Exhibit 99.1

BAYTEX ANNOUNCES FOURTH QUARTER AND FULL YEAR 2022 FINANCIAL AND OPERATING RESULTS AND YEAR END RESERVES

CALGARY, ALBERTA (February 23, 2023) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months and year ended December 31, 2022 (all amounts are in Canadian dollars unless otherwise noted).

“2022 was an exciting year for Baytex as we delivered strong operating results, generated record free cash flow, further strengthened our balance sheet and initiated direct shareholder returns. We generated a 4% year-over-year increase in production, repurchased 4.3% of our shares outstanding and reduced net debt by 30%. We expect another strong year in 2023 as we advance development across our high-quality oil weighted portfolio, further delineate our Peavine Clearwater acreage and progress our Duvernay light oil resource play. At current commodity prices, we anticipate hitting our next debt target during the third quarter at which point we intend to increase direct shareholder returns to 50% of our free cash flow," commented Eric T. Greager, President and Chief Executive Officer.

2022 Highlights

- Generated production of 86,864 boe/d (84% oil and NGL) in Q4/2022, an 8% increase over Q4/2021. Production for the full-year 2022 averaged 83,519 boe/d (84% oil and NGL), a 4% increase over 2021.
- Delivered adjusted funds flow(1) of $256 million ($0.47 per basic share) in Q4/2022 and $1,165 million ($2.09 per basic share) for 2022.
- Generated free cash flow(2) of $143 million ($0.26 per basic share) in Q4/2022 and $622 million ($1.11 per basic share) for 2022.
- Cash flows from operating activities was $303 million ($0.56 per basic share) in Q4/2022 and $1,173 million ($2.10 per basic share) for 2022.
- Exploration and development expenditures totaled $104 million in Q4/2022, bringing aggregate spending for 2022 to $522 million.
- Reduced net debt(1) by 30% in 2022 to $987 million, from $1.4 billion at year-end 2021.
- Repurchased 24.3 million common shares in 2022, representing 4.3% of our shares outstanding, at an average price of $6.54 per share.
- Reduced our GHG emissions intensity in 2022 by 15% from 2021 levels and have now achieved a 59% reduction, relative to our 2018 baseline.
- At year-end 2022, proved developed producing ("PDP") reserves total 124 MMboe, proved reserves (“1P”) total 264 MMboe and proved plus probable reserves (“2P”) total 438 MMboe(3). We generated a PDP recycle ratio of 2.8x and a 1P recycle ratio of 1.4x based on a 2022 operating netback(2) of $54.64/boe.
- The present value of our reserves, discounted at 10% before tax, is estimated to be $5.9 billion ($5.1 billion at year-end 2021). The increase is largely attributable to a higher commodity price forecast being utilized by our reserves evaluator (consultant average of approximately US$81/bbl WTI).
- Our net asset value at year-end 2022, discounted at 10% before tax, is $9.28 per share. This is based on the estimated reserves value plus a value for undeveloped acreage, net of long-term debt and working capital.

