BAYTEX ANNOUNCES FOURTH QUARTER AND YEAR-END 2021 RESULTS, RESERVES AND RETURN OF CAPITAL FRAMEWORK

CALGARY, ALBERTA (February 24, 2022) - Baytex Energy Corp. ("Baytex")(TSX: BTE) reports its operating and financial results for the three months and year ended December 31, 2021 (all amounts are in Canadian dollars unless otherwise noted).

“In 2021, we made a commitment to maintain capital discipline, maximize free cash flow and reduce our net debt. I am very pleased to say we delivered on all fronts with strong operational execution, record free cash flow and a significantly improved balance sheet. With continued operating momentum and current commodity prices, we expect to generate over $550 million of free cash flow in 2022 and reach our initial $1.2 billion net debt target during the second quarter. As a result, we are announcing the next phase of our return of capital framework, which includes allocating approximately 25% of our free cash flow to share buybacks commencing in the second quarter. We are also following up our success in the Clearwater where we now have four of the top five initial rate wells drilled to date in the play,” commented Ed LaFehr, President and Chief Executive Officer.

2021 Highlights

- Production exceeded the high end of guidance at 80,789 boe/d (82% oil and NGL) in Q4/2021 and 80,156 boe/d (82% oil and NGL) for the full-year 2021.
- Exploration and development expenditures totaled $74 million in Q4/2021, bringing aggregate spending for 2021 to $313 million, in line with guidance.
- Delivered adjusted funds flow[1] of $215 million ($0.38 per basic share) in Q4/2021 and $746 million ($1.32 per basic share) for 2021.
- Generated a record level of free cash flow[2] of $137 million ($0.24 per basic share) in Q4/2021 and $421 million ($0.75 per basic share) for 2021.
- Cash flows from operating activities was $241 million ($0.43 per basic share) in Q4/2021 and $712 million ($1.26 per basic share) for 2021.
- Reduced net debt[1] by 24% to $1.4 billion at year-end 2021, from $1.8 billion at year-end 2020.
- Drilled four of the top five wells to-date in the Clearwater play, with our two most recent wells at Peavine generating 30-day initial production rates of 921 bbl/d and 815 bbl/d, respectively.
- Reduced our GHG emissions intensity (tonnes of CO2e per boe) in 2021 by 11% over 2020 levels and have now achieved a 52% reduction, relative to our 2018 baseline.

Reserves Highlights

- Proved developed producing reserves increased by 7%, from 120 mmboe to 129 mmboe. Proved reserves total 278 mmboe (271 mmboe at year-end 2020) and proved plus probable reserves total 451 mmboe (462 mmboe at year-end 2020).
- Finding and development ("F&D") costs, including changes in future development costs (“FDC”), were $8.20/boe for PDP reserves, $17.67/boe for 1P reserves and $24.55/boe for 2P reserves.
- Generated a PDP recycle ratio of 4.5x and a 1P recycle ratio of 2.1x based on 2021 operating netback[1] of $36.52/boe.
- At year-end 2021, the present value of our reserves, discounted at 10% before tax, is estimated to be $5.1 billion ($3.3 billion at year-end 2020). The increase is largely attributable to a higher commodity price forecast being utilized by our reserves evaluator (consultant average of approximately US$70/bbl WTI).
- Our net asset value at year-end 2021, discounted at 10% before tax, is estimated to be $6.67 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.

2022 Outlook

In 2022, we expect to benefit from our diversified oil weighted portfolio and our commitment to allocate capital effectively. Our capital program is designed to generate stable production from our light and heavy oil assets in Canada and the Eagle Ford in the United States, while scaling up development in the Clearwater.

Our 2022 guidance remains unchanged as we target production of 80,000 to 83,000 boe/d with exploration and development expenditures of $400 to $450 million. Based on the forward strip(1), we expect to generate over $550 million of free cash flow(2) in 2022.

	2022 Guidance
Exploration and development expenditures	$400 - $450 million
Production (boe/d)	80,000 - 83,000
Expenses:	
Average royalty rate (2)	18.5% - 19.0%
Operating (3)	$12.25 - $13.00/boe
Transportation (3)	$1.20 - $1.30/boe
General and administrative (3)	$43 million ($1.45/boe)
Interest (3)	$80 million ($2.70/boe)
Leasing expenditures	$3 million
Asset retirement obligations	$20 million

Return of Capital Framework

With continued operating momentum and strong commodity prices, we expect to reach our initial $1.2 billion net debt(4) target during the second quarter of 2022. As we reach this debt level, we will have reduced our net debt by approximately $1.1 billion over the past three and a half years. As a result of our significantly improved financial position, we are introducing the next phase of our enhanced return to shareholders framework.

For 2022, we expect to allocate approximately 25% of our annual free cash flow to direct shareholder returns and intend to implement a share buyback program commencing in Q2/2022.

The remainder of our free cash flow will continue to be allocated to debt reduction until we achieve a net debt level of $800 million, which represents an expected net debt(4) to EBITDA(5) ratio of 1.0x at a US$55 WTI price. We feel this level of net debt will provide us with ultimate flexibility to run our business through the commodity price cycles and generate meaningful returns for all stakeholders. At current prices, we expect to achieve this net debt level by mid-2023, at which point we will consider steps to further enhance shareholder returns.

