Baytex Announces Fourth Quarter and Full Year 2023 Financial and Operating Results and Year End Reserves

Calgary, Alberta--(Newsfile Corp. - February 28, 2024) - Baytex Energy Corp. (TSX: BTE) (NYSE: BTE) ("Baytex") reports its operating and financial results for the three months and year ended December 31, 2023 (all amounts are in Canadian dollars unless otherwise noted).

"Our 2023 results demonstrate the strength of our oil-weighted portfolio. The strategic acquisition of Ranger added quality scale in the Eagle Ford and reinforced the resiliency and sustainability of our business. In 2023, we increased production per share by 16% and fourth quarter production exceeded guidance with continued strong results in the Eagle Ford and Peavine. During 2023, we increased shareholder returns to 50% of free cash flow, increased our share buyback program and introduced a quarterly dividend. We are well-capitalized and remain committed to creating long-term value and increasing shareholder returns," commented Eric T. Greager, President and Chief Executive Officer.

2023 Highlights

- Completed the acquisition of Ranger Oil Corporation ("Ranger") on June 20, 2023.
- Reported cash flows from operating activities of $474 million ($0.57 per basic share) in Q4/2023 and $1,296 million ($1.84 per basic share) for 2023.
- Delivered adjusted funds flow(1) of $502 million ($0.60 per basic share) in Q4/2023 and $1,594 million ($2.26 per basic share) for 2023.
- Generated free cash flow(2) of $291 million ($0.35 per basic share) in Q4/2023 and $544 million ($0.77 per basic share) for 2023.
- Increased direct shareholder returns to 50% of free cash flow(2) and returned $260 million to shareholders. Repurchased 40.5 million common shares for $222 million, representing 4.7% of our shares outstanding, and declared two quarterly dividends of $0.0225 per share, totaling $38 million in 2023.
- Increased production per basic share by 16% in 2023, compared to 2022. Production for the full-year 2023 averaged 122,154 boe/d (85% oil and NGL), compared to 83,519 boe/d in 2022 (84% oil and NGL).
- Production in Q4/2023 averaged 160,373 boe/d (83% oil and NGL), exceeding guidance of 158,000 to 160,000 boe/d, and up 6% from Q3/2023 on exploration and development expenditures of $199 million, 10% below guidance.
- Divested of our Viking assets at Forgan and Plato in southwest Saskatchewan (production of approximately 4,000 boe/d) for proceeds of $160 million, including closing adjustments.
- Improved our cash cost structure (operating, transportation, and general & administrative expenses) in Q4/2023 by 12% on a boe basis, as compared to Q4/2022.
- Maintained balance sheet strength with a total debt to EBITDA(3) ratio(2) of 1.1x. During the fourth quarter we reduced our net debt(1) by 10% ($290 million).
- Reduced our GHG emissions intensity in 2023 by 9% from 2022 levels and achieved our 65% reduction target, relative to our 2018 baseline, two years early.
- Proved developed producing reserves increased by 49%, from 124 MMboe to 185 MMboe(4). Proved reserves increased by 55%, from 264 MMboe to 410 MMboe(4). Proved plus probable reserves increased by 51%, from 438 MMboe to 663 MMboe(4).
- At year-end 2023, the present value of our 2P reserves, discounted at 10% before tax, is estimated to be $7.8 billion ($5.9 billion at year-end 2022).

We recorded a non-cash impairment of $834 million on our legacy non-operated Eagle Ford and retained Viking assets as the carrying value of our oil and gas properties exceeded their recoverable amounts. This resulted in a net loss of $626 million ($0.75 per basic share) in Q4/2023 and $233 million ($0.33 per basic share) in 2023.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com
(4) Baytex's year-end 2023 reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent qualified reserves evaluator, in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101").

	Three Months Ended			Twelve Months Ended	
	December 31, 2023	September 30, 2023	December 31, 2022	**December 31, 2023**	December 31, 2022
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 1,065,515**	$ 1,163,010	$ 648,986	**$ 3,382,621**	$ 2,889,045
Adjusted funds flow (1)	**502,148**	581,623	255,552	**1,594,350**	1,165,151
Per share - basic	**0.60**	0.68	0.47	**2.26**	2.09
Per share - diluted	**0.60**	0.68	0.46	**2.26**	2.07
Free cash flow (2)	**290,785**	158,440	143,324	**543,620**	621,526
Per share - basic	**0.35**	0.19	0.26	**0.77**	1.11
Per share - diluted	**0.35**	0.18	0.26	**0.77**	1.10
Cash flows from operating activities	**474,452**	444,033	303,441	**1,295,731**	1,172,872
Per share - basic	**0.57**	0.52	0.56	**1.84**	2.10
Per share - diluted	**0.57**	0.52	0.55	**1.84**	2.08
Net income (loss)	**(625,830)**	127,430	352,807	**(233,356)**	855,605
Per share - basic	**(0.75)**	0.15	0.65	**(0.33)**	1.53
Per share - diluted	**(0.75)**	0.15	0.64	**(0.33)**	1.52

Dividends declared	**18,381**	19,138	-	**37,519**	-
Per share	**0.0225**	0.0225	-	**0.045**	-
Capital Expenditures					
Exploration and development expenditures	**$ 199,214**	$ 409,191	$ 103,634	**$ 1,012,787**	$ 521,542
Acquisitions and (divestitures)	**(125,822)**	4,051	937	**(121,342)**	(24,297)
Total oil and natural gas capital expenditures	**$ 73,392**	$ 413,242	$ 104,571	**$ 891,445**	$ 497,245
Net Debt					
Credit facilities	**$ 864,736**	$ 1,046,756	$ 385,394	**$ 864,736**	$ 385,394
Long-term notes	**1,597,475**	1,637,640	554,597	**1,597,475**	554,597
Total debt (3)	**2,462,211**	2,684,396	939,991	**2,462,211**	939,991
Working capital deficiency (2)	**72,076**	139,952	47,455	**72,076**	47,455
Net debt (1)	**$ 2,534,287**	$ 2,824,348	$ 987,446	**$ 2,534,287**	$ 987,446
Shares Outstanding - basic (thousands)					
Weighted average	**831,063**	855,300	546,279	**704,896**	557,986
End of period	**821,681**	845,360	544,930	**821,681**	544,930
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 78.32**	$ 82.26	$ 82.64	**$ 77.62**	$ 94.23
MEH oil (US$/bbl)	**80.62**	84.10	85.88	**79.29**	97.79
MEH oil differential to WTI (US$/bbl)	**2.30**	1.84	3.24	**1.67**	3.57
Edmonton par ($/bbl)	**99.72**	107.93	109.57	**100.46**	119.95
Edmonton par differential to WTI (US$/bbl)	**(5.10)**	(1.78)	(1.94)	**(3.18)**	(2.07)
WCS heavy oil ($/bbl)	**76.86**	93.02	77.37	**79.58**	98.94
WCS differential to WTI (US$/bbl)	**(21.88)**	(12.89)	(25.65)	**(18.65)**	(18.21)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.88**	$ 2.55	$ 6.26	**$ 2.74**	$ 6.64
AECO ($/mcf)	**2.66**	2.39	5.58	**2.93**	5.56
CAD/USD average exchange rate	**1.3619**	1.3410	1.3577	**1.3495**	1.3016