(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) Baytex's year-end 2022 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, 2022	September 30, 2022	December 31, 2021	**December 31, 2022**	December 31, 2021
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 648,986**	$ 712,065	$ 552,403	**$ 2,889,045**	$ 1,868,195
Adjusted funds flow (1)	**255,552**	284,288	214,766	**1,165,151**	745,628
Per share – basic	**0.47**	0.51	0.38	**2.09**	1.32
Per share – diluted	**0.46**	0.51	0.37	**2.07**	1.30
Free cash flow (2)	**143,324**	111,568	137,133	**621,526**	421,329
Per share – basic	**0.26**	0.20	0.24	**1.11**	0.75
Per share – diluted	**0.26**	0.20	0.24	**1.10**	0.74
Cash flows from operating activities	**303,441**	310,423	240,567	**1,172,872**	712,384
Per share – basic	**0.56**	0.56	0.43	**2.10**	1.26
Per share – diluted	**0.55**	0.56	0.42	**2.08**	1.25
Net income (loss)	**352,807**	264,968	563,239	**855,605**	1,613,600
Per share – basic	**0.65**	0.48	1.00	**1.53**	2.86
Per share – diluted	**0.64**	0.47	0.98	**1.52**	2.82
Capital Expenditures					
Exploration and development expenditures	**$ 103,634**	$ 167,453	$ 73,995	**$ 521,542**	$ 313,303
Acquisitions and divestitures	**937**	(25,460)	(5,414)	**(24,297)**	(6,247)
Total oil and natural gas capital expenditures	**$ 104,571**	$ 141,993	$ 68,581	**$ 497,245**	$ 307,056
Net Debt					
Credit facilities	**$ 385,394**	$ 450,051	$ 506,514	**$ 385,394**	$ 506,514
Long-term notes	**554,597**	648,207	885,920	**554,597**	885,920
Long-term debt	**939,991**	1,098,258	1,392,434	**939,991**	1,392,434
Working capital deficiency	**47,455**	15,301	17,283	**47,455**	17,283
Net debt (1)	**$ 987,446**	$ 1,113,559	$ 1,409,717	**$ 987,446**	$ 1,409,717
Shares Outstanding - basic (thousands)					
Weighted average	**546,279**	553,409	564,213	**557,986**	563,674
End of period	**544,930**	547,615	564,213	**544,930**	564,213
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 82.64**	$ 91.56	$ 77.19	**$ 94.23**	$ 67.92
MEH oil (US$/bbl)	**85.88**	96.15	78.89	**97.79**	69.26
MEH oil differential to WTI (US$/bbl)	**3.24**	4.59	1.70	**3.57**	1.34
Edmonton par ($/bbl)	**109.57**	116.79	93.29	**119.95**	80.23
Edmonton par differential to WTI (US$/bbl)	**(1.94)**	(2.13)	(3.15)	**(2.07)**	(3.92)
WCS heavy oil ($/bbl)	**77.37**	93.62	78.82	**98.94**	68.79
WCS differential to WTI (US$/bbl)	**(25.65)**	(19.87)	(14.63)	**(18.21)**	(13.05)
Natural gas					
NYMEX (US$/mmbtu)	**$ 6.26**	$ 8.20	$ 5.83	**$ 6.64**	$ 3.84
AECO ($/mcf)	**5.58**	5.81	4.94	**5.56**	3.56
CAD/USD average exchange rate	**1.3577**	1.3059	1.2600	**1.3016**	1.2536

	Three Months Ended			Twelve Months Ended	
	December 31, 2022	September 30, 2022	December 31, 2021	**December 31, 2022**	December 31, 2021
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**32,105**	33,247	34,986	**33,101**	35,789
Heavy oil (bbl/d)	**32,819**	29,244	23,482	**28,993**	22,188
NGL (bbl/d)	**7,661**	7,536	7,984	**7,575**	7,244
Total liquids (bbl/d)	**72,585**	70,027	66,452	**69,669**	65,221
Natural gas (mcf/d)	**85,679**	79,003	86,029	**83,101**	89,606
Oil equivalent (boe/d @ 6:1) (1)	**86,864**	83,194	80,789	**83,519**	80,156
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 598,812**	$ 671,120	$ 523,382	**$ 2,699,591**	$ 1,782,506
Royalties	**(121,691)**	(146,994)	(100,152)	**(562,964)**	(339,156)
Operating expense	**(104,335)**	(110,139)	(95,357)	**(422,666)**	(343,002)
Transportation expense	**(14,817)**	(12,771)	(8,169)	**(48,561)**	(32,261)
Operating netback (2)	**$ 357,969**	$ 401,216	$ 319,704	**$ 1,665,400**	$ 1,068,087
General and administrative	**(14,945)**	(12,003)	(11,481)	**(50,270)**	(40,804)
Cash financing and interest	**(19,711)**	(19,774)	(21,319)	**(80,386)**	(92,069)
Realized financial derivatives loss	**(49,665)**	(76,408)	(70,544)	**(334,481)**	(184,241)
Other (3)	**(18,096)**	(8,743)	(1,594)	**(35,112)**	(5,345)
Adjusted funds flow (4)	**$ 255,552**	$ 284,288	$ 214,766	**$ 1,165,151**	$ 745,628
Netback per boe (5)					
Total sales, net of blending and other expense (2)	**$ 74.93**	$ 87.68	$ 70.42	**$ 88.56**	$ 60.93
Royalties	**(15.23)**	(19.21)	(13.47)	**(18.47)**	(11.59)
Operating expense	**(13.06)**	(14.39)	(12.83)	**(13.86)**	(11.72)
Transportation expense	**(1.85)**	(1.67)	(1.10)	**(1.59)**	(1.10)
Operating netback (2)	**$ 44.79**	$ 52.41	$ 43.02	**$ 54.64**	$ 36.52
General and administrative	**(1.87)**	(1.57)	(1.54)	**(1.65)**	(1.39)
Cash financing and interest	**(2.47)**	(2.58)	(2.87)	**(2.64)**	(3.15)
Realized financial derivatives loss	**(6.21)**	(9.98)	(9.49)	**(10.97)**	(6.30)
Other (3)	**(2.26)**	(1.14)	(0.23)	**(1.16)**	(0.19)
Adjusted funds flow (4)	**$ 31.98**	$ 37.14	$ 28.89	**$ 38.22**	$ 25.49

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 2022 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 or transportation expense divided by barrels of oil equivalent production volume for the applicable period.