(1) 2022 pricing assumptions: WTI - US$82/bbl; WCS differential - US$13/bbl; MSW differential – US$3/bbl, NYMEX Gas - US$4.80/mcf; AECO Gas - $4.50/mcf and Exchange Rate (CAD/USD) - 1.27.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Calculated as operating, transportation, general and administrative or interest expense divided by barrels of oil equivalent production volume for the applicable period.
(4) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(5) Calculated in accordance with the Credit Facilities Agreement.

	Three Months Ended			Twelve Months Ended	
	December 31, 2021	September 30, 2021	December 31, 2020	**December 31, 2021**	December 31, 2020
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 552,403**	$ 488,736	$ 233,636	**$ 1,868,195**	$ 975,477
Adjusted funds flow (1)	**214,766**	198,397	82,176	**745,628**	311,506
Per share – basic	**0.38**	0.35	0.15	**1.32**	0.56
Per share – diluted	**0.37**	0.35	0.15	**1.30**	0.56
Free cash flow (2)	**137,133**	101,215	1,794	**421,329**	18,073
Per share – basic	**0.24**	0.18	—	**0.75**	0.03
Per share – diluted	**0.24**	0.18	—	**0.74**	0.03
Cash flows from operating activities	**240,567**	178,961	51,017	**712,384**	353,096
Per share – basic	**0.43**	0.32	0.09	**1.26**	0.63
Per share – diluted	**0.42**	0.31	0.09	**1.25**	0.63
Net income (loss)	**563,239**	32,714	221,160	**1,613,600**	(2,438,964)
Per share – basic	**1.00**	0.06	0.39	**2.86**	(4.35)
Per share – diluted	**0.98**	0.06	0.39	**2.82**	(4.35)
Capital Expenditures					
Exploration and development expenditures	**$ 73,995**	$ 94,235	$ 77,809	**$ 313,303**	$ 280,340
Acquisitions and divestitures	**(5,414)**	(612)	(33)	**(6,247)**	(182)
Total oil and natural gas capital expenditures	**$ 68,581**	$ 93,623	$ 77,776	**$ 307,056**	$ 280,158
Net Debt					
Credit facilities	**$ 506,514**	$ 546,803	$ 651,173	**$ 506,514**	$ 651,173
Long-term notes	**885,920**	1,000,171	1,147,950	**885,920**	1,147,950
Long-term debt	**1,392,434**	1,546,974	1,799,123	**1,392,434**	1,799,123
Working capital deficiency	**17,283**	17,684	48,478	**17,283**	48,478
Net debt (1)	**$ 1,409,717**	$ 1,564,658	$ 1,847,601	**$ 1,409,717**	$ 1,847,601
Shares Outstanding - basic (thousands)					
Weighted average	**564,213**	564,211	561,173	**563,674**	560,657
End of period	**564,213**	564,213	561,227	**564,213**	561,227
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 77.19**	$ 70.56	$ 42.66	**$ 67.92**	$ 39.40
MEH oil (US$/bbl)	**78.89**	71.64	43.05	**69.26**	40.15
MEH oil differential to WTI (US$/bbl)	**1.70**	1.08	0.39	**1.34**	0.75
Edmonton par ($/bbl)	**93.29**	83.78	50.24	**80.23**	45.34
Edmonton par differential to WTI (US$/bbl)	**(3.15)**	(4.07)	(4.11)	**(3.92)**	(5.60)
WCS heavy oil ($/bbl)	**78.82**	71.81	43.46	**68.79**	35.95
WCS differential to WTI (US$/bbl)	**(14.63)**	(13.57)	(9.31)	**(13.05)**	(12.60)
Natural gas					
NYMEX (US$/mmbtu)	**$ 5.83**	$ 4.01	$ 2.66	**$ 3.84**	$ 2.08
AECO ($/mcf)	**4.94**	3.54	2.77	**3.56**	2.24
CAD/USD average exchange rate	**1.2600**	1.2601	1.3031	**1.2536**	1.3413

