Q2 REPORT

2022

TSX BTE

BAYTEX ANNOUNCES SECOND QUARTER 2022 RESULTS, RECORD QUARTERLY FREE CASH FLOW, UPDATED SHAREHOLDER RETURN FRAMEWORK AND PLANNED CEO RETIREMENT

CALGARY, ALBERTA (July 27, 2022) - Baytex Energy Corp. ("Baytex")(TSX: BTE) reports its operating and financial results for the three and six months ended June 30, 2022 (all amounts are in Canadian dollars unless otherwise noted).

“During the second quarter, we delivered strong operating results which included significant production growth from our Clearwater assets and record quarterly free cash flow of $245 million. Given the strength of our balance sheet and consistent with our desire to offer direct shareholder returns, we launched our share buyback program in May and repurchased 9.1 million shares during the quarter. I am also excited to announce that upon hitting our $800 million net debt target in late 2022 or early 2023, we anticipate increasing direct shareholder returns to 50% of our free cash flow and accelerating our share buyback program. We continue to view our shares as undervalued in relation to our current operations," commented Ed LaFehr, President and Chief Executive Officer.

Q2 2022 Highlights

- Generated production of 83,090 boe/d (83% oil and NGL) in Q2/2022, a 2% increase over Q2/2021.
- Delivered adjusted funds flow[1] of $346 million ($0.61 per basic share) in Q2/2022, a 97% increase compared to $176 million ($0.31 per basic share) in Q2/2021.
- Generated free cash flow[2] of $245 million ($0.43 per basic share) in Q2/2022, a 118% increase compared to $112 million ($0.20 per basic share) in Q2/2021.
- Cash flows from operating activities of $360 million ($0.63 per basic share) in Q2/2022, a 109% increase compared to $172 million ($0.30 per basic share) in Q2/2021.
- Reduced net debt[1] by 20% to $1.12 billion, from $1.41 billion at year-end 2021.
- Redeemed the remaining US$200 million principal amount of 5.625% long-term notes at par on June 1, 2022.
- Repurchased 9.1 million common shares, representing 1.6% of our shares outstanding, at an average price of $6.88 per share.
- Generated production from our Clearwater play at Peavine of 7,319 bbl/d in Q2/2022, up from 3,154 bbl/d in Q1/2022. Production during the month of June averaged 9,088 bbl/d from 18 producing wells and we have 14 Clearwater wells to drill during the second half of 2022.

2022 Outlook

We remain intensely focused on maintaining capital discipline and driving meaningful free cash flow in our business. We continue to execute our 2022 plan with production guidance unchanged at 83,000 to 85,000 boe/d and expect to exit 2022 producing approximately 87,000 to 88,000 boe/d.

Our 2022 exploration and development expenditures guidance is unchanged at $450 to $500 million. We continue to experience inflationary pressures in our business, particularly the Eagle Ford, and anticipate full-year capital expenditures toward the high end of our guidance range. Based on the forward strip[3], we expect to generate approximately $700 million ($1.25 per basic share) of free cash flow this year.

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) 2022 full-year pricing assumptions: WTI - US$98/bbl; WCS differential - US$17/bbl; MSW differential – US$3/bbl, NYMEX Gas - US$6.60/mcf; AECO Gas - $5.80/mcf and Exchange Rate (CAD/USD) - 1.28.

2022 Outlook (continued)

We have fine-tuned several of our cost assumptions to reflect increased royalties due to higher commodity prices and further inflationary pressures on operating and transportation expenses, related to labor, fuel, electricity and hauling. We are now forecasting approximately 15% inflation on a combined basis for operating and transportation expenses, as compared to 2021.

The following table highlights our 2022 annual guidance.

	2022 Guidance (1)	2022 Revised Guidance
Exploration and development expenditures	$450 - $500 million	no change
Production (boe/d)	83,000 - 85,000	no change
Expenses:		
Average royalty rate (2)	20.0% - 20.5%	21.0% - 22.0%
Operating (3)	$13.00 - $13.50/boe	$13.75 - $14.25/boe
Transportation (3)	$1.30 - $1.40/boe	$1.50 - $1.60/boe
General and administrative (3)	$43 million ($1.40/boe)	no change
Interest (3)	$75 million ($2.45/boe)	no change
Leasing expenditures	$3 million	no change
Asset retirement obligations	$20 million	no change

Update to Shareholder Return Framework

With continued operating momentum and strong commodity prices, we reached our initial $1.2 billion net debt[4] target during Q2/2022.

