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 expected exit rate production of 87,000 to 88,000 boe/d; the potential for a 20% increase in future Clearwater drilling inventory as a result of down-spacing to 5 wells per section; we are focused on maintaining capital discipline and driving meaningful free cash flow; that we expect to generate $650 million of free cash flow in 2022; our revised 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; that our 2023 capital budget is expected to be released in early December; that we will continue allocating 25% of free cash flow to a share buyback program and 75% to debt reduction; that we expect our net debt will be under $1 billion at year-end 2022 and that our net debt will be $800 million by mid-2023 at which point we will increase direct shareholder returns to 50% of free cash flow and accelerate our share buyback program; our expected 1.0x net debt to EBITDA ratio at a US$45 WTI price when we reach our $400 million net debt target, which we expect to reach in 2024 at which point we will consider steps to further enhance shareholder returns; in 2022 that we expect to: bring on production 18 net wells in the Eagle Ford and 130 in the Viking; that we expect to drill 9 net Bluesky wells at Peace River and 31 net wells at Lloydminster in 2022; we plan to drill 13 additional Clearwater wells in H2/2022; that we could see a 20% increase in our prospective drilling inventory in the Clearwater due to down spacing which could yield meaningfully improved resource recovery and value; that the Clearwater generates among the strongest economics in our portfolio with payouts of less than five months at US $80 WTI and has the ability to grow organically while enhancing our free cash flow profile; to date we have de-risked 50 sections of Peavine lands which hold the potential for 250 locations, with production increasing to 15,000 bbl/d; we have over 125 sections that are highly prospective for Clearwater development; that we believe the Pembina Duvernay shale has the potential to generate competitive returns within our portfolio, with payouts of 13 to 15 months at US$80 WTI and for 2023, we are in the planning stages of a four-well program to further progress our development; 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 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; 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 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 September 30		Nine Months Ended September 30	
($ thousands)	**2022**	2021	**2022**	2021
Petroleum and natural gas sales	**$ 712,065**	$ 488,736	**$ 2,240,059**	$ 1,315,792
Blending and other expense	**(40,945)**	(19,581)	**(139,280)**	(56,668)
Total sales, net of blending and other expense	**671,120**	469,155	**2,100,779**	1,259,124
Royalties	**(146,994)**	(90,523)	**(441,273)**	(239,004)
Operating expense	**(110,139)**	(84,196)	**(318,331)**	(247,645)
Transportation expense	**(12,771)**	(7,818)	**(33,744)**	(24,092)
Operating netback	**$ 401,216**	$ 286,618	**$ 1,307,431**	$ 748,383

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 September 30		Nine Months Ended September 30	
($ thousands)	**2022**	2021	**2022**	2021
Cash flows from operating activities	**$ 310,423**	$ 178,961	**$ 869,431**	$ 471,817
Change in non-cash working capital	**(30,734)**	17,631	**29,560**	54,830
Additions to exploration and evaluation assets	**—**	(89)	**(5,897)**	(733)
Additions to oil and gas properties	**(167,453)**	(94,146)	**(412,011)**	(238,575)
Payments on lease obligations	**(668)**	(1,142)	**(2,881)**	(3,143)
Free cash flow	**$ 111,568**	$ 101,215	**$ 478,202**	$ 284,196

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)	**September 30, 2022**	December 31, 2021
Credit facilities	**$ 447,475**	$ 505,171
Unamortized debt issuance costs - Credit facilities (1)	**2,576**	1,343
Long-term notes	**639,679**	874,527
Unamortized debt issuance costs - Long-term notes (1)	**8,528**	11,393
Trade and other payables	**271,400**	190,692
Cash	**(4,410)**	—
Trade and other receivables	**(251,689)**	(173,409)
Net debt	**$ 1,113,559**	$ 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 and nine months ended September 30, 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 September 30		Nine Months Ended September 30	
($ thousands)	**2022**	2021	**2022**	2021
Cash flow from operating activities	**$ 310,423**	$ 178,961	**$ 869,431**	$ 471,817
Change in non-cash working capital	**(30,734)**	17,631	**29,560**	54,830
Asset retirement obligations settled	**4,599**	1,805	**10,608**	4,215
Adjusted funds flow	**$ 284,288**	$ 198,397	**$ 909,599**	$ 530,862

Advisory Regarding Oil and Gas Information

Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

References herein to average 30-day initial production rates and other short-term production rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating aggregate production for us or the assets for which such rates are provided. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, we caution that the test results should be considered to be preliminary.

Throughout this press release, "oil and NGL" refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and nine months ended September 30, 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 September 30, 2022					Nine Months Ended September 30, 2022				
	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	10,282	13	41	12,026	12,340	10,691	9	33	11,877	12,713
Lloydminster	10,770	4	—	1,575	11,037	10,773	9	—	1,696	11,065
Peavine	8,191	—	—	—	8,191	6,240	—	—	—	6,240
Canada - Light										
Viking	—	13,908	191	11,516	16,019	—	14,562	188	12,203	16,783
Duvernay	—	1,894	959	3,305	3,405	—	1,233	790	2,555	2,449
Remaining Properties	—	690	682	20,638	4,811	—	769	864	22,972	5,461
United States										
Eagle Ford	—	16,738	5,663	29,943	27,391	—	16,855	5,671	30,929	27,681
Total	29,244	33,247	7,536	79,003	83,194	27,703	33,437	7,546	82,232	82,392

This press release 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 250 or more potential drilling locations currently 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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