2023 Outlook

In 2023, we will advance development across our high-quality oil weighted portfolio, further delineate our Peavine Clearwater acreage and progress our Duvernay light oil resource play. We are committed to allocating capital efficiently to generate meaningful free cash flow and increasing direct shareholder returns. Our 2023 guidance remains unchanged as we target production of 86,000 to 89,000 boe/d with exploration and development expenditures of $575 to $650 million.

Based on the forward strip(1), we expect to generate approximately $450 million of free cash flow(2) in 2023. We expect to reach a net debt(3) level of $800 million during Q3/2023, at which time, we anticipate increasing direct shareholder returns to 50% of our free cash flow and accelerating our share buyback program.

The following table highlights our 2023 annual guidance.

	2023 Guidance
Exploration and development expenditures	$575 - $650 million
Production (boe/d)	86,000 - 89,000
Expenses:	
Average royalty rate (2)	20.0% - 22.0%
Operating (4)	$14.00 - $14.75/boe
Transportation (4)	$1.90 - $2.10/boe
General and administrative (4)	$52 million ($1.63/boe)
Interest (4)	$65 million ($2.04/boe)
Leasing expenditures	$4 million
Asset retirement obligations	$25 million

2022 Results

In 2022, we delivered strong operating results and further strengthened our business. We generated record free cash flow of $622 million ($1.11 per basic share), up from $421 million ($0.75 per basic share) in 2021.

During 2022, we initiated direct shareholder returns, allocating 25% of annual free cash flow to a share buyback program with 75% of free cash flow allocated to debt reduction. We repurchased 24.3 million common shares for $159 million, representing 4.3% of our shares outstanding, at an average price of $6.54 per share. In addition, we significantly strengthened our balance sheet, reducing net debt by 30% to $987 million, representing a net debt to EBITDA(5) ratio (trailing twelve months) of 0.8x.

Production for the full-year 2022 averaged 83,519 boe/d, a 4% increase compared to 80,156 boe/d in 2021, and consistent with our annual guidance. Production in Q4/2022 averaged 86,864 boe/d (84% oil and NGL), an 8% increase compared to 80,789 boe/d (82% oil and NGL) in Q4/2021. During the fourth quarter, production was reduced by approximately 1,500 boe/d due to extreme cold weather conditions during the month of December.

We maintained capital discipline despite inflationary pressures across our portfolio that was consistent with the industry and broader economy. Exploration and development expenditures totaled $104 million in Q4/2022 and $522 million for full-year 2022. We participated in the drilling of 269 (212.2 net) wells.

We delivered adjusted funds flow(3) of $256 million ($0.47 per basic share) in Q4/2022 and $1,165 million ($2.09 per basic share) in 2022. We recorded net income of $353 million ($0.65 per basic share) in Q4/2022 and $855.6 million ($1.53 per basic share) in 2022. During Q4/2022, we reversed $268 million of previously recorded impairments on our assets primarily as a result of higher forecasted commodity prices.

(1) 2023 pricing assumptions: WTI - US$75/bbl; WCS differential - US$19/bbl; MSW differential – US$2/bbl, NYMEX Gas - US$3.05/MMbtu; AECO Gas - $2.95/mcf and Exchange Rate (CAD/USD) - 1.35.
(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) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(4) Calculated as operating, transportation, general and administrative or interest expense divided by barrels of oil equivalent production volume for the applicable period.
(5) Calculated in accordance with the Credit Facilities Agreement.

Operating Results

Light Oil

Production in the Eagle Ford averaged 29,918 boe/d (78% oil and NGL) during Q4/2022 and 28,245 boe/d for the full-year 2022. In 2022, we invested $141 million on exploration and development in the Eagle Ford and generated an operating netback(1) of $582 million. During 2022, we participated in the drilling of 64 (15.8 net) wells and brought 68 (16.8 net) wells onstream. We expect to bring approximately 15 net wells onstream in 2023.

Production in the Viking averaged 14,625 boe/d (87% oil and NGL) during Q4/2022 and 16,239 boe/d for the full-year 2022. In 2022, we invested $168 million on exploration and development in the Viking and generated an operating netback of $479 million. During 2022, we drilled 137 (131.3 net) wells and brought 132 (126.9 net) wells onstream. We expect to bring approximately 144 net wells onstream in 2023.