Our improved financial position enabled us to implement the first phase of our enhanced shareholder return framework in May, allocating 25% of our annual free cash flow to a share buyback program. During the second quarter, we repurchased 9.1 million common shares, representing 1.6% of our shares outstanding, at an average price of $6.88 per share. The remainder of our free cash flow continues to be allocated to debt reduction.

As our deleveraging continues at a rapid pace, we are pleased to announce the second phase of our shareholder return framework. Upon hitting a net debt level of $800 million in late 2022 or early 2023, we anticipate increasing direct shareholder returns to 50% of our free cash flow and accelerating our share buyback program. We continue to view our shares as undervalued in relation to our current operations.

We have also established an ultimate net debt target for the company of $400 million, which represents an expected net debt[4] to EBITDA[5] ratio of 1.0x at a US$45 WTI price. We feel this level of net debt will provide us with full flexibility to run our business through the commodity price cycles and generate meaningful returns for our shareholders. At current prices, we expect to achieve this net debt level by the end of 2023 or early 2024, at which point we will consider steps to further enhance shareholder returns.

President and CEO Retirement

Mr. LaFehr has provided the company notice of his intent to retire in January 2023. Mr. LaFehr has had a long and successful career as an oil and gas executive. Over the last six years at Baytex he has stewarded the company through a challenging commodity price environment and positioned the company to deliver meaningful returns to shareholders.

(1) As announced on April 28, 2022.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Calculated as operating, transportation, general and administrative or cash interest expense divided by barrels of oil equivalent production volume for the applicable period.
(4) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(5) Calculated in accordance with the Credit Facilities Agreement.

“With a strong and improving balance sheet, our exciting Clearwater play and the initiation of share buybacks, Mr. LaFehr’s planned retirement comes at a time when Baytex has a solid foundation and is well positioned for the future. Mr. LaFehr will continue to lead the team in the execution of the 2022 plan and 2023 budget preparation, which will include advancing our shareholder return framework. In addition, we will benefit from Mr. LaFehr’s input as we progress through the CEO transition process,” commented Mark Bly, Chair of the Board.

“I am pleased that Baytex is extremely well positioned for the future and, at the same time, I am ready to move to the next stage of my career. I look forward to guiding the company through a smooth transition as we continue to build operational momentum and drive shareholder returns,” commented Ed LaFehr, President and Chief Executive Officer.

Executive development and succession planning are an ongoing process at Baytex and are critical responsibilities of the Board. To help facilitate this process, Baytex’s Board has established a succession committee and engaged an executive search firm to identify and evaluate both internal and external candidates for the role.