Notes:

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

	Three Months Ended			**Twelve Months Ended**	
	December 31, 2023	September 30, 2023	December 31, 2022	**December 31, 2023**	December 31, 2022
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**70,124**	75,763	32,105	**53,389**	33,101
Heavy oil (bbl/d)	**39,569**	35,204	32,819	**35,460**	28,993
NGL (bbl/d)	**23,160**	18,004	7,661	**14,304**	7,575
Total liquids (bbl/d)	**132,853**	128,971	72,585	**103,153**	69,669
Natural gas (mcf/d)	**165,121**	129,780	85,679	**114,010**	83,101
Oil equivalent (boe/d @ 6:1) (1)	**160,373**	150,600	86,864	**122,154**	83,519
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 1,003,219**	$ 1,113,180	$ 598,812	**$ 3,157,819**	$ 2,699,591
Royalties	**(228,570)**	(240,049)	(121,691)	**(669,792)**	(562,964)
Operating expense	**(164,873)**	(174,119)	(104,335)	**(570,839)**	(422,666)
Transportation expense	**(29,744)**	(27,983)	(14,817)	**(89,306)**	(48,561)
Operating netback (2)	**$ 580,032**	$ 671,029	$ 357,969	**$ 1,827,882**	$ 1,665,400
General and administrative	**(22,280)**	(20,536)	(14,945)	**(69,789)**	(50,270)
Cash financing and interest	**(56,698)**	(56,495)	(19,711)	**(159,823)**	(80,386)
Realized financial derivatives gain (loss)	**12,377**	2,055	(49,665)	**36,212**	(334,481)
Other (3)	**(11,283)**	(14,430)	(18,096)	**(40,132)**	(35,112)
Adjusted funds flow (4)	**$ 502,148**	$ 581,623	$ 255,552	**$ 1,594,350**	$ 1,165,151
Netback per boe (2)					
Total sales, net of blending and other expense (2)	**$ 68.00**	$ 80.34	$ 74.93	**$ 70.82**	$ 88.56
Royalties (5)	**(15.49)**	(17.33)	(15.23)	**(15.02)**	(18.47)
Operating expense (5)	**(11.17)**	(12.57)	(13.06)	**(12.80)**	(13.86)
Transportation expense (5)	**(2.02)**	(2.02)	(1.85)	**(2.00)**	(1.59)
Operating netback (2)	**$ 39.32**	$ 48.42	$ 44.79	**$ 41.00**	$ 54.64
General and administrative (5)	**(1.51)**	(1.48)	(1.87)	**(1.57)**	(1.65)
Cash financing and interest (5)	**(3.84)**	(4.08)	(2.47)	**(3.58)**	(2.64)
Realized financial derivatives gain (loss) (5)	**0.84**	0.15	(6.21)	**0.81**	(10.97)
Other (3)	**(0.78)**	(1.03)	(2.26)	**(0.90)**	(1.16)
Adjusted funds flow (4)	**$ 34.03**	$ 41.98	$ 31.98	**$ 35.76**	$ 38.22

Notes:

(1) 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.
(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) 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 2023 MD&A for further information on these amounts.
(4) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(5) Calculated as royalties, operating, transportation expense, general and administrative expense, cash interest expense or realized financial derivatives gain (loss) divided by

barrels of oil equivalent production volume for the applicable period.

Strategy and 2024 Outlook

We are a well-capitalized, North American oil-weighted producer with 60% of our producing assets located in the Eagle Ford with the balance in western Canada. We are committed to a disciplined, returns-based capital allocation philosophy to drive increased per-share returns. The key elements of our business strategy include:

- Disciplined Capital Allocation. Each of our core assets has 10 or more years of development inventory at our planned pace of development. This provides us the ability to efficiently allocate capital and respond to changes in regional commodity prices and other economic factors. Over our five-year outlook (2024 to 2028), we expect to generate annual production growth of 1% to 4%, with production reaching approximately 170,000 boe/d in 2028.

- Free Cash Flow(1). Our commitment to disciplined capital allocation across our portfolio is expected to generate meaningful free cash flow(1). We intend to allocate 50% of free cash flow(1) to debt repayment and 50% to shareholder returns, which includes a combination of share buybacks and a quarterly dividend.

- Financial Strength. We are committed to maintaining a strong balance sheet and significant financial liquidity. We are in a strong financial position with a total debt to EBITDA(2) ratio(1) of 1.1x. Upon reaching a total debt(2) target of $1.5 billion, we intend to direct 75% of free cash flow(1) to shareholder returns.

In January, extremely cold temperatures across North America, followed by heavy rainfall in Texas, led to production disruptions. Our production has been restored, however, first quarter production will be approximately 2,000 boe/d lower than our budget expectation. Despite this, our 2024 guidance remains unchanged with exploration and development expenditures of $1.2 to $1.3 billion and production of 150,000 to 156,000 boe/d. In 2024, we intend to progress the Pembina Duvernay, further delineate our Clearwater and Mannville heavy oil positions, and deliver strong drilling and completion performance in the Eagle Ford and Viking.

Based on the forward strip(3), we expect to generate approximately $575 million of free cash flow(1) in 2024. Our capital program is weighted to the first and third quarters and as a result, we expect to generate a significant amount of our 2024 free cash flow(1) during the second and fourth quarters.