Production in the Pembina Duvernay averaged 3,058 boe/d (81% oil and NGL) during Q4/2022 and 2,603 boe/d for the full-year 2022. In the Duvernay, we drilled a three-well pad in 2022 that provided increased confidence in capital execution and well performance. Our 2023 Duvernay program is expected to include two three-well pads as we continue to progress our understanding of the reservoir.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster (excluding our Clearwater development) produced a combined 23,999 boe/d (91% oil and NGL) during Q4/2022 and 23,834 boe/d for the full-year 2022. Our 2022 drilling program included 9 net Bluesky wells at Peace River and 28.1 net wells at Lloydminster. In 2022, we invested $113 million on exploration and development in Peace River and Lloydminster and generated an operating netback of $361 million. In 2023, we will drill approximately 10 net Bluesky wells at Peace River and 40 net wells at Lloydminster.

Clearwater

Production from our Peavine Clearwater development averaged 11,009 boe/d (100% oil) during Q4/2022 and 7,442 boe/d for the full-year 2022. In 2022, we invested $55 million on exploration and development on our Peavine Clearwater acreage and generated an operating netback of $142 million. During 2022, we drilled 22 (22.0 net) wells at Peavine and brought 23 (23.0 net) wells onstream. Initial well performance continues to outperform type curve assumptions and we now hold the top 15 initial rate wells (based on peak 30-day calendar rate) drilled across the play. We expect to bring approximately 31 net wells onstream at Peavine in 2023.

Our Peavine Clearwater acreage has emerged as one of the most highly economic plays in North America and has grown 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 prospective for Clearwater development.

Financial Liquidity

Our credit facilities total US$850 million and have a maturity date of April 1, 2026. These are not borrowing base facilities and do not require annual or semi-annual reviews. As of December 31, 2022, we had $765 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $717 million.

Our net debt(2), which includes our credit facilities, long-term notes and working capital, totaled $987 million at December 31, 2022, down from $1.1 billion at September 30, 2022 and $1.4 billion at December 31, 2021.

On June 1, 2022, we redeemed the remaining US$200 million principal amount of 5.625% long-term notes due 2024 at par. In addition, we repurchased and cancelled US$90 million principal amount of 8.75% long-term notes due 2027 during 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) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.

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 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 17 to our 2022 financial statements.

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 monitoring greenhouse gas (“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 objective is to reduce our corporate GHG emissions intensity (kg of CO2e per boe) by 65% by 2025, relative to our 2018 baseline. 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.

In 2022, we reduced our GHG emissions intensity by 15% from 2021 levels. This equates to a 59% reduction from our 2018 baseline and represents an annual reduction of 1.7 million tonnes of CO2e, which is equivalent to taking 340,000 cars off the road annually. In 2023, we will invest approximately $15 million as part of our GHG mitigation program and expect to reduce our GHG emissions intensity by another 7% below 2022 levels.

GHG Emissions Intensity (Scope 1 and Scope 2)

	2018 Baseline	2019	2020	2021	2022[(1)]	2025 Target
kg CO_2e/boe	112	95	61	54	46	39

Our commitment to responsible resource development also extends to the retirement of our assets when they've reached 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 2022, we invested $34 million (including $16 million of government grants) to complete 379 well abandonments. In 2023, we will continue our abandonment and reclamation program with approximately $25 million being directed to pipeline, wellbore and facility decommissioning along with well site reclamations.

Abandonment and Reclamation

	2018	2019	2020	2021	2022	2023 Plan
Number of wells abandoned (gross)	110	113	99	237	379	270
Spending in abandonment/reclamation ($ million) [(2)]	$ 14	$ 15	$ 9	$ 10	$ 34	$ 25

(1) Corporate emissions are reported based on the operating control method of the GHG Protocol. 2022 data is not yet third party verified.
(2) 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 2022 Reserves

Baytex's year-end 2022 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, 2023. Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2022, which will be filed on or before March 31, 2023.