	Three Months Ended			Six Months Ended	
	June 30, 2022	March 31, 2022	June 30, 2021	**June 30, 2022**	June 30, 2021
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 854,169**	$ 673,825	$ 442,354	**$ 1,527,994**	$ 827,056
Adjusted funds flow (1)	**345,704**	279,607	175,883	**625,311**	332,465
Per share - basic	**0.61**	0.49	0.31	**1.10**	0.59
Per share - diluted	**0.60**	0.49	0.31	**1.10**	0.59
Free cash flow (2)	**245,316**	121,318	112,486	**366,634**	182,981
Per share – basic	**0.43**	0.21	0.20	**0.65**	0.32
Per share – diluted	**0.43**	0.21	0.20	**0.64**	0.32
Cash flows from operating activities	**360,034**	198,974	171,876	**559,008**	292,856
Per share – basic	**0.63**	0.35	0.30	**0.99**	0.52
Per share – diluted	**0.63**	0.35	0.30	**0.98**	0.52
Net income	**180,972**	56,858	1,052,999	**237,830**	1,017,647
Per share - basic	**0.32**	0.10	1.87	**0.42**	1.81
Per share - diluted	**0.32**	0.10	1.85	**0.42**	1.79
Capital Expenditures					
Exploration and development expenditures	**$ 96,633**	$ 153,822	$ 61,485	**$ 250,455**	$ 145,073
Acquisitions and divestitures	**194**	32	(18)	**226**	(221)
Total oil and natural gas capital expenditures	**$ 96,827**	$ 153,854	$ 61,467	**$ 250,681**	$ 144,852
Net Debt					
Credit facilities	**$ 496,917**	$ 426,858	$ 486,623	**$ 496,917**	$ 486,623
Long-term notes	**643,600**	873,880	1,109,211	**643,600**	1,109,211
Long-term debt	**1,140,517**	1,300,738	1,595,834	**1,140,517**	1,595,834
Working capital	**(17,220)**	(25,058)	33,795	**(17,220)**	33,795
Net debt (1)	**$ 1,123,297**	$ 1,275,680	$ 1,629,629	**$ 1,123,297**	$ 1,629,629
Shares Outstanding - basic (thousands)					
Weighted average	**566,997**	565,518	564,156	**566,262**	563,126
End of period	**560,139**	569,214	564,182	**560,139**	564,182
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 108.41**	$ 94.29	$ 66.07	**$ 101.35**	$ 61.96
MEH oil (US$/bbl)	**112.41**	96.72	67.15	**104.56**	63.26
MEH oil differential to WTI (US$/bbl)	**4.00**	2.43	1.08	**3.21**	1.30
Edmonton par ($/bbl)	**137.79**	115.66	77.28	**126.72**	71.93
Edmonton par differential to WTI (US$/bbl)	**(0.47)**	(2.94)	(3.13)	**(1.68)**	(4.28)
WCS heavy oil ($/bbl)	**122.05**	100.99	67.03	**111.48**	62.33
WCS differential to WTI (US$/bbl)	**(12.80)**	(14.53)	(11.48)	**(13.67)**	(11.98)
Natural gas					
NYMEX (US$/mmbtu)	**$ 7.17**	$ 4.95	$ 2.83	**$ 6.06**	$ 2.76
AECO ($/mcf)	**6.27**	4.59	2.85	**5.43**	2.89
CAD/USD average exchange rate	**1.2766**	1.2661	1.2279	**1.2714**	1.2471

	Three Months Ended			Six Months Ended	
	June 30, 2022	March 31, 2022	June 30, 2021	**June 30, 2022**	June 30, 2021
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**33,007**	34,065	37,134	**33,533**	36,286
Heavy oil (bbl/d)	**28,586**	25,236	21,269	**26,921**	21,627
NGL (bbl/d)	**7,468**	7,636	7,563	**7,552**	6,904
Total liquids (bbl/d)	**69,061**	66,937	65,966	**68,006**	64,817
Natural gas (mcf/d)	**84,169**	83,574	91,172	**83,873**	90,957
Oil equivalent (boe/d @ 6:1) (3)	**83,090**	80,867	81,162	**81,985**	79,978
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (2)	**$ 797,274**	$ 632,385	$ 422,387	**$ 1,429,659**	$ 789,969
Royalties	**(171,559)**	(122,720)	(81,531)	**(294,279)**	(148,481)
Operating expense	**(107,426)**	(100,766)	(82,901)	**(208,192)**	(163,449)
Transportation expense	**(11,758)**	(9,215)	(7,486)	**(20,973)**	(16,274)
Operating netback (2)	**$ 506,531**	**$ 399,684**	**$ 250,469**	**$ 906,215**	**$ 461,765**
General and administrative	**(11,640)**	(11,682)	(10,610)	**(23,322)**	(19,343)
Cash financing and interest	**(20,474)**	(20,427)	(23,554)	**(40,901)**	(47,957)
Realized financial derivatives loss	**(124,042)**	(84,366)	(39,024)	**(208,408)**	(59,792)
Other (4)	**(4,671)**	(3,602)	(1,398)	**(8,273)**	(2,208)
Adjusted funds flow (1)	**$ 345,704**	**$ 279,607**	**$ 175,883**	**$ 625,311**	**$ 332,465**
Netback (per boe) (5)					
Total sales, net of blending and other expense (2)	**$ 105.44**	$ 86.89	$ 57.19	**$ 96.34**	$ 54.57
Royalties	**(22.69)**	(16.86)	(11.04)	**(19.83)**	(10.26)
Operating expense	**(14.21)**	(13.85)	(11.22)	**(14.03)**	(11.29)
Transportation expense	**(1.56)**	(1.27)	(1.01)	**(1.41)**	(1.12)
Operating netback (2)	**$ 66.98**	**$ 54.91**	**$ 33.92**	**$ 61.07**	**$ 31.90**
General and administrative	**(1.54)**	(1.61)	(1.44)	**(1.57)**	(1.34)
Cash financing and interest	**(2.71)**	(2.81)	(3.19)	**(2.76)**	(3.31)
Realized financial derivatives loss	**(16.41)**	(11.59)	(5.28)	**(14.04)**	(4.13)
Other (4)	**(0.60)**	(0.48)	(0.20)	**(0.56)**	(0.15)
Adjusted funds flow (1)	**$ 45.72**	**$ 38.42**	**$ 23.81**	**$ 42.14**	**$ 22.97**