	Three Months Ended			Twelve Months Ended	
	December 31, 2021	September 30, 2021	December 31, 2020	**December 31, 2021**	December 31, 2020
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**34,986**	35,614	29,568	**35,789**	37,056
Heavy oil (bbl/d)	**23,482**	21,996	21,725	**22,188**	21,142
NGL (bbl/d)	**7,984**	7,174	6,495	**7,244**	7,340
Total liquids (bbl/d)	**66,452**	64,784	57,788	**65,221**	65,538
Natural gas (mcf/d)	**86,029**	90,528	76,116	**89,606**	85,464
Oil equivalent (boe/d @ 6:1) (3)	**80,789**	79,872	70,475	**80,156**	79,781
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 523,382**	$ 469,155	$ 222,745	**$ 1,782,506**	$ 927,096
Royalties	**(100,152)**	(90,523)	(37,807)	**(339,156)**	(163,735)
Operating expense	**(95,357)**	(84,196)	(79,748)	**(343,002)**	(331,345)
Transportation expense	**(8,169)**	(7,818)	(6,692)	**(32,261)**	(28,437)
Operating netback (2)	**$ 319,704**	$ 286,618	$ 98,498	**$ 1,068,087**	$ 403,579
General and administrative	**(11,481)**	(9,980)	(9,314)	**(40,804)**	(34,268)
Cash financing and interest	**(21,319)**	(22,793)	(25,194)	**(92,069)**	(106,534)
Realized financial derivatives (loss) gain	**(70,544)**	(53,905)	17,105	**(184,241)**	47,836
Other (4)	**(1,594)**	(1,543)	1,081	**(5,345)**	893
Adjusted funds flow (1)	**$ 214,766**	$ 198,397	$ 82,176	**$ 745,628**	$ 311,506
Netback per boe (5)					
Total sales, net of blending and other expense (2)	**$ 70.42**	$ 63.85	$ 34.35	**$ 60.93**	$ 31.75
Royalties	**(13.47)**	(12.32)	(5.83)	**(11.59)**	(5.61)
Operating expense	**(12.83)**	(11.46)	(12.30)	**(11.72)**	(11.35)
Transportation expense	**(1.10)**	(1.06)	(1.03)	**(1.10)**	(0.97)
Operating netback (2)	**$ 43.02**	$ 39.01	$ 15.19	**$ 36.52**	$ 13.82
General and administrative	**(1.54)**	(1.36)	(1.44)	**(1.39)**	(1.17)
Cash financing and interest	**(2.87)**	(3.10)	(3.89)	**(3.15)**	(3.65)
Realized financial derivatives (loss) gain	**(9.49)**	(7.34)	2.64	**(6.30)**	1.64
Other (4)	**(0.23)**	(0.21)	0.17	**(0.19)**	0.03
Adjusted funds flow (1)	**$ 28.89**	$ 27.00	$ 12.67	**$ 25.49**	$ 10.67

Notes:

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

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

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

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

(5) Calculated as royalties, operating or transportation expense divided by barrels of oil equivalent production volume for the applicable period.

2021 Results

In 2021, we delivered strong operating and financial results and continued to advance our exciting new Clearwater play in northwest Alberta with four of the highest initial rate wells drilled to date in the play. We also delivered on our commitment to maintain capital discipline, maximize free cash flow and reduce our net debt. Production exceeded the high end of our annual guidance and we generated record free cash flow[(1)] of $421 million, which meaningfully accelerated our debt reduction efforts.

Production during the fourth quarter averaged 80,789 boe/d (82% oil and NGL), as compared to 79,872 boe/d (82% oil and NGL) in Q3/2021. The higher volumes largely reflect a resumption of activity during the second half of the year. Production in 2021 averaged 80,156 boe/d as compared to 79,781 boe/d in 2020. Exploration and development expenditures totaled $74 million in Q4/2021 and $313 million for full-year 2021. We participated in the drilling of 231 (174.2 net) wells with a 100% success rate during the year.

We delivered adjusted funds flow[(2)] of $215 million ($0.38 per basic share) in Q4/2021 and $746 million ($1.32 per basic share) in 2021. This resulted in a record level of free cash flow of $137 million ($0.24 per basic share) in Q4/2021 and $421 million ($0.75 per basic share) in 2021. We allocated 100% of our free cash flow to debt repayment, reducing net debt[(2)] by 24% to $1.4 billion at year-end 2021, from $1.8 billion at year-end 2020.

We recorded net income of $563 million ($1.00 per basic share) in Q4/2021 and $1.6 billion ($2.86 per basic share) in 2021. During 2021, we identified indicators of impairment reversal for our oil and gas properties due to the increase in forecasted commodity prices. As a result, we recorded an impairment reversal of $0.4 billion in Q4/2021 and $1.5 billion for the full-year 2021 as the estimated recoverable amounts exceeded the carrying value of our oil and gas properties.

The following table compares our 2021 results to our 2021 guidance.

	2021 Guidance		
	Original [(3)]	**Revised [(4)]**	**2021 Results**
Exploration and development expenditures	$225 - $275 million	$285 - $315 million	$313 million
Production (boe/d)	73,000 - 77,000	77,000 - 79,000	80,156
Expenses:			
Average royalty rate [(1)]	18.0% - 18.5%	18.0% - 18.5%	19.0 %
Operating [(5)]	$11.50 - $12.25/boe	$11.25 - $12.00/boe	$11.72/boe
Transportation [(5)]	$1.00 - $1.10/boe	$1.15 - $1.25/boe	$1.10/boe
General and administrative [(5)]	$42 million ($1.53/boe)	$42 million ($1.48/boe)	$41 million ($1.39/boe)
Interest [(5)]	$105 million ($3.84/boe)	$98 million ($3.46/boe)	$92 million ($3.15/boe)
Leasing expenditures	$4 million	$4 million	$4 million
Asset retirement obligations [(6)]	$6 million	$6 million	$7 million

Operating Results

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 30,428 boe/d (82% oil and NGL) during Q4/2021 and 30,731 boe/d for the full-year 2021. In 2021, we invested $105 million on exploration and development in the Eagle Ford and generated an operating netback[(1)] of $437 million. During 2021, we participated in the drilling of 67 (15.5 net) wells and brought 93 (23.1 net) wells onstream. We expect to bring approximately 14 net wells onstream in 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.
(3) As announced on December 2, 2020.
(4) As announced on April 29, 2021. This guidance reference date included the introduction of a five-year outlook. 2021 guidance was subsequently tightened on November 4, 2021 reflecting year-to-date results to $300 to $315 million for exploration and development expenditures, 79,500 to 80,000 boe/d for production, 18.5% to 19.0% for average royalty rates, $11.25/boe to $11.75/boe for operating expenses, $1.10/boe to $1.15/boe for transportation expenses and $92 million ($3.16/boe) for interest expense.
(5) Calculated as operating, transportation, general and administrative or interest expense divided by barrels of oil equivalent production volume for the applicable period.
(6) Government grants reduced asset retirement obligations by $3 million in 2021.