2023 Results

On June 20, 2023, we closed the acquisition of Ranger, adding quality scale in the Eagle Ford and reinforcing a resilient and sustainable business. In conjunction with closing, we increased direct shareholder returns to 50% of free cash flow(1), which allowed us to increase the value of our share buyback program and introduce a dividend. The remainder of our free cash flow(1) was allocated to debt reduction.

In 2023, we returned $260 million to shareholders through our share buyback program and dividend. Our normal course issuer bid allows for the purchase of up to 68.4 million common shares during the 12-month period ending June 28, 2024. Through December 31, 2023, we repurchased 40.5 million common shares for $222 million, representing 4.7% of our shares outstanding, at an average price of $5.48 per share. In addition, we declared two quarterly dividends of $0.0225 per share, totaling $38 million.

We increased production per basic share by 16% in 2023, compared to 2022. Production in Q4/2023 averaged 160,373 boe/d (83% oil and NGL), exceeding our guidance for the quarter of 158,000 to 160,000 boe/d, and up 6% from 150,600 boe/d (85% oil and NGL) in Q3/2023. Production for the full-year 2023 averaged 122,154 boe/d, compared to 83,519 boe/d in 2022.

Exploration and development expenditures totaled $1,013 million in 2023 as compared to our annual guidance of $1,035 million. We participated in the drilling of 303 (254.0 net) wells in 2023. For the second half of 2023, exploration and development expenditures totaled $608 million, consistent with our plan following the Ranger acquisition.

Our business improved structurally through the Ranger acquisition with increased exposure to premium U.S. Gulf Coast pricing and improved margins. In Q4/2023, over 40% of our liquids production received WTI equivalent pricing and our realized light oil and condensate price in the Eagle Ford was $105.83/bbl, or US$77.60/bbl. In addition, we improved our cash cost structure (operating, transportation, general & administrative expenses) in Q4/2023 by 12% on a boe basis compared to Q4/2022.

(1) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(2) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.
(3) 2024 pricing assumptions: WTI - US$75/bbl; WCS differential - US$16/bbl; NYMEX Gas - US$2.25/MMbtu; and Exchange Rate (CAD/USD) - 1.35.

On December 11, 2023, we completed the divestiture of Viking assets at Forgan and Plato in southwest Saskatchewan for proceeds of $160 million, including closing adjustments. Proceeds from the sale were applied against our credit facilities. Production from the assets at the time of the sale was approximately 4,000 boe/d (100% light and medium crude oil). We incurred a non-cash loss of $144 million related to the sale.

During the fourth quarter we reduced our net debt(1) by 10% ($290 million) due to a combination of free cash flow generation, net proceeds from the Viking divestiture and the impact of a strengthening Canadian dollar, relative to the U.S. dollar, on our U.S.

dollar denominated debt. Our total debt[2] at December 31, 2023 was $2.5 billion and we have $588 million of undrawn capacity on our credit facilities.

We employ a disciplined commodity hedging program to help mitigate the volatility in revenue due to changes in commodity prices. In 2023, our hedging program generated realized financial derivatives gains of $36 million. For 2024, we have entered into hedges on approximately 40% of our net crude oil exposure utilizing two-way collars with an average floor price of US$60/bbl and an average ceiling price of US$96/bbl. A complete listing of our financial derivative contracts can be found in Note 18 to our 2023 financial statements.

At year-end 2023, we identified indicators of impairment on our legacy non-operated Eagle Ford and retained Viking assets. As a result, we recorded total non-cash impairments of $834 million in Q4/2023 as the carrying value of our oil and gas properties exceeded their recoverable amounts. This non-cash impairment resulted in a net loss of $626 million ($0.75 per basic share) in Q4/2023 and $233 million ($0.33 per basic share) in 2023.

Operations

The integration of the Ranger assets has progressed well. We continue to optimize base performance and remain focused on strong drilling and completion performance. For 2024, we are targeting an 8% improvement in our operated drilling and completion costs per completed lateral foot over 2023.

In the Eagle Ford, we continue to deliver strong results across the black oil, volatile oil, and condensate thermal maturity windows. In Q4/2023, 9 (8.9 net) operated wells were brought onstream, bringing the total operated wells on production since closing the Ranger acquisition to 22 (21.8 net) wells. The nine wells brought onstream during the fourth quarter generated an average 30-day initial production rate of approximately 1,600 boe/d (80% oil and NGL) per well. On our non-operated acreage, there were no new wells brought onstream during the fourth quarter.

In the Pembina Duvernay, we commenced drilling operations in January and to-date have drilled three of seven wells planned for 2024. Completion activities are scheduled to commence in May. We continue to advance our understanding of the reservoir and believe the asset offers significant economic inventory growth potential.

In our heavy oil business unit, our Clearwater production averaged 16,338 boe/d during the fourth quarter, up 48% from Q4/2022. At Peavine, we brought 31 (31.0 net) wells onstream during 2023 and initial well performance continues to outperform type curve assumptions. In 2024, we will see continued exploration across our heavy oil portfolio with up to 14 stratigraphic test wells planned.

Quarterly Dividend

The Board of Directors has declared a quarterly cash dividend of $0.0225 per share to be paid on April 1, 2024 for shareholders of record on March 15, 2024.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Calculated in accordance with our amended credit facilities agreement which is available on SEDAR+ at www.sedarplus.com.

Environmental Stewardship

The energy industry and society are undergoing an evolution toward lower carbon intensity, and we believe that oil and gas will be instrumental in this energy evolution. As a responsible energy producer, we are committed to reducing greenhouse gas ("GHG") emissions from our operations, minimizing freshwater use, and reclaiming our assets at the end of their economic life.

GHG Emissions

We are committed to monitoring GHG emissions from our operations, setting targets to reduce our GHG emissions intensity, and pursuing cost-effective strategies to produce energy for society with a lower carbon intensity. Our emissions reduction strategy includes increased gas conservation and destruction, reusing associated gas as fuel for field activities, capturing and reducing emissions from storage tanks, along with monitoring and preventing fugitive emissions.

Our corporate objective set in 2019 was to reduce our GHG emissions intensity (kg of CO2e per boe) by 65% by 2025 (set on our Canadian assets), relative to our 2018 baseline. In 2023, we invested $12 million in GHG reduction capital, reduced our GHG emissions intensity by 9% and achieved our 65% target two years early.