Notes:

(1) Capital management measure. Refer to the Specified Financial Measures section in this press release for further information.
(2) Specified financial measure that does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures presented by other entities. Refer to the Specified Financial Measures section in this press release for further information.
(3) Barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. The use of boe amounts may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
(4) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and cash share-based compensation. Refer to the Q2/2022 MD&A for further information on these amounts.
(5) Calculated as royalties, operating, transportation, general and administrative, cash financing and interest expense or realized financial derivatives loss divided by barrels of oil equivalent production volume for the applicable period.

Q2/2022 Results

In Q2/2022, we delivered strong operating and financial results and continued to advance our exciting new Clearwater play in northwest Alberta.

Production during the second quarter averaged 83,090 boe/d (83% oil and NGL) as compared to 80,867 boe/d (82% oil and NGL) in Q1/2022. The increased production is consistent with our full-year plan and reflects the success of our first quarter drilling program at Peavine, which more than offset the seasonality associated with spring breakup and wet weather conditions across western Canada.

Exploration and development expenditures totaled $97 million in Q2/2022 and we participated in the drilling of 37 (21.4 net) wells with a 100% success rate.

We delivered adjusted funds flow(1) of $346 million ($0.61 per basic share) and net income of $181 million ($0.32 per basic share). We generated a record level of quarterly free cash flow(2) of $245 million ($0.43 per basic share) and reduced net debt(1) by 12% to $1.12 billion, from $1.28 billion at March 31, 2022.

Operating Results

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 28,170 boe/d (82% oil and NGL) during Q2/2022 and generated an operating netback(2) of $168 million. We invested $45 million on exploration and development in the Eagle Ford during the quarter and brought 20 (3.8 net) wells onstream. We expect to bring approximately 18 net wells onstream in 2022.

Production in the Viking averaged 16,487 boe/d (87% oil and NGL) during Q2/2022 and generated an operating netback of $140 million. We invested $15 million on exploration and development in the Viking during the quarter and brought 9 (8.2 net) wells onstream. We expect to bring approximately 130 net wells onstream in 2022.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster (excluding our Clearwater development program) produced a combined 23,683 boe/d (90% oil and NGL) during Q2/2022 and generated an operating netback of $122 million. We invested $16 million on exploration and development during the quarter and brought onstream 3 net Bluesky wells at Peace River and 5.8 net wells at Lloydminster. In 2022, we will drill approximately 9 net Bluesky wells at Peace River and 31 net wells at Lloydminster.

Peace River Clearwater

Production in the Clearwater averaged 7,319 boe/d (100% oil) during Q2/2022 and generated an operating netback of $48 million. Production during the second quarter was curtailed by approximately 650 bbl/d due to spring break-up and road maintenance that led to the shut-in of our 4-25 pad for two weeks in May. Production during the month of June averaged 9,088 bbl/d from 18 producing wells.

We followed up our 2021 appraisal program on our Peavine acreage with an exceptional Q1/2022 drilling program. During the second quarter, the remaining four wells from our 10-well Q1/2022 drilling program were brought onstream and all ten wells have now established 30-day initial production rates. The average 30-day initial production rate per well for these 10 wells is 772 bbl/d. Initial well performance continues to outperform type curve assumptions and we now hold nine of the top ten initial rate wells drilled to date across the play.