Production in the Viking averaged 16,313 boe/d (88% oil and NGL) during Q4/2021 and 17,278 boe/d for the full-year 2021. In 2021, we invested $116 million on exploration and development in the Viking and generated an operating netback(1) of $327 million. During 2021, we participated in the drilling of 123 (121.2 net) wells and brought 116 (114.2 net) wells onstream. We expect to bring approximately 145 net wells onstream in 2022.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster (excluding our Clearwater development) produced a combined 24,217 boe/d (91% oil and NGL) during Q4/2021 and 23,579 boe/d for the full-year 2021. Our 2021 drilling program was heavily weighted to H2/2021 and included three net Bluesky wells at Peace River and 21.5 net wells at Lloydminster. In 2021, we invested $38 million on exploration and development in Peace River and Lloydminster and generated an operating netback(1) of $231 million. In 2022, we will drill approximately nine net Bluesky wells at Peace River and 37 net wells at Lloydminster.

Peace River Clearwater

We are committed to building and maintaining respectful relationships with Indigenous communities and creating opportunities for meaningful economic participation and inclusion. We have executed two strategic agreements with the Peavine Métis Settlement in the Peace River area that cover 80 sections of land directly to the south of our existing Seal operations. At the time, we identified potential for an early stage exploratory play targeting the Spirit River formation, a Clearwater formation equivalent. When combined with our legacy acreage position in northwest Alberta, we estimate that over 125 sections are highly prospective for Clearwater development.

Our 2021 appraisal program yielded exceptional results with production increasing from zero at the beginning of 2021 to over 3,000 bbl/d in January 2022. Our two eight-lateral wells (6-31 and 14-31) drilled during the fourth quarter and offsetting our highest initial rate well (11-31) generated 30-day initial production rates of 921 bbl/d and 815 bbl/d, respectively. With the performance of these two wells, our Peavine development has now yielded four of the top five initial rate Clearwater wells drilled-to date across the entire play. In addition, our eight lateral appraisal well (14-11) drilled on our northern acreage generated a very economic initial production rate (through its first twenty-five days of production) of approximately 120 bbl/d, consistent with our expectations. On our Seal legacy lands, we drilled a successful exploration well in late 2021 with a 30-day initial production rate of 147 bbl/d and we have a follow-up well scheduled for H2/2022.

The following table summarizes the results of our 2021 appraisal program.

Area	**Well**	**Spud**	**Rig Release**	**# of Laterals**	**30-Day Initial Production Rate (bbl/d) (2)**
Peavine	100/04-34	January 7	January 15	2	175
Peavine	102/04-34	June 15	June 21	2	175
Peavine	100/13-27	June 22	July 6	8	695
Peavine	100/05-34	July 8	July 18	8	412
Peavine	102/11-31	July 20	August 4	8	930
Peavine	100/06-31	November 4	November 15	8	921
Peavine	100/14-31	November 17	November 27	8	815
Peavine	100/14-11	November 29	December 11	8	120
Seal	100/12-34	October 21	November 2	6	147

Our first quarter 2022 drilling program is underway with two rigs that will see ten wells drilled on our Peavine lands. Importantly, we have successfully executed our first three extended reach horizontal multi-lateral wells at Peavine, which are utilized to provide appropriate set-backs to residents and environmentally sensitive areas. In aggregate, we expect to bring 18 wells onstream this year. To-date, we have de-risked 20 sections of land and pending further success, the play holds the potential for greater than 200 locations. The Clearwater generates strong economics with the ability to grow organically while enhancing our free cash flow profile.

Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 2,668 boe/d (83% oil and NGL) during Q4/2021 and 2,008 boe/d for the full-year 2021. The increased volumes during the fourth quarter reflect two wells brought onstream in October 2021. As a follow-up to our 2021 program, we are currently drilling a three-well pad which is expected to be onstream in Q3/2022.

(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) 30-Day Initial Production Rate (bbl/d) is defined as the average oil rate over the first 720 hours of production following drilling fluid recovery.

Financial Liquidity

Our credit facilities total approximately $1.0 billion and have a maturity date of April 2, 2024. These are not borrowing base facilities and do not require annual or semi-annual reviews. As of December 31, 2021, we had $506 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $489 million.

Our net debt[(1)], which includes our credit facilities, long-term notes and working capital, totaled $1.4 billion at December 31, 2021, down from $1.6 billion at September 30, 2021.

During 2021, we repurchased and cancelled US$200 million of the 5.625% long term notes due June 2024. This represents 50% of the original US$400 million outstanding.