Continuous improvement is an important element of our corporate culture and we intend to set the bar higher. We are in the process of road mapping 2030 GHG reduction targets. Further details will be available in our 2023 ESG Report to be released in July 2024.

In 2024, we will invest approximately $18 million as part of our GHG mitigation program as we continue to invest in monitoring and lowering GHG emissions from our operations.

GHG Emissions Intensity (Scope 1 and Scope 2)[1] - Segment Canada

	2018 Baseline	2019	2020	2021	2022	2023[2]	2025 Target
kg CO_2e/boe	122	103	64	57	47	43	43

Water Management

As a responsible energy producer we are committed to pursuing water management strategies that minimize our freshwater use to help support long-term water security and maintain healthy ecosystems in our operating areas. In 2024, we anticipate investing $3 million in water management to expand our water storage and recycling infrastructure.

Abandonment and Reclamation

Our commitment to responsible resource development also extends to the retirement of our assets at the end of their economic life. We plan for full lifecycle development of our properties, which includes the abandonment, reclamation, and full restoration at the end of asset life. At December 31, 2020, we had an end of life well inventory of approximately 4,500 wells. We have committed to reducing this well inventory to zero by 2040, which represents proactive management of future financial obligations as well as regulatory compliance.

In 2023, we invested $26 million to complete 291 well abandonments. In 2024, we will continue our abandonment and reclamation program with approximately $30 million being directed to pipeline, wellbore and facility decommissioning along with well site reclamations.

Abandonment and Reclamation

	2018	2019	2020	2021	2022	2023	2024 Plan
Number of wells abandoned (gross)	110	113	99	237	379	291	260
Spending in abandonment/reclamation ($ million) (3)	$ 14	$ 15	$ 9	$ 10	$ 34	$ 26	$ 30

(1) Corporate emissions are reported based on the operating control method of the GHG Protocol. GHG emissions from 2018-2022 are calculated using the Global Warming Potential ("GWP") values from the IPCC's Fifth Assessment ("AR5"). We have restated historical emissions with the update to AR5, the operating control method of the GHG Protocol.
(2) 2023 data is not yet third party verified.
(3) Spending includes government grants received for abandonment and reclamations of $2 million in 2020, $3 million in 2021 and $16 million in 2022.

Year-end 2023 Reserves

Baytex's year-end 2023 proved and probable reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent qualified reserves evaluator. All of our oil and gas properties were evaluated in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants ("GLJ") and Sproule Associates Limited ("Sproule") as of January 1, 2024.

For additional information regarding Baytex's reserves as at December 31, 2023, see Baytex's Annual Information Form for the year ended December 31, 2023 on Baytex's SEDAR+ profile at www.sedarplus.com, and Baytex's U.S. Form 40-F for the year ended December 31, 2023 on EDGAR at www.sec.gov/edgar.shtml., each of which are anticipated to be filed on February 28, 2024.

Reserves Summary

On June 20, 2023, Baytex completed the strategic acquisition of Ranger, adding quality scale in the Eagle Ford and reinforcing a resilient and sustainable business. Our 2023 reserves report reflects this acquisition with a meaningful increase in our reserves base.

- Proved developed producing ("PDP") reserves increased by 49%, from 124 MMboe to 185 MMboe. Proved reserves ("1P") increased by 55%, from 264 MMboe to 410 MMboe. Proved plus probable reserves ("2P") increased by 51%, from 438 MMboe to 663 MMboe.
- Reserves on a 1P basis are comprised of 82% oil and NGLs (46% light oil, 23% NGLs, 12% heavy oil and 1% bitumen) and 18% natural gas.
- In Canada, we invested $463 million on exploration and development expenditures and replaced 131% of production on a 2P basis, net of the divestiture of our Viking assets at Forgan and Plato. The divestiture reduced 1P and 2P reserves by 11 MMboe and 17 MMboe, respectively.
- In the Eagle Ford, 1P and 2P reserves increased 117% and 130%, respectively. Reserves associated with the Ranger assets total 175 MMboe on a 1P basis, and 258 MMboe on a 2P basis, consistent with our assessment of Ranger's reserves at year-end 2022. The Ranger acquisition enhanced the quality of Baytex's reserves base, adding high value light oil and natural gas.
- Future development costs ("FDC") on a 1P basis increased to $6.0 billion ($2.7 billion at year-end 2022) and on a 2P basis, increased to $9.1 billion ($4.3 billion at year-end 2022). The increase in FDC is largely attributable to the Ranger acquisition, as well as modest inflationary pressures across our portfolio.
- Finding and development ("F&D") costs, including changes in FDC, were $24.23/boe for PDP reserves, $29.82/boe for 1P reserves and $28.68/boe for 2P reserves.
- Generated a PDP recycle ratio of 1.7x and a 1P recycle ratio of 1.4x based on a 2023 operating netback[1] of $41.00/boe.
- At year-end 2023, the present value of our 2P reserves, discounted at 10% before tax, is estimated to be $7.8 billion ($5.9 billion at year-end 2022). The increase is largely attributable to the Ranger acquisition and partially offset by the divestiture

of our Viking assets at Forgan and Plato and technical revisions associated with our legacy non-operated Eagle Ford asset and retained Viking assets.

(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.

The following table sets forth our gross and net reserves volumes at December 31, 2023 by product type and reserves category. Please note that the data in the table may not add due to rounding.

Reserves Summary

	Light and Medium Oil	Tight Oil	Heavy Oil	Bitumen	Total Oil	Natural Gas Liquids (3)	Conventional Natural Gas (4)	Shale Gas	Total (5)
Reserves Summary	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(MMcf)**	**(MMcf)**	**(Mboe)**
Gross (1)									
Proved producing	9,690	70,573	31,218	1,679	113,159	38,394	52,758	145,556	184,606
Proved developed non-producing	414	3,703	1,416	-	5,533	1,814	1,205	6,761	8,675
Proved undeveloped	15,699	88,506	18,445	2,105	124,754	54,631	23,948	201,607	216,978
Total proved	25,803	162,782	51,078	3,783	243,447	94,840	77,910	353,924	410,259
Total probable	14,997	85,238	32,935	45,754	178,923	42,334	38,246	151,764	252,925
Proved plus probable	40,799	248,020	84,013	49,537	422,370	137,173	116,156	505,688	663,184
Net (2)									
Proved producing	9,128	53,944	26,283	1,564	90,918	29,180	47,825	111,300	146,619
Proved developed non-producing	383	2,789	1,260	-	4,431	1,361	1,076	5,087	6,819
Proved undeveloped	14,882	68,154	16,292	1,916	101,243	41,630	20,760	154,239	172,039
Total proved	24,392	124,886	43,834	3,480	196,591	72,172	69,661	270,627	325,478
Total probable	13,910	65,548	27,331	36,517	143,306	32,687	33,578	118,279	201,303
Proved plus probable	38,302	190,434	71,165	39,997	339,897	104,859	103,238	388,906	526,781

Notes:

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others plus royalty interest reserves.
(3) Natural Gas Liquids includes condensate.
(4) Conventional Natural Gas includes associated, non-associated and solution gas.
(5) 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.