Our second half drilling program kicked off in July and we expect to drill 14 additional Clearwater wells, including 13 wells at Peavine and one well at Seal that follows up a successful exploration well from 2021. The first two wells from the H2/2022 drilling program are scheduled to be onstream mid-August.

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

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

Production in the Pembina Duvernay averaged 1,756 boe/d (81% oil and NGL) during Q2/2022.

We continue to advance the delineation of the Pembina Duvernay Shale, an early stage, high operating netback light oil resource play. During the second quarter, we completed a three-well pad that was drilled during the first quarter. All three wells are now flowing back and initial results are encouraging and tracking to type well forecast. The wells flow to a Baytex operated oil battery with solution gas being processed at a third party deep cut facility. The three wells, each drilled to a vertical depth of 2,400 metres with a horizontal lateral of 1.85 miles, were drilled and completed on budget at approximately $8.1 million per well. Across our Pembina acreage, we hold 200 sections of 100% working interest lands.

Financial Liquidity

On June 1, 2022, we redeemed the remaining US$200 million principal amount of 5.625% long-term notes due 2024 at par. Following this, our net debt[(1)], which includes our credit facilities, long-term notes and working capital, totaled $1.12 billion at June 30, 2022, down from $1.41 billion at December 31, 2021.

As of June 30, 2022, we had $582 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $599 million.

Risk Management

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

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

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

A complete listing of our financial derivative contracts can be found in Note 16 to our Q2/2022 financial statements.

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

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 30, 2022 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

Conference Call Tomorrow
9:00 a.m. MDT (11:00 a.m. EDT)

Baytex will host a conference call tomorrow, July 28, 2022, starting at 9:00am MDT (11:00am EDT). To participate, please dial toll free in North America 1-800-319-4610 or international 1-416-915-3239. Alternatively, to listen to the conference call online, please enter http://services.choruscall.ca/links/baytex20220728.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 plan to increase direct shareholder returns to 50% of free cash flow and accelerate our share buyback program on reaching net debt of $800 million in late 2022 or early 2023; that our shares are undervalued in relation to current operations; our focus on strong capital discipline and generating free cash flow; that we expect exploration and development expenditures toward the high end of our guidance range and to generate $700 million ($1.25 per basic share) of free cash flow *in 2022; our revised guidance for 2022 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; our expected 1.0x net debt to EBITDA ratio at a US$45 WTI price when we reach our $400 million net debt target; that we will have flexibility to run our business through commodity price cycles and generate meaningful shareholder returns when our net debt target of $400 million is reached; that we expect to reach our $400 million net debt target by the end of 2023 and will consider steps to further enhance shareholder returns once reached; our CEO's intention to retire in January 2023; that Mr. LaFehr will lead the execution of the 2022 plan and 2023 budget preparation, which includes advancing our shareholder return framework; in 2022 that we expect to: bring on production 18 net wells in the Eagle Ford and 130 in the Viking; that we expect to drill 9 net Bluesky wells at Peace River and 31 net wells at Lloydminster in 2022; we plan to drill 14 additional Clearwater wells in H2/2022, with the first two wells on-stream mid-August; that the Clearwater generates among the strongest economics in our portfolio with payouts of less than three months and has the ability to grow organically while enhancing our free cash flow profile; to date we have de-risked 50 sections of Peavine lands which hold the potential for 200 locations; we have over 125 sections that are highly prospective for Clearwater development; we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility; the percentage of our net exposure to crude oil, the WTI-MSW differential and WCS differential that we have hedged for 2022 and the percentage of our net exposure to crude oil that we have hedged for 2023.*

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

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

These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2021, filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission and in our other public filings.