Risk Management

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

For 2022, we have entered into hedges on approximately 41% of our net crude oil exposure utilizing a combination of a 3-way option structure that provides price protection at US$57.76/bbl with upside participation to US$67.51/bbl and swaptions at US$53.50/bbl. We also have WTI-MSW differential hedges on approximately 25% of our expected net Canadian light oil exposure at US$4.43/bbl and WCS differential hedges on approximately 70% of our expected net heavy oil exposure at a WTI-WCS differential of approximately US$12.28/bbl.

For 2023, we have entered into hedges on approximately 9% of our net crude oil exposure utilizing a 3-way option structure that provides price protection at US$71.00/bbl with upside participation to US$88.18/bbl

A complete listing of our financial derivative contracts can be found in Note 17 to our 2021 financial statements.

Environmental Stewardship

The energy industry and society are undergoing a transition to a low-carbon economy. We believe oil and gas will be instrumental in this energy transition. 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 decarbonization strategies.

In 2019, we established a GHG emissions reduction target. Our objective was to reduce our corporate GHG emission intensity (tonnes of CO2e per boe) by 30% by 2021, relative to our 2018 baseline. We exceeded this target in scope and timing, achieving a 46% reduction in our GHG emissions intensity through year-end 2020. This represented an annual reduction of 1.6 million tonnes of CO2e and was equivalent to taking 340,000 cars off the road annually.

Continual improvement is an important element of our corporate culture and we have set the bar higher. Our target is to now reduce our corporate GHG emission intensity by a further 33% from 2020 levels by 2025. This equates to an approximate 65% reduction by 2025, relative to our 2018 baseline. Our emissions reduction strategy includes increased gas conservation and combustion, reusing associated gas as fuel for field activities, reducing emissions from storage tanks, along with monitoring and preventing fugitive emissions.

In 2021, we reduced our GHG emissions intensity by 11% over 2020 levels. In 2022, we will invest approximately $10 million as part of our GHG mitigation program and expect to reduce our GHG emissions intensity by approximately 7.5% over 2021 levels.

GHG Emissions Intensity (Scope 1 and Scope 2)

	2018 Baseline	**2019**	**2020**	**2021**	**2025 Target**
Tonnes CO_2e/boe	0.112	0.095	0.061	0.054	0.041

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

Our commitment to responsible development also extends to the retirement of our assets. We plan for full lifecycle development of our properties which includes the restoration, abandonment and reclamation of assets that have reached the end of their productive 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 a proactive stance to managing future financial obligations and regulatory compliance. In 2022, we will embark on an active abandonment and reclamation program with approximately $35 million being directed to pipeline, wellbore and facility decommissioning along with well site reclamations.

Abandonment and Reclamation

	2018	2019	2020	2021	2022 Plan
Number of wells abandoned (gross)	110	113	99	237	320
Spending in abandonment/reclamation ($ million) (1)	$ 14	$ 15	$ 9	$ 10	$ 35

Year-end 2021 Reserves

Baytex's year-end 2021 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, 2022. Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2021, which will be filed on or before March 31, 2022.

Reserves Highlights

- Proved developed producing ("PDP") reserves increased by 7%, from 120 mmboe to 129 mmboe. Proved reserves ("1P") total 278 mmboe (271 mmboe at year-end 2020) and proved plus probable reserves ("2P") total 451 mmboe (462 mmboe at year-end 2020).
- Finding and development ("F&D") costs, including changes in future development costs ("FDC"), were $8.20/boe for PDP reserves, $17.67/boe for 1P reserves and $24.55/boe for 2P reserves.
- Generated a PDP recycle ratio of 4.5x and a 1P recycle ratio of 2.1x based on 2021 operating netback(2) of $36.52/boe.
- Reserves on a 1P basis are comprised of 80% oil and NGL (36% light oil, 26% NGL's, 17% heavy oil and 2% bitumen) and 20% natural gas. PDP reserves represent 46% of 1P reserves (44% at year-end 2020) and 1P reserves represent 62% of 2P reserves (59% at year-end 2020).
- Baytex maintains a strong reserves life index of 4.4 years based on PDP reserves, 9.4 years based on 1P reserves and 15.3 years based on 2P reserves.
- At year-end, 2021, the present value of our reserves, discounted at 10% before tax, is estimated to be $5.1 billion ($3.3 billion at year-end 2020). The increase is largely attributable to a higher commodity price forecast being utilized by our reserves evaluator (consultant average of approximately US$70/bbl WTI).
- Our net asset value at year-end 2021, discounted at 10% before tax, is $6.67 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) Spending includes government grants received for abandonment and reclamations of $2 million in 2020, $3 million in 2021 and $15 million in 2022.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.

The following table sets forth our gross and net reserves volumes at December 31, 2021 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	18,564	26,623	23,735	641	69,564	31,853	65,234	99,778	128,919
Proved developed non-producing	664	314	765	—	1,743	852	1,973	2,448	3,333
Proved undeveloped	26,781	26,278	21,503	4,197	78,759	39,431	37,216	129,213	145,929
Total proved	46,009	53,216	46,003	4,838	150,067	72,137	104,423	231,439	278,181
Total probable	23,296	21,485	29,705	45,874	120,360	27,751	62,394	84,928	172,665
Proved plus probable	69,305	74,701	75,709	50,713	270,427	99,888	166,817	316,367	450,846
Net (2)									
Proved producing	17,436	19,797	20,775	575	58,583	23,735	58,749	74,461	104,519
Proved developed non-producing	617	232	689	—	1,538	630	1,687	1,812	2,751
Proved undeveloped	24,891	19,882	19,139	3,857	67,769	29,521	34,310	96,601	119,108
Total proved	42,944	39,911	40,602	4,432	127,890	53,885	94,745	172,874	226,378
Total probable	21,399	16,404	25,547	37,186	100,535	20,970	56,747	64,506	141,715
Proved plus probable	64,343	56,315	66,149	41,618	228,425	74,856	151,492	237,381	368,093