Reserves Reconciliation

The following table reconciles the year-over-year changes in our gross reserves volumes by product type and reserves category. Please note that the data in the table may not add due to rounding.

Proved Reserves - Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil	Tight Oil	Heavy Oil	Bitumen	Total Oil	Natural Gas Liquids (3)	Conventional Natural Gas (4)	Shale Gas	Total (5)
	(Mbbls)	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(MMcf)**	**(MMcf)**	**(Mboe)**
December 31, 2022	41,951	48,563	51,058	4,608	146,180	69,765	86,872	202,967	264,251
Extensions	2,039	21,367	9,402	-	32,808	8,587	1,845	40,849	48,510
Technical Revisions (2)	(1,952)	(1,472)	2,176	(261)	(1,509)	(3,997)	4,451	(7,782)	(6,062)
Acquisitions	-	108,091	7	-	108,098	26,379	-	143,499	158,394
Dispositions	(11,417)	-	-	-	(11,417)	(14)	(267)	-	(11,475)
Economic Factors	180	25	741	75	1,021	36	928	86	1,226
Production	(4,999)	(13,793)	(12,305)	(638)	(31,735)	(5,916)	(15,919)	(25,695)	(44,586)
December 31, 2023	25,803	162,782	51,078	3,783	243,447	94,840	77,910	353,924	410,259

Probable Reserves - Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil	Tight Oil	Heavy Oil	Bitumen	Total Oil	Natural Gas Liquids (3)	Conventional Natural Gas (4)	Shale Gas	Total (5)
	(Mbbls)	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(MMcf)**	**(MMcf)**	**(Mboe)**
December 31, 2022	21,881	20,719	34,526	45,751	122,877	28,728	45,786	84,633	173,342
Extensions	289	10,650	3,326	-	14,265	4,510	899	18,478	22,004
Technical Revisions (2)	(1,467)	(1,080)	(5,336)	25	(7,857)	(1,730)	(8,835)	(5,274)	(11,939)
Acquisitions	-	54,926	2	-	54,928	10,794	-	53,785	74,685
Dispositions	(5,772)	-	-	-	(5,772)	(4)	(71)	-	(5,787)
Economic Factors	65	23	416	(22)	482	36	467	142	620
Production	-	-	-	-	-	-	-	-	-
December 31, 2023	14,997	85,238	32,935	45,754	178,923	42,334	38,246	151,764	252,925

Proved Plus Probable Reserves - Gross Volumes (1) (Forecast Prices)

	Light and Medium Oil	Tight Oil	Heavy Oil	Bitumen	Total Oil	Natural Gas Liquids (3)	Conventional Natural Gas (4)	Shale Gas	Total (5)
	(Mbbls)	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(Mbbls)**	**(MMcf)**	**(MMcf)**	**(Mboe)**
December 31, 2022	63,832	69,283	85,584	50,359	269,058	98,493	132,658	287,600	437,593
Extensions	2,328	32,017	12,728	-	47,073	13,096	2,744	59,327	70,514

Technical Revisions [2]	(3,419)	(2,552)	(3,160)	(236)	(9,367)	(5,727)	(4,384)	(13,056)	(18,001)
Acquisitions	-	163,017	9	-	163,026	37,172	-	197,284	233,079
Dispositions	(17,188)	-	-	-	(17,188)	(18)	(338)	-	(17,262)
Economic Factors	245	49	1,157	52	1,503	73	1,395	228	1,846
Production	(4,999)	(13,793)	(12,305)	(638)	(31,735)	(5,916)	(15,919)	(25,695)	(44,586)
December 31, 2023	40,799	248,020	84,013	49,537	422,370	137,173	116,156	505,688	663,184

Notes:

(1) "Gross" reserves means the total working interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.
(2) Negative technical revisions in light and medium oil are predominantly associated with higher field operating costs in our Viking asset truncating end of life forecasts and actual performance not meeting forecast. Negative technical revisions in tight oil, shale gas and natural gas liquids in our legacy non-operated Eagle Ford assets are predominantly associated with actual performance not meeting forecast and the removal of locations due to inventory consolidation and spacing changes. Negative probable technical revisions in heavy oil are predominantly associated with performance re-characterization of undeveloped locations in the Peace River area. Positive proved technical revisions in heavy oil are predominantly associated with improved performance of producing wells in Peace River, Lloydminster and Peavine areas.
(3) Conventional natural gas includes associated, non-associated and solution gas.
(4) 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.

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserves categories noted below.

Future Development Costs ($ millions)	**Proved Reserves**	**Proved Plus Probable Reserves**
2024	1,038	1,070
2025	1,256	1,313
2026	1,334	1,442
2027	1,227	1,580
2028	1,060	1,451
Remainder	72	2,196
Total FDC undiscounted	5,986	9,051

F&D and FD&A Costs - including future development costs

Based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel, the efficiency of our capital program is summarized in the following table.