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

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

Specified Financial Measures

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

Non-GAAP Financial Measures

Total sales, net of blending and other expense

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

Operating netback

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

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

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2022**	2021	**2022**	2021
Petroleum and natural gas sales	**$ 854,169**	$ 442,354	**$ 1,527,994**	$ 827,056
Blending and other expense	**(56,895)**	(19,967)	**(98,335)**	(37,087)
Total sales, net of blending and other expense	**797,274**	422,387	**1,429,659**	789,969
Royalties	**(171,559)**	(81,531)	**(294,279)**	(148,481)
Operating expense	**(107,426)**	(82,901)	**(208,192)**	(163,449)
Transportation expense	**(11,758)**	(7,486)	**(20,973)**	(16,274)
Operating netback	**$ 506,531**	$ 250,469	**$ 906,215**	$ 461,765

Free cash flow

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

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

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2022**	2021	**2022**	2021
Cash flows from operating activities	**$ 360,034**	$ 171,876	**$ 559,008**	$ 292,856
Change in non-cash working capital	**(17,046)**	3,014	**60,294**	37,199
Additions to exploration and evaluation assets	**(2,338)**	(428)	**(5,897)**	(644)
Additions to oil and gas properties	**(94,295)**	(61,057)	**(244,558)**	(144,429)
Payments on lease obligations	**(1,039)**	(919)	**(2,213)**	(2,001)
Free cash flow	**$ 245,316**	$ 112,486	**$ 366,634**	$ 182,981

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)		**June 30, 2022**		December 31, 2021
Credit facilities	**$**	**494,410**	$	505,171
Unamortized debt issuance costs - Credit facilities (1)		**2,507**		1,343
Long-term notes		**634,758**		874,527
Unamortized debt issuance costs - Long-term notes (1)		**8,842**		11,393
Trade and other payables		**309,163**		190,692
Trade and other receivables		**(326,383)**		(173,409)
Net debt	**$**	**1,123,297**	$	1,409,717

(1) Unamortized debt issuance costs were obtained from Note 6 - Credit Facilities and Note 7 - Long-term Notes from the consolidated financial statements for the three and six months ended June 30, 2022.

Adjusted funds flow

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

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

	Three Months Ended June 30				Six Months Ended June 30			
($ thousands)		**2022**		2021		**2022**		2021
Cash flow from operating activities	**$**	**360,034**	$	171,876	**$**	**559,008**	$	292,856
Change in non-cash working capital		**(17,046)**		3,014		**60,294**		37,199
Asset retirement obligations settled		**2,716**		993		**6,009**		2,410
Adjusted funds flow	**$**	**345,704**	$	175,883	**$**	**625,311**	$	332,465

Advisory Regarding Oil and Gas Information

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

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

Throughout this news release, "oil and NGL" refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and six months ended June 30, 2022. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas. All production from our Peavine asset is 100% Heavy Oil.

	Three Months Ended June 30, 2022					Six Months Ended June 30, 2022				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	10,216	10	31	12,471	12,336	10,898	8	30	11,801	12,902
Lloydminster	11,051	8	—	1,729	11,347	10,775	11	—	1,758	11,079
Peavine	7,319	—	—	—	7,319	5,248	—	—	—	5,248
Canada - Light										
Viking	—	14,103	184	13,202	16,487	—	14,894	186	12,552	17,172
Duvernay	—	801	620	2,007	1,756	—	896	705	2,174	1,963
Remaining Properties	—	753	983	23,627	5,674	—	810	956	24,158	5,792
United States										
Eagle Ford	—	17,332	5,650	31,133	28,170	—	16,914	5,675	31,430	27,828
Total	28,586	33,007	7,468	84,169	83,090	26,921	33,533	7,552	83,873	81,985

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 200 or more potential drilling locations identified in the Clearwater, as at December 31, 2021, 4 are proved locations, 5 are probable locations and the remainder are unbooked locations.

Baytex Energy Corp.

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

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

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BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three and six months ended June 30, 2022 and 2021
Dated July 27, 2022

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and six months ended June 30, 2022. This information is provided as of July 27, 2022. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three and six months ended June 30, 2022 ("Q2/2022" and "YTD 2022") have been compared with the results for the three and six months ended June 30, 2021 ("Q2/2021" and "YTD 2021"). This MD&A should be read in conjunction with the Company's condensed consolidated interim financial statements ("consolidated financial statements") for the three and six months ended June 30, 2022, its audited comparative consolidated financial statements for the years ended December 31, 2021 and 2020, together with the accompanying notes, and its Annual Information Form ("AIF") for the year ended December 31, 2021. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

In this MD&A, 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, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements along with certain measures which do not have any standardized meaning in accordance with International Financial Reporting Standards ("IFRS") as prescribed by the International Accounting Standards Board. The terms "operating netback", "free cash flow", "average royalty rate", "heavy oil, net of blending and other expense" and "total sales, net of blending and other expense" are specified financial measures that do not have any standardized meaning as prescribed by IFRS and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. This MD&A also contains the terms "adjusted funds flow", "net debt" and "net debt to adjusted funds flow ratio" which are capital management measures. Refer to our advisory on forward-looking information and statements and a summary of our specified financial measures at the end of the MD&A.