Reserves Highlights

- Proved developed producing ("PDP") reserves total 124 MMboe (129 MMboe at year-end 2021), proved reserves ("1P") total 264 MMboe (278 MMboe at year-end 2021) and proved plus probable reserves ("2P") total 438 MMboe (451 MMboe at year-end 2021).
- In Canada, 1P and 2P reserves increased 1% and 2%, respectively. We invested $381 million on exploration and development expenditures in Canada and replaced 131% of production on a 2P basis with significant reserves additions coming from our Peavine heavy oil development. The divestiture of non-core natural gas assets during the fourth quarter reduced 1P and 2P reserves by 5 MMboe and 9 MMboe, respectively.
- In the Eagle Ford, 1P and 2P reserves declined 10%. The reduction in Eagle Ford reserves is largely attributable to adjustments in development plans and technical revisions associated with shale gas.
- Future development costs ("FDC") on a 1P basis increased to $2.7 billion ($2.4 billion at year-end 2021) and on a 2P basis, increased to $4.3 billion ($3.8 billion at year-end 2021). The increase in FDC is mainly attributable to inflationary pressures across our portfolio, consistent with inflationary pressures across the industry and the broader economy.
- Finding and development ("F&D") costs, including changes in FDC, were $19.20/boe for PDP reserves, $39.40/boe for 1P reserves and $42.34/boe for 2P reserves.
- Generated a PDP recycle ratio of 2.8x and a 1P recycle ratio of 1.4x based on a 2022 operating netback[(1)] of $54.64/boe.
- Reserves on a 1P basis are comprised of 82% oil and NGLs (34% light oil, 26% NGLs, 19% heavy oil and 2% bitumen) and 18% natural gas. PDP reserves represent 47% of 1P reserves (46% at year-end 2021) and 1P reserves represent 60% of 2P reserves (62% at year-end 2021).
- Baytex maintains a strong reserves life index of 8.3 years based on 1P reserves and 13.8 years based on 2P reserves.
- At year-end, 2022, the present value of our reserves, discounted at 10% before tax, is estimated to be $5.9 billion ($5.1 billion at year-end 2021). The increase is largely attributable to a higher commodity price forecast being utilized by our reserves evaluator (consultant average of approximately US$81/bbl WTI).
- Our net asset value at year-end 2022, discounted at 10% before tax, is $9.28 per share. This is based on the estimated reserves value plus a value for undeveloped acreage, net of long-term debt and working capital.

(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, 2022 by product type and reserves category. Please note that the data in the table may not add due to rounding.

Reserves Summary

Reserves Summary	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids [3] (Mbbls)	Conventional Natural Gas [4] (MMcf)	Shale Gas (MMcf)	Total [5] (Mboe)
Gross [1]									
Proved producing	16,144	25,913	29,187	939	72,183	28,796	59,803	80,928	124,434
Proved developed non-producing	993	1,894	1,624	—	4,510	1,734	1,239	4,686	7,231
Proved undeveloped	24,814	20,757	20,247	3,668	69,487	39,235	25,831	117,354	132,586
Total proved	41,951	48,563	51,058	4,608	146,180	69,765	86,872	202,967	264,251
Total probable	21,881	20,719	34,526	45,751	122,878	28,728	45,786	84,633	173,342
Proved plus probable	63,832	69,283	85,584	50,359	269,057	98,493	132,658	287,600	437,593
Net [2]									
Proved producing	15,049	19,250	24,694	879	59,872	21,502	53,606	60,467	100,386
Proved developed non-producing	883	1,395	1,444	—	3,723	1,279	1,105	3,453	5,761
Proved undeveloped	23,098	15,844	17,584	3,354	59,880	29,453	22,315	88,536	107,808
Total proved	39,030	36,490	43,722	4,233	123,474	52,234	77,026	152,456	213,955
Total probable	19,989	15,789	28,960	37,202	101,940	21,795	40,387	64,878	141,279
Proved plus probable	59,018	52,278	72,681	41,436	225,414	74,029	117,413	217,335	355,234

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 (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids [(3)] (Mbbls)	Conventional Natural Gas [(4)] (MMcf)	Shale Gas (MMcf)	Total [(5)] (Mboe)
December 31, 2021	46,009	53,216	46,003	4,838	150,067	72,137	104,423	231,439	278,181
Extensions	2,456	1,673	11,275	—	15,404	1,946	15,912	4,201	20,702
Technical Revisions [(2)]	(2,504)	(1,164)	3,034	344	(290)	(152)	4,658	(20,846)	(3,140)
Acquisitions	—	—	—	—	—	—	—	—	—
Dispositions	—	—	(1)	—	(1)	(743)	(24,363)	—	(4,804)
Economic Factors	1,320	395	686	69	2,470	536	3,450	1,298	3,797
Production	(5,331)	(5,556)	(9,939)	(644)	(21,470)	(3,960)	(17,207)	(13,125)	(30,485)
December 31, 2022	41,951	48,563	51,058	4,608	146,180	69,765	86,872	202,967	264,251

Probable Reserves – Gross Volumes [(1)] (Forecast Prices)