$ millions except for per boe amounts	**2023**	**2022**	**2021**	**3 Year**
Proved plus Probable Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 1,012.8	$ 521.5	$ 313.3	$ 1,847.6
Net change in Future Development Costs	$ 841.2	$ 588.6	$ 147.4	$ 1,577.2
Gross Reserves additions (MMboe)	64.6[1]	26.2	18.8	109.6
F&D Costs ($/boe)	$ 28.68	$ 42.34	$ 24.55	$ 31.24
Finding, Development & Acquisition ("FD&A") Costs				
Exploration and development expenditures and net acquisitions	$ 3,948.5	$ 497.2	$ 307.1	$ 4,752.8
Net change in Future Development Costs	$ 4,763.6	$ 537.6	$ 144.4	$ 5,445.6
Gross Reserves additions (MMboe)	270.2	17.2	18.4	305.8
FD&A Costs ($/boe)	$ 32.25	$ 60.05	$ 24.55	$ 33.35
Proved Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 1,012.8	$ 521.5	$ 313.3	$ 1,847.6
Net change in Future Development Costs	$ 491.7	$ 320.1	$ 308.6	$ 1,120.4
Gross Reserves additions (MMboe)	50.5[1]	21.4	35.2	107.0
F&D Costs ($/boe)	$ 29.82	$ 39.40	$ 17.67	$ 27.74
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$ 3,948.5	$ 497.2	$ 307.1	$ 4,752.8
Net change in Future Development Costs	$ 3,290.6	$ 285.0	$ 316.8	$ 3,892.4
Gross Reserves additions (MMboe)	190.6	16.6	36.1	243.2
FD&A Costs ($/boe)	$ 37.98	$ 47.25	$ 17.30	$ 35.55
Proved Developed Producing Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 1,012.8	$ 521.5	$ 313.3	$ 1,847.6
Gross Reserves additions (MMboe)	41.8[1]	27.2	38.2	107.2
F&D Costs ($/boe)	$ 24.23	$ 19.20	$ 8.20	$ 17.24
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$ 3,948.5	$ 497.2	$ 307.1	$ 4,752.8
Gross Reserves additions (MMboe)	104.8	26.0	38.1	168.9
FD&A Costs ($/boe)	$ 37.69	$ 19.13	$ 8.06	$ 28.14

Note:

(1) Gross reserve additions with respect to finding & development costs include 4.7 MMboe of PDP reserve additions, 6.8 MMboe of proved reserves additions and 10.2 MMboe of proved plus probable reserves additions, which in each case, reflect reserves developed on the acquired Ranger assets after closing of the acquisition. In the reserves reconciliation, these reserve additions are included in the Acquisitions category to align with NI 51-101.

Forecast Prices and Costs

The following table summarizes the forecast prices used in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2023. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of McDaniel, GLJ and Sproule as of January 1, 2024.

Year	WTI Crude Oil US$/bbl	Edmonton Light Crude Oil $/bbl	Western Canadian Select $/bbl	Henry Hub US$/MMbtu	AECO Spot $/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2023 act.	77.55	100.40	79.60	2.55	2.95	3.9	0.740
2024	73.67	92.91	76.74	2.75	2.20	-	0.752
2025	74.98	95.04	79.77	3.64	3.37	2.0	0.752
2026	76.14	96.07	81.12	4.02	4.05	2.0	0.755
2027	77.66	97.99	82.88	4.10	4.13	2.0	0.755
2028	79.22	99.95	85.04	4.18	4.21	2.0	0.755
2029	80.80	101.94	86.74	4.27	4.30	2.0	0.755
2030	82.42	103.98	88.47	4.35	4.38	2.0	0.755
2031	84.06	106.06	90.24	4.44	4.47	2.0	0.755
2032	85.74	108.18	92.04	4.53	4.56	2.0	0.755
2033	87.46	110.35	93.89	4.62	4.65	2.0	0.755
Thereafter			Escalation rate of 2.0%			2.0	0.755

Net Present Value of Reserves [1] (Forecast Prices and Costs)

The following table summarizes the McDaniel estimate of the net present value before income taxes of the future net revenue attributable to our reserves.

Reserves at December 31, 2023 ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	4,443	3,991	3,507	3,133
Proved developed non-producing	291	223	186	161
Proved undeveloped	3,295	2,037	1,264	761
Total proved	8,029	6,252	4,957	4,055
Probable	7,773	4,445	2,843	1,971
Total Proved Plus Probable (before tax)	15,802	10,697	7,800	6,026

Note:

(1) Includes abandonment, decommissioning and reclamation costs for all producing and non-producing wells and facilities.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2023 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR+ at www.sedarplus.com and EDGAR at www.sec.gov/edgar.shtml.

Conference Call Tomorrow
9:00 a.m. MST (11:00 a.m. EST)

Baytex will host a conference call tomorrow, February 29, 2024, starting at 9:00am MST (11:00am EST). 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/baytex2023q4.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 2024 strategy including our commitment to a disciplined, returns-based capital allocation philosophy and the anticipated effect of such philosophy on per-share returns; that we expect to allocate capital efficiently and respond to changes in regional commodity prices and economic factors; expected annual production growth over the next five years and our projected 2028 production; our intention to allocate free cash flow to each of debt repayment and shareholder returns (including share buybacks and quarterly dividends) and the expected amount of such free cash flow to be allocated; our expectation to generate meaningful *free cash flowin 2024, including the anticipated amount and timing thereof; our intention to direct additional free cash flowto shareholder returns once reaching our total debt target; our total debt target; our intended exploration plans across our heavy oil portfolio, including our drilling plans; our commodity hedging program, the percentage of our 2024 net crude exposure that is hedged, and the ability of such program to mitigate volatility in commodity prices; our targeted improvement in operated drilling and completion costs per lateral foot; our guidance regarding exploration and development expenditures and production in 2024; our drilling plans in the Pembina Duvernay and our intention to progress the Pembina Duvernay, delineate our Clearwater and Mannville heavy oil positions and deliver strong drilling and completion performance in the Eagle Ford and Viking regions; our commitment to monitoring GHG emissions, setting targets and pursuing cost-effective decarbonization strategies; our 2025 GHG emissions intensity reduction target and our strategies to reach the target; our 2024 expected investment into GHG mitigation, to expand our water storage and recycling infrastructure, and into wellbore and facility decommissioning along with well site reclamations; our abandonment and reclamation commitments, including the anticipated number of wells; future development costs, F&D and FD&A; forecast prices for oil and natural gas; forecast inflation and exchange rates; and the net present value before income taxes of the future net revenue attributable to our reserves. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.*