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, 2020	52,067	53,316	35,412	5,737	146,532	72,475	87,894	226,334	271,378
Extensions	3,227	4,370	8,977	—	16,574	4,294	16,032	16,165	26,234
Technical Revisions [(2)]	(6,059)	520	2,949	(394)	(2,984)	(1,379)	(1,649)	1,599	(4,372)
Acquisitions	3	—	1,228	—	1,231	—	—	—	1,231
Dispositions	(2)	(20)	(260)	—	(282)	(19)	(313)	(35)	(360)
Economic Factors	2,509	612	5,160	130	8,411	1,159	20,547	1,995	13,326
Production	(5,734)	(5,581)	(7,464)	(635)	(19,414)	(4,392)	(18,088)	(14,619)	(29,257)
December 31, 2021	46,009	53,216	46,003	4,838	150,067	72,137	104,423	231,439	278,181

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, 2020	25,688	24,642	30,544	46,093	126,967	32,760	86,778	96,852	190,332
Extensions	2,413	(2,315)	(760)	—	(663)	(2,989)	(9,810)	(10,055)	(6,963)
Technical Revisions [(2)]	(5,357)	(1,018)	(1,721)	(216)	(8,312)	(1,634)	(70)	(2,403)	(10,359)
Acquisitions	—	—	458	—	458	—	—	—	458
Dispositions	(5)	(5)	(225)	—	(235)	(258)	(7,224)	(9)	(1,699)
Economic Factors	556	182	1,409	(2)	2,145	(127)	(7,280)	543	895
Production	—	—	—	—	—	—	—	—	—
December 31, 2021	23,296	21,485	29,705	45,874	120,360	27,751	62,394	84,928	172,665

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, 2020	77,755	77,958	65,956	51,830	273,499	105,235	174,671	323,186	461,710
Extensions	5,640	2,054	8,217	—	15,911	1,304	6,222	6,110	19,271
Technical Revisions [(2)]	(11,416)	(498)	1,228	(610)	(11,296)	(3,013)	(1,719)	(804)	(14,730)
Acquisitions	3	—	1,686	—	1,689	—	—	—	1,689
Dispositions	(7)	(26)	(485)	—	(517)	(278)	(7,536)	(45)	(2,058)
Economic Factors	3,065	794	6,570	127	10,556	1,031	13,267	2,538	14,221
Production	(5,734)	(5,581)	(7,464)	(635)	(19,414)	(4,392)	(18,088)	(14,619)	(29,257)
December 31, 2021	69,305	74,701	75,709	50,713	270,427	99,888	166,817	316,367	450,846

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 revisions in light and medium oil are predominantly associated with our Viking asset and due to variations in performance versus previous forecasts and the removal of inventory locations with higher finding and development costs.

(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
2022	416	423
2023	506	540
2024	517	562
2025	489	581
2026	398	657
Remainder	84	987
Total FDC undiscounted	2,410	3,750

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		2021		2020		2019		3 Year
Proved plus Probable Reserves								
Finding & Development Costs								
Exploration and development expenditures	$	313.3	$	280.3	$	552.3	$	1,145.9
Net change in Future Development Costs	$	147.4	$	(705.9)	$	96.7	$	(461.8)
Gross Reserves additions (mmboe)		18.8		(38.4)		39.8		20.2
F&D Costs ($/boe)	$	24.55	$	11.08	$	16.30	$	33.92
Finding, Development & Acquisition (“FD&A”) Costs								
Exploration and development expenditures and net acquisitions	$	307.1	$	280.2	$	554.5	$	1,141.7
Net change in Future Development Costs	$	144.4	$	(709.3)	$	79.9	$	(485.0)
Gross Reserves additions (mmboe)		18.4		(38.6)		38.6		18.5
FD&A Costs ($/boe)	$	24.55	$	11.12	$	16.42	$	35.59
Proved Reserves								
Finding & Development Costs								
Exploration and development expenditures	$	313.3	$	280.3	$	552.3	$	1,145.9
Net change in Future Development Costs	$	308.6	$	(464.4)	$	(90.4)	$	(246.2)
Gross Reserves additions (mmboe)		35.2		(13.1)		35.8		57.9
F&D Costs ($/boe)	$	17.67	$	14.06	$	12.92	$	15.55
Finding, Development & Acquisition Costs								
Exploration and development expenditures and net acquisitions	$	307.1	$	280.2	$	554.5	$	1,141.7
Net change in Future Development Costs	$	316.8	$	(464.4)	$	(107.2)	$	(254.7)
Gross Reserves additions (mmboe)		36.1		(13.1)		34.7		57.7
FD&A Costs ($/boe)	$	17.30	$	14.07	$	12.88	$	15.38
Proved Developed Producing Reserves								
Finding & Development Costs								
Exploration and development expenditures	$	313.3	$	280.3	$	552.3	$	1,145.9
Gross Reserves additions (mmboe)		38.2		7.7		42.5		88.2
F&D Costs ($/boe)	$	8.20	$	36.63	$	13.04	$	12.99
Finding, Development & Acquisition Costs								
Exploration and development expenditures and net acquisitions	$	307.1	$	280.2	$	554.5	$	1,141.7
Gross Reserves additions (mmboe)		38.1		7.6		42.5		88.3
FD&A Costs ($/boe)	$	8.06	$	36.64	$	13.04	$	12.93

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 2021 by annualized Q4/2021 production.