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids [(3)] (Mbbls)	Conventional Natural Gas [(4)] (MMcf)	Shale Gas (MMcf)	Total [(5)] (Mboe)
December 31, 2021	23,296	21,485	29,705	45,874	120,360	27,751	62,394	84,928	172,665
Extensions	636	904	3,744	—	5,285	602	4,183	1,883	6,898
Technical Revisions [(2)]	(2,414)	(1,796)	(866)	(136)	(5,211)	844	(1,880)	(2,647)	(5,121)
Acquisitions	—	—	—	—	—	—	—	—	—
Dispositions	—	—	—	—	—	(655)	(21,175)	—	(4,184)
Economic Factors	363	126	1,942	12	2,443	186	2,263	468	3,084
Production	—	—	—	—	—	—	—	—	—
December 31, 2022	21,881	20,719	34,526	45,751	122,877	28,728	45,786	84,633	173,342

Proved Plus Probable Reserves – Gross Volumes [(1)] (Forecast Prices)

	Light and Medium Oil (Mbbls)	Tight Oil (Mbbls)	Heavy Oil (Mbbls)	Bitumen (Mbbls)	Total Oil (Mbbls)	Natural Gas Liquids [(3)] (Mbbls)	Conventional Natural Gas [(4)] (MMcf)	Shale Gas (MMcf)	Total [(5)] (Mboe)
December 31, 2021	69,305	74,701	75,709	50,713	270,427	99,888	166,817	316,367	450,846
Extensions	3,093	2,577	15,019	—	20,689	2,549	20,095	6,085	27,601
Technical Revisions [(2)]	(4,917)	(2,960)	2,168	208	(5,500)	692	2,778	(23,492)	(8,261)
Acquisitions	—	—	—	—	—	—	—	—	—
Dispositions	—	—	(1)	—	(2)	(1,397)	(45,537)	—	(8,989)
Economic Factors	1,683	521	2,628	81	4,913	722	5,713	1,765	6,881
Production	(5,331)	(5,556)	(9,939)	(644)	(21,470)	(3,960)	(17,207)	(13,125)	(30,485)
December 31, 2022	63,832	69,283	85,584	50,359	269,058	98,493	132,658	287,600	437,593

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 due to inflationary impacts truncating end of life forecasts and natural variation in actual performance vs forecast. Negative technical revisions in tight oil are predominantly associated with higher field operating costs in our Eagle Ford asset due to inflationary impacts truncating end of life forecasts and natural variation in actual performance vs forecast. Negative technical revisions in shale gas are predominantly associated with natural variation in actual performance vs forecast in our Eagle Ford asset.

(3) Natural gas liquids include 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.

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
2023	490	516
2024	602	643
2025	510	625
2026	505	707
2027	494	569
Remainder	95	1,228
Total FDC undiscounted	2,695	4,288

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	2022	2021	2020	3 Year
Proved plus Probable Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 521.5	$ 313.3	$ 280.3	$ 1,115.2
Net change in Future Development Costs	$ 588.6	$ 147.4	$ (705.9)	$ 30.1
Gross Reserves additions (MMboe)	26.2	18.8	(38.4)	6.6
F&D Costs ($/boe)	$ 42.34	$ 24.55	$ 11.08	n.m.[(1)]
Finding, Development & Acquisition (“FD&A”) Costs				
Exploration and development expenditures and net acquisitions	$ 497.2	$ 307.1	$ 280.2	$ 1,084.5
Net change in Future Development Costs	$ 537.6	$ 144.4	$ (709.3)	$ (27.3)
Gross Reserves additions (MMboe)	17.2	18.4	(38.6)	(3.0)
FD&A Costs ($/boe)	$ 60.05	$ 24.55	$ 11.12	n.m.[(1)]
Proved Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 521.5	$ 313.3	$ 280.3	$ 1,115.2
Net change in Future Development Costs	$ 320.1	$ 308.6	$ (464.4)	$ 164.2
Gross Reserves additions (MMboe)	21.4	35.2	(13.1)	43.5
F&D Costs ($/boe)	$ 39.40	$ 17.67	$ 14.06	$ 29.44
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$ 497.2	$ 307.1	$ 280.2	$ 1,084.5
Net change in Future Development Costs	$ 285.0	$ 316.8	$ (464.4)	$ 137.4
Gross Reserves additions (MMboe)	16.6	36.1	(13.1)	39.5
FD&A Costs ($/boe)	$ 47.25	$ 17.30	$ 14.07	$ 30.92
Proved Developed Producing Reserves				
Finding & Development Costs				
Exploration and development expenditures	$ 521.5	$ 313.3	$ 280.3	$ 1,115.2
Gross Reserves additions (MMboe)	27.2	38.2	7.7	73.1
F&D Costs ($/boe)	$ 19.20	$ 8.20	$ 36.63	$ 15.27
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$ 497.2	$ 307.1	$ 280.2	$ 1,084.5
Gross Reserves additions (MMboe)	26.0	38.1	7.6	71.8
FD&A Costs ($/boe)	$ 19.13	$ 8.06	$ 36.64	$ 15.11

Note:
(1) Not meaningful.