These forward-looking statements are based on certain key assumptions regarding, among other things: oil and natural gas prices and differentials between light, medium and heavy crude oil prices; well production rates and reserve volumes; success obtained in drilling newwells; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; operating costs; our ability to borrowunder 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; our ability to market oil and natural gas successfully; that we will have sufficient financial resources in the future to provide shareholder returns; 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 risk of an extended period of lowoil and natural gas prices; risks associated with our ability to develop our properties and add reserves; that we may not achieve the expected benefits of acquisitions and we may sell assets belowtheir carrying value; the availability and cost of capital or borrowing; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; the impact of an energy transition on demand for petroleum productions; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; changes in income tax or other laws or government incentive programs; risks associated with large projects; risks associated with higher a higher concentration of activity and tighter drilling spacing; costs to develop and operate our properties; risks associated with achieving our total debt target, production guidance, exploration and development expenditures guidance; the amount of free cash flowwe expect to generate; risk that the board of directors determines to allocate capital other than as set forth herein; current or future controls, legislation or regulations; restrictions on or access to water or other fluids; public perception and its influence on the regulatory regime; newregulations on hydraulic fracturing; 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; risks associated with a third-party operating our Eagle Ford properties; additional risks associated with our thermal heavy crude oil projects; our ability to compete with other organizations in the oil and gas industry; risk that we do not achieve our GHG emissions intensity reduction target; risks associated with our use of information technology systems; adverse 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 associated with expansion into newactivities; the impact of Indigenous claims; risks of counterparty default; impact of geopolitical risk and conflicts; loss of foreign private issuer status; conflicts of interest between the Corporation and its directors and officers; variability of share buybacks and dividends; 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. Readers are cautioned that the foregoing list of risk factors is not exhaustive.Newrisk factors emerge from time to time, and it is not possible for management to predict all of such factors and to assess in advance the impact of each such factor on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements.

The future acquisition of our common shares pursuant to a share buyback (including through its NCIB), if any, and the level thereof is uncertain. Any decision to pay dividends on the Common Shares (including the actual amount, the declaration date, the record date and the payment date in connection therewith) or acquire Common Shares pursuant to a share buyback will be subject to the discretion of the Board and may depend on a variety of factors, including, without limitation, the Corporation's business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions (including covenants contained in the agreements governing any indebtedness that the Corporation has incurred or may incur in the future, *including the terms of the Credit Facilities) and satisfaction of the solvency tests imposed on the Corporation under applicable corporate law. There can be no assurance of the number of Common Shares that the Corporation will acquire pursuant to a share buyback, if any, in the future. Further, the payment of dividends to shareholders is not assured or guaranteed and dividends may be reduced or suspended entirely.*

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, 2023, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission on February 28, 2024 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.

This press release contains information that may be considered a financial outlook under applicable securities laws about the Corporation's potential financial position, including, but not limited to, our 2024 guidance for development expenditures; our expected 2024 free cash flow, and our intentions of allocating our annual free cash flow to shareholder returns through a share buyback and debt reduction; all of which are subject to numerous assumptions, risk factors, limitations and qualifications, including those set forth in the above paragraphs. The actual results of operations of the Corporation and the resulting financial results will vary from the amounts set forth in this press release and such variations may be material. This information has been provided for illustration only and with respect to future periods are based on budgets and forecasts that are speculative and are subject to a variety of contingencies and may not be appropriate for other purposes. Accordingly, these estimates are not to be relied upon as indicative of future results. Except as required by applicable securities laws, the Corporation undertakes no obligation to update such financial outlook, whether as a result of new information, future events or otherwise. The financial outlook contained in this press release was made as of the date of this press release and was provided for the purpose of providing further information about the Corporation's potential future business operations. Readers are cautioned that the financial outlook contained in this press release is not conclusive and is subject to change.

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

Specified Financial Measures

In this press release, we refer to certain financial measures (such as free cash flow, operating netback, working capital deficiency, 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 gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. This press release also contains the terms "adjusted funds flow" and "net debt" which are considered capital management measures. We believe that inclusion of these specified financial measures provides useful information to financial statement users when evaluating the financial results of Baytex.

Non-GAAP Financial Measures

Total sales, net of blending and other expense

Total sales, net of blending and other expense 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 used to assess our operating performance and our ability to generate cash margin on a unit of production basis. Operating netback is comprised of petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense.

The following table reconciles operating netback to petroleum and natural gas sales.

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2023**	September 30, 2023	December 31, 2022	**2023**	2022
Petroleum and natural gas sales	**$ 1,065,515**	$ 1,163,010	$ 648,986	**$ 3,382,621**	$ 2,889,045
Blending and other expense	**(62,296)**	(49,830)	(50,174)	**(224,802)**	(189,454)
Total sales, net of blending and other expense	**1,003,219**	1,113,180	598,812	**3,157,819**	2,699,591
Royalties	**(228,570)**	(240,049)	(121,691)	**(669,792)**	(562,964)
Operating expense	**(164,873)**	(174,119)	(104,335)	**(570,839)**	(422,666)
Transportation expense	**(29,744)**	(27,983)	(14,817)	**(89,306)**	(48,561)
Operating netback	**$ 580,032**	$ 671,029	$ 357,969	**$ 1,827,882**	$ 1,665,400

Free cash flow

We use free cash flow to evaluate our financial performance and to assess the cash available for debt repayment, common *share repurchases, dividends and acquisition opportunities. Free cash flow is comprised of cash flows from operating activities adjusted for changes in non-cash working capital, transaction costs, additions to exploration and evaluation assets, additions to oil and gas properties, payments on lease obligations, and cash premiums on derivatives.*

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

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2023**	September 30, 2023	December 31, 2022	**2023**	2022
Cash flows from operating activities	**$ 474,452**	$ 444,033	$ 303,441	**$ 1,295,731**	$ 1,172,872
Change in non-cash working capital	**14,971**	126,075	(55,632)	**220,895**	(26,072)
Transaction costs	**5,079**	2,263	-	**49,045**	-
Additions to exploration and evaluation assets	**1,271**	(40)	(462)	**-**	(6,359)
Additions to oil and gas properties	**(200,537)**	(409,151)	(103,172)	**(1,012,787)**	(515,183)
Payments on lease obligations	**(4,451)**	(4,740)	(851)	**(11,527)**	(3,732)
Cash premiums on derivatives	**-**	-	-	**2,263**	-
Free cash flow	**$ 290,785**	$ 158,440	$ 143,324	**$ 543,620**	$ 621,526

Working capital deficiency

Working capital deficiency is calculated as cash, trade receivables, and prepaids and other assets net of trade payables, dividends payable, other long-term liabilities and share-based compensation liability. Working capital deficiency is used by management to measure the Company's liquidity. At December 31, 2023, the Company had $587.8 million of available credit facility capacity to cover any working capital deficiencies.