		Reserves Life Index (years)	
	Q4/2021 Production	Proved	Proved Plus Probable
Crude Oil and NGL (bbl/d)	66,452	9.2	15.3
Natural Gas (mcf/d)	86,029	10.7	15.4
Oil Equivalent (boe/d)	80,789	9.4	15.3

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, 2021. 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, 2022.

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
2021 act.	67.95	80.25	68.80	3.90	3.55	1.4	0.800
2022	72.83	86.82	74.42	3.85	3.56	—	0.797
2023	68.78	80.73	69.17	3.44	3.21	2.3	0.797
2024	66.76	78.01	66.54	3.17	3.05	2.0	0.797
2025	68.09	79.57	67.87	3.24	3.11	2.0	0.797
2026	69.45	81.16	69.23	3.30	3.17	2.0	0.797
2027	70.84	82.78	70.61	3.37	3.23	2.0	0.797
2028	72.26	84.44	72.02	3.44	3.30	2.0	0.797
2029	73.70	86.13	73.46	3.50	3.36	2.0	0.797
2030	75.18	87.85	74.69	3.58	3.43	2.0	0.797
2031	76.68	89.61	76.19	3.65	3.50	2.0	0.797
Thereafter		Escalation rate of 2.0%				2.0	0.797

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, 2021 ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	2,399	2,235	1,988	1,787
Proved developed non-producing	94	72	60	52
Proved undeveloped	2,852	1,948	1,399	1,040
Total proved	5,345	4,255	3,448	2,880
Probable	4,596	2,554	1,636	1,149
Total Proved Plus Probable (before tax)	9,941	6,809	5,084	4,029

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 does not consider "going concern" value and 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, 2021.

($ millions, except per share amounts, discounted at)	5%	10%	15%
Net present value of proved plus probable reserves (1)	6,809	5,084	4,029
Undeveloped land holdings (2)	89	89	89
Net Debt (4)	(1,410)	(1,410)	(1,410)
Net Asset Value	5,488	3,763	2,708
Net Asset Value per Share (3)	9.73	6.67	4.80

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) Based on 564.2 million common shares outstanding as at December 31, 2021.
(4) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.

Additional Information

Our audited consolidated financial statements for the year ended December 31, 2021 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

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

Baytex will host a conference call tomorrow, February 25, 2022, 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/baytex20220225.html in your web browser.

An archived recording of the conference call will be available shortly after the event by accessing the webcast link above. The conference call will also be archived on the Baytex website at www.baytexenergy.com.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this press release are "forward-looking statements" within the meaning of the United States Private Securities Litigation Reform Act of 1995 and "forward-looking information" within the meaning of applicable Canadian securities legislation (collectively, "forward-looking statements"). In some cases, forward-looking statements can be identified by terminology such as "believe", "continue", ""estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this press release speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this press release contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that we expect to generate more than $550 million of free cash flow in 2022 and reach our $1.2 billion net debt target in Q2/2022; the next phase of our return of capital frame work, which includes allocating 25% of free cash flow to share buy backs starting in Q2/2022; in 2022 that: we expect to benefit from our diversified oil weighted portfolio and a commitment to allocate capital effectively and our program is designed to generate stable production while scaling up development in the Clearwater; our guidance for 2022 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; we expect to allocate 25% of free cash flow to share buy backs starting in Q2/2022 with the remainder of our free cash flow allocated to debt repayment until we achieve a net debt level of $800 million, our expected net debt to EBITDA ratios at such net debt level at $US55 WTI and $US75 WTI and our expectation that we will achieve that net debt level by mid-2023 at which point we will consider enhanced shareholder returns; in the Eagle Ford that we expect to bring 14 net wells onstream in 2022; in the Viking that we expect to bring 145 nets wells onstream in 2022; in 2022, that we will drill ~9 net Bluesky wells at Peace River and 37 net wells at Lloydminster; we have 125 sections that are highly prospective for Clearwater development; we have a follow-up Clearwater well scheduled on our legacy Seal lands in H2/2022; we are drilling 10 wells in Q1/2022 on our Peavine lands and expect to bring 18 wells onstream in 2022; our Clearwater play holds the potential for greater than 200 locations, has strong economics and the ability to grow organically while enhancing free cash flow; in Duvernay that we are drilling a three well pad expected to be onstream in Q3/2022; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility, the percentage of our expected production in 2022 of Canadian light oil and heavy oil for which we have hedged the differential to WTI and the percentage of our 2022 and 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 2022 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 2022 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: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax, carbon tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; results of litigation; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control.