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves at year-end 2022 by annualized Q4/2022 production.

		Reserves Life Index (years)	
	Q4/2022 Production	Proved	Proved Plus Probable
Crude Oil and NGL (bbl/d)	72,585	8.2	13.9
Natural Gas (Mcf/d)	85,679	9.3	13.4
Oil Equivalent (boe/d)	86,864	8.3	13.8

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, 2022. 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, 2023.

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
2022 act.	94.65	120.55	98.85	6.40	5.55	6.9	0.770
2023	80.33	103.76	76.54	4.74	4.23	—	0.745
2024	78.50	97.74	77.75	4.50	4.40	2.3	0.765
2025	76.95	95.27	77.55	4.31	4.21	2.0	0.768
2026	77.61	95.58	80.07	4.40	4.27	2.0	0.772
2027	79.16	97.07	81.89	4.49	4.34	2.0	0.775
2028	80.74	99.01	84.02	4.58	4.43	2.0	0.775
2029	82.36	100.99	85.73	4.67	4.51	2.0	0.775
2030	84.00	103.01	87.44	4.76	4.60	2.0	0.775
2031	85.69	105.07	89.20	4.86	4.69	2.0	0.775
2032	87.40	106.69	91.11	4.95	4.79	2.0	0.775
Thereafter	Escalation rate of 2.0%					2.0	0.775

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, 2022 ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	2,821	2,485	2,197	1,978
Proved developed non-producing	296	225	185	159
Proved undeveloped	3,007	2,055	1,485	1,108
Total proved	6,124	4,765	3,867	3,246
Probable	5,303	3,065	2,011	1,434
Total Proved Plus Probable (before tax)	11,427	7,830	5,878	4,680

Note:

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

Net Asset Value (Forecast Prices and Costs)

Our estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before income taxes, as estimated by McDaniel at year-end, plus the estimated value of our undeveloped land holdings, less net debt. This calculation can vary significantly depending on the oil and natural gas price assumptions. In addition, this calculation assumes only the reserves identified in the reserves report with no further acquisitions or incremental development.

The following table sets forth our net asset value as at December 31, 2022.

($ millions, except per share amounts, discounted at)	5%	10%	15%
Net present value of proved plus probable reserves (1)	7,830	5,878	4,680
Undeveloped land holdings (2)	166	166	166
Net Debt (3)	(987)	(987)	(987)
Net Asset Value	7,009	5,057	3,859
Net Asset Value per Share (4)	12.86	9.28	7.08

Notes:
(1) Includes abandonment, decommissioning and reclamation costs for all producing and non-producing wells and facilities.
(2) The value of undeveloped land holdings generally represents the estimated replacement cost of our undeveloped land.
(3) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(4) Based on 544.9 million common shares outstanding as at December 31, 2022.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2022 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

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

Baytex will host a conference call tomorrow, February 24, 2023, 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/baytex2022ye.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 2023 development plans with respect to our high quality oil weighted portfolio and our Peavine acreage and Duvernay play; that we expect to hit our next debt target during Q3/2023 at which point we intend to increase our direct shareholder returns to 50% of free cash flow; our commitment to allocate capital effectively to generate meaningful free cash flow and increase direct shareholder returns; that we expect to generate $450 million of free cash flow in 2023; our guidance for 2023 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; in the Eagle Ford that we expect to bring 15 net wells onstream in 2023; in the Viking that we expect to bring 144 nets wells onstream in 2023; in the Duvernay we expect to drill two three-well pads; in 2023, that we will drill ~10 net Bluesky wells at Peace River and 40 net wells at Lloydminster; at Peavine bring 31 wells on stream in 2023; that we have de-risked 50 of 80 sections of Peavine lands, hold 125 sections that are highly prospective for Clearwater development and believe the lands hold the potential for greater than 250 locations with production growing to 15,000 bbl/day; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility, the percentage of our 2023 net crude exposure that is hedged; that we are committed 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 2023 expected spending on GHG mitigation; our commitment to abandon and reclaim 4,500 wells by 2040, the number of wells we expect to abandon and our expected 2023 spending on abandonment and reclamation; future development costs, F&D and FD&A; our reserves life index; forecast prices for oil and natural gas; forecast inflation and exchange rates; the net present value before income taxes of the future net revenue attributable to our reserves; the value of our undeveloped land holdings and our estimated net asset value. 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; 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; 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 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 crude 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; the risk that we may not have sufficient financial resources in the future to provide shareholder returns; and other factors, many of which are beyond our control. Readers are cautioned that the foregoing list of risk factors is not exhaustive. New risk 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 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, our business performance, financial condition, financial requirements, growth plans, expected capital requirements and other conditions existing at such future time including, without limitation, contractual restrictions and satisfaction of the solvency tests imposed on us under applicable corporate law. There can be no assurance of the number of Common Shares that we will acquire pursuant to a share buyback, if any, in the future.