The following table summarizes the calculation of working capital deficiency.

	As at		
($ thousands)	**December 31, 2023**	September 30, 2023	December 31, 2022
Cash	**$ (55,815)**	$ (23,899)	$ (5,464)
Trade receivables	**(339,405)**	(540,679)	(222,108)
Prepaids and other assets	**(83,259)**	-	(6,377)
Trade payables	**477,295**	685,392	227,332
Share-based compensation liability	**35,732**	-	54,072
Other long-term liabilities	**19,147**	**-**	**-**
Dividends payable	**18,381**	19,138	**-**
Working capital deficiency	**$ 72,076**	$ 139,952	$ 47,455

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 (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period.

Average royalty rate

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

Operating netback per boe

Operating netback per boe is equal to operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent sales volume for the applicable period and is used to assess our operating performance on a unit of production basis.

Capital Management Measures

Net debt

We use net debt to monitor our current financial position and to evaluate existing sources of liquidity. We also use net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Net debt is comprised of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade payables, share-based compensation liability, dividends payable, other long-term liabilities, cash, trade receivables, and prepaids and other assets.

The following table summarizes our calculation of net debt.

	As at		
($ thousands)	**December 31, 2023**	September 30, 2023	December 31, 2022

Credit facilities	**$ 848,749**	$ 1,028,867	$ 383,031
Unamortized debt issuance costs - Credit facilities (1)	**15,987**	17,889	2,363
Long-term notes	**1,562,361**	1,600,397	547,598
Unamortized debt issuance costs - Long-term notes (1)	**35,114**	37,243	6,999
Trade payables	**477,295**	685,392	227,332
Share-based compensation liability	**35,732**	-	54,072
Dividends payable	**18,381**	19,138	**-**
Other long-term liabilities	**19,147**	-	-
Cash	**(55,815)**	(23,899)	(5,464)
Trade receivables	**(339,405)**	(540,679)	(222,108)
Prepaids and other assets	**(83,259)**	-	(6,377)
Net debt	**$ 2,534,287**	$ 2,824,348	$ 987,446

(1) Unamortized debt issuance costs were obtained from Note 8 Credit Facilities and Note 9 Long-term Notes from the Consolidated Financial Statements for the year ended December 31, 2023.

Adjusted funds flow

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

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

	Three Months Ended			Years Ended December 31	
($ thousands)	**December 31, 2023**	September 30, 2023	December 31, 2022	**2023**	2022
Cash flows from operating activities	**$ 474,452**	$ 444,033	$ 303,441	**$ 1,295,731**	$ 1,172,872
Change in non-cash working capital	**14,971**	126,075	(55,632)	**220,895**	(26,072)
Asset retirement obligations settled	**7,646**	9,252	7,743	**26,416**	18,351
Transaction costs	**5,079**	2,263	-	**49,045**	-
Cash premiums on derivatives	**-**	-	-	**2,263**	-
Adjusted funds flow	**$ 502,148**	$ 581,623	$ 255,552	**$ 1,594,350**	$ 1,165,151

Advisory Regarding Oil and Gas Information

The reserves information contained in this press release has been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2023, which will be filed on February 28, 2024. Listed below are cautionary statements that are specifically required by NI 51-101:

- *The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one boe (6 mcf/bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.*
- *With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.*
- *This press release contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.*

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. In the Eagle Ford, Baytex's net drilling locations include 358 proved and 148 probable locations as at December 31, 2023 and 318 unbooked locations. In the Viking, Baytex's net drilling locations include 586 proved and 173 probable locations as at December 31, 2023 and 238 unbooked locations. In Peace River (including Clearwater), Baytex's net drilling locations include 64 proved and 52 probable locations as at December 31, 2023 and 331 unbooked locations. In Lloydminster, Baytex's net drilling locations include 73 proved and 69 probable locations as at December 31, 2023 and 263 unbooked locations. In the Duvernay, Baytex's net drilling locations include 23 proved and 24 probable locations as at December 31, 2023 and 174 unbooked locations.

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 twelve months ended December 31, 2023. 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 December 31, 2023					Twelve Months Ended December 31, 2023				
	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	10,494	8	29	10,576	12,294	10,209	9	44	11,258	12,138
Lloydminster	12,736	40	-	1,445	13,017	11,852	23	-	1,298	12,092
Peavine	16,338	-	-	-	16,338	13,399	-	-	-	13,399
Canada - Light										
Viking	-	10,560	158	11,592	12,650	-	13,126	196	11,834	15,295
Duvernay	-	2,805	2,129	6,748	6,058	-	1,884	1,195	3,840	3,719
Remaining Properties	-	730	622	18,211	4,386	-	656	654	19,224	4,514
United States										
Eagle Ford	-	55,981	20,223	116,548	95,629	-	37,691	12,214	66,556	60,997
Total	39,569	70,123	23,160	165,121	160,373	35,460	53,389	14,303	114,011	122,154

This press release contains metrics commonly used in the oil and natural gas industry, such as "finding and development costs", "finding, development and acquisition costs", "PDP recycle ratio" and "1P recycle ratio." These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included in this press release to provide readers with additional measures to evaluate Baytex's performance, however, such measures are not reliable indicators of Baytex's future performance and future performance may not compare to Baytex's performance in previous periods and therefore such metrics should not be unduly relied upon.

Finding and development costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserves category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category.

Finding, development and acquisition costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserves category and the costs incurred on development and exploration activities and property acquisitions (net of dispositions) in the year by the change in reserves from the year for the reserve category.

Recycle ratio is calculated by dividing operating netback on a per boe basis by finding and development costs for the particular reserves category.

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.

Notice to United States Readers

The petroleum and natural gas reserves contained in this press release have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves". Additionally, NI 51-101 defines "proved reserves" and "probable reserves" differently from the SEC rules. Accordingly, proved and probable reserves disclosed in this press release may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves.

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, Baytex has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, Baytex's reserve estimates and production volumes in this press release may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

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. Approximately 85% of Baytex's production is weighted toward crude oil and natural gas liquids. Baytex's common shares trade on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE.

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

Brian Ector, Vice President, Capital Markets

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

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