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2021, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2022 and in our other public filings.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

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

Specified Financial Measures

In this press release, we refer to certain financial measures (such as free cash flow, operating netback, average royalty rate and total sales, net of blending and other expense) which do not have any standardized meaning prescribed by IFRS. While free cash flow and operating netback are commonly used in the oil and gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers. In addition, this press release contains the terms adjusted funds flow and net debt, which are considered capital management measures.

Non-GAAP Financial Measures

Total sales, net of blending and other expense

Total sales, net of blending and other expense is not a measurement based on GAAP in Canada and represents the revenues realized from produced volumes during a period. Total sales, net of blending and other expense is comprised of total petroleum and natural gas sales adjusted for blending and other expense. We believe including the blending and other expense associated with purchased volumes is useful when analyzing our realized pricing for produced volumes against benchmark commodity prices.

Operating netback

Operating netback is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. Operating netback is equal to petroleum and natural gas sales less blending expense, royalties, production and operating expense and transportation expense. Our determination of operating netback may not be comparable with the calculation of similar measures for other entities. We believe that this measure assists in characterizing our ability to generate cash margin on a unit of production basis and is a key measure used to evaluate our operating performance.

The following table reconciles total sales, net of blending and other expense and operating netback to petroleum and natural gas sales.

	Years Ended December 31	
($ thousands)	**2021**	2020
Petroleum and natural gas sales	**$ 1,868,195**	$ 975,477
Blending and other expense	**(85,689)**	(48,381)
Total sales, net of blending and other expense	**1,782,506**	927,096
Royalties	**(339,156)**	(163,735)
Operating expense	**(343,002)**	(331,345)
Transportation expense	**(32,261)**	(28,437)
Operating netback	**1,068,087**	403,579

Free cash flow

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as cash flows from operating activities adjusted for changes in non-cash working capital, additions to exploration and evaluation assets, additions to oil and gas properties and payments on lease obligations. Our determination of free cash flow may not be comparable to other issuers. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities.
Free cash flow is reconciled to cash flows from operating activities in the following table.

	Years Ended December 31	
($ thousands)	**2021**	2020
Cash flows from operating activities	**$ 712,384**	$ 353,096
Change in non-cash working capital	**26,582**	(48,758)
Additions to exploration and evaluation assets	**(3,298)**	(4,490)
Additions to oil and gas properties	**(310,005)**	(275,850)
Payments on lease obligations	**(4,334)**	(5,925)
Free cash flow	**$ 421,329**	$ 18,073

Non-GAAP Financial Ratios

Total sales, net of blending and other expense per boe

Total sales, net of blending and other per boe is used to compare our realized pricing to applicable benchmark prices and is calculated as total sales, net of blending and other expense divided by barrels of oil equivalent production volume for the applicable period.

Average royalty rate

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

Operating netback per boe

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

Capital Management Measures

Net debt

We define net debt to be the sum of our credit facilities and long-term notes outstanding adjusted for unamortized debt issuance costs, trade and other payables, cash and trade and other receivables. Our definition of net debt may not be comparable to other issuers. We believe that this measure assists in providing a more complete understanding of our cash liabilities and provides a key measure to assess our liquidity. We use the principal amounts of the credit facilities and long-term notes outstanding in the calculation of net debt as these amounts represent our ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the credit facilities and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of capital or repayment obligation.

The following table summarizes our calculation of net debt.

($ thousands)	**December 31, 2021**	December 31, 2020
Credit facilities	**$ 505,171**	$ 649,221
Unamortized debt issuance costs - Credit facilities(1)	**1,343**	1,952
Long-term notes	**874,527**	1,132,868
Unamortized debt issuance costs - Long-term notes(1)	**11,393**	15,082
Trade and other payables	**190,692**	155,955
Trade and other receivables	**(173,409)**	(107,477)
Net debt	**$ 1,409,717**	$ 1,847,601

(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, 2021.

Adjusted funds flow

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

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

	Years Ended December 31	
($ thousands)	**2021**	2020
Cash flows from operating activities	**$ 712,384**	$ 353,096
Change in non-cash working capital	**26,582**	(48,758)
Asset retirement obligations settled	**6,662**	7,168
Adjusted funds flow	**$ 745,628**	$ 311,506

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, 2021, which will be filed on or before March 31, 2022. 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.*

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

	Three Months Ended December 31, 2021					Twelve Months Ended December 31, 2021				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	11,491	8	22	11,027	13,359	11,198	7	23	11,408	13,130
Lloydminster	10,566	12	—	1,677	10,858	10,202	6	—	1,448	10,449
Peavine	1,425	—	—	—	1,425	788	—	—	—	788
Canada - Light										
Viking	—	14,200	166	11,679	16,313	—	15,277	146	11,133	17,278
Duvernay	—	1,475	733	2,766	2,668	—	1,047	598	2,178	2,008
Remaining Properties	—	693	792	25,524	5,739	—	606	904	25,566	5,771
United States										
Eagle Ford	—	18,598	6,271	33,356	30,428	—	18,846	5,573	37,874	30,731
Total	23,482	34,986	7,984	86,029	80,789	22,188	35,789	7,244	89,606	80,156

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, 2021, 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 2021 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 82% of Baytex's production is weighted toward crude oil and natural gas liquids. Baytex's common shares trade on the Toronto Stock Exchange under the symbol BTE.

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

Brian Ector, Vice President, Capital Markets

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