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2022, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission on February 23, 2023 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 2023 guidance for development expenditures; our expected 2023 free cash flow; 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, 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.

	Years Ended December 31	
($ thousands)	**2022**	2021
Petroleum and natural gas sales	**$ 2,889,045**	$ 1,868,195
Blending and other expense	**(189,454)**	(85,689)
Total sales, net of blending and other expense	**2,699,591**	1,782,506
Royalties	**(562,964)**	(339,156)
Operating expense	**(422,666)**	(343,002)
Transportation expense	**(48,561)**	(32,261)
Operating netback	**$ 1,665,400**	$ 1,068,087

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, additions to exploration and evaluation assets, additions to oil and gas properties and payments on lease obligations.

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

	Years Ended December 31	
($ thousands)	**2022**	2021
Cash flows from operating activities	**$ 1,172,872**	$ 712,384
Change in non-cash working capital	**(26,072)**	26,582
Additions to exploration and evaluation assets	**(6,359)**	(3,298)
Additions to oil and gas properties	**(515,183)**	(310,005)
Payments on lease obligations	**(3,732)**	(4,334)
Free cash flow	**$ 621,526**	$ 421,329

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 and other payables, cash, and trade and other receivables.
The following table summarizes our calculation of net debt.

($ thousands)		**December 31, 2022**		December 31, 2021
Credit facilities	**$**	**383,031**	$	505,171
Unamortized debt issuance costs - Credit facilities (1)		**2,363**		1,343
Long-term notes		**547,598**		874,527
Unamortized debt issuance costs - Long-term notes (1)		**6,999**		11,393
Trade and other payables		**281,404**		190,692
Cash		**(5,464)**		—
Trade and other receivables		**(228,485)**		(173,409)
Net debt	**$**	**987,446**	$	1,409,717

(1) Unamortized debt issuance costs were obtained from Note 7 Credit Facilities and Note 8 Long-term Notes from the Consolidated Financial Statements for the year ended December 31, 2022.

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 and asset retirement obligations settled during the applicable period.

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

		Years Ended December 31		
($ thousands)		**2022**		2021
Cash flows from operating activities	**$**	**1,172,872**	$	712,384
Change in non-cash working capital		**(26,072)**		26,582
Asset retirement obligations settled		**18,351**		6,662
Adjusted funds flow	**$**	**1,165,151**	$	745,628

<u>Advisory Regarding Oil and Gas Information</u>

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, 2022, which will be filed on February 23, 2023. 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. Of the 250 or more potential drilling locations currently identified in the Clearwater, as at December 31, 2022, 18 are proved locations, 17 are probable locations and the remainder are 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, 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.

	Three Months Ended December 31, 2022					Twelve Months Ended December 31, 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	10,991	10	40	11,383	12,938	10,766	10	35	11,753	12,770
Lloydminster	10,818	22	—	1,322	11,061	10,784	12	—	1,602	11,064
Peavine	11,009	—	—	—	11,009	7,442	—	—	—	7,442
Canada - Light										
Viking	—	12,540	192	11,359	14,625	—	14,052	189	11,990	16,239
Duvernay	—	1,290	1,172	3,575	3,058	—	1,247	887	2,811	2,603
Remaining Properties	—	649	554	18,314	4,255	—	739	785	21,798	5,157
United States										
Eagle Ford	—	17,594	5,703	39,726	29,918	—	17,041	5,679	33,146	28,245
Total	32,819	32,105	7,661	85,679	86,864	28,993	33,101	7,575	83,101	83,519

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", "net asset value", and "reserves life index." 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 reserve 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 reserve 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

Net asset value has been calculated based on the estimated net present value of all future net revenue from our reserves, before income taxes, as estimated by McDaniel effective December 31, 2022, plus the estimated value of our undeveloped land holdings, less net debt.

Reserve life index means the reserves for the particular reserve category divided by annualized 2022 fourth quarter production.

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 84% 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:

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