BAYTEX ENERGY CORP.

Baytex Energy Corp. is a North American focused energy company based in Calgary, Alberta. The company operates in Canada and the United States ("U.S."). The Canadian operating segment includes our light oil assets in the Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford assets in Texas.

SECOND QUARTER HIGHLIGHTS

Baytex delivered strong operating and financial results in Q2/2022. Energy prices strengthened to multi-year highs due to elevated uncertainty of global oil and natural gas supply after Russia's invasion of Ukraine in addition to limited production growth resulting from oil and gas producers' capital discipline. As a result, the average WTI benchmark price for Q2/2022 was US$108.41/bbl which was US$42.34/bbl higher than Q2/2021 when WTI averaged US$66.07/bbl. The strong benchmark prices contributed to adjusted funds flow(1) of $345.7 million, free cash flow(2) of $245.3 million and a $152.4 million reduction in net debt(1). We initiated our share buyback program after reaching our initial debt target of $1.2 billion early in Q2/2022 and repurchased 9.1 million common shares for $62.5 million during the quarter. Production increased to 83,090 boe/d in Q2/2022 compared to 81,162 boe/d in Q2/2021 primarily from strong well results in our Clearwater program. Production was consistent with our expectations and within our annual guidance range of 83,000 - 85,000 boe/d.

Exploration and development expenditures of $96.6 million during Q2/2022 reflects lower seasonal activity levels with $51.9 million invested in Canada and $44.8 million in the U.S.. In Canada, we brought 13 (12.8 net) heavy oil wells and 9 (8.2 net) light oil wells on production during Q2/2022 which resulted in production of 54,919 boe/d that increased 7,714 boe/d from Q2/2021. In the U.S., activity has been slower than in 2021 and we brought 20 (3.8 net) wells on production during Q2/2022 which resulted in production of 28,170 boe/d that was 5,787 boe/d lower than Q2/2021.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A 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 MD&A for further information.

Adjusted funds flow[(1)] of $345.7 million in Q2/2022 was $169.8 million higher than Q2/2021 as a result of higher benchmark prices and slightly higher production. Our strong operating and financial results contributed to net income of $181.0 million for Q2/2022 compared to net income of $1.1 billion in Q2/2021 which was a result of impairment reversals.

We used our free cash flow[(2)] of $245.3 million generated during Q2/2022 to reduce our debt and initiate shareholder returns. During Q2/2022 we repurchased 9.1 million common shares and we used our revolving credit facility to complete the repurchase and cancellation of the remaining US$200 million principal of the 5.625% Notes due in 2024. On April 1, 2022, we increased availability under our revolving credit facilities to US$850 million and extended maturity to April 1, 2026.

Net debt[(1)] of $1.12 billion at June 30, 2022 was $286.4 million lower than $1.41 billion at December 31, 2021 which reflects $366.6 million of free cash flow generated in YTD 2022 offset by $62.5 million of share repurchases and a $14.9 million increase in the reported amount of our U.S. dollar denominated net debt due to the weakening of the Canadian dollar relative to the U.S. dollar during YTD 2022.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A 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 MD&A for further information.

2022 GUIDANCE

We have fine-tuned several of our cost assumptions to reflect increased royalties due to higher commodity prices and further inflationary pressures on operating and transportation expenses, related to labor, fuel, electricity and hauling. We are now forecasting approximately 15% inflation on a combined basis for operating and transportation expenses as compared to 2021.

The following table highlights our 2022 annual guidance.

	Previous Annual Guidance [(1)]	Revised Annual Guidance
Exploration and development expenditures	$450 - $500 million	no change
Production (boe/d)	83,000 - 85,000	no change
Expenses:		
Average royalty rate [(3)]	20.0% - 20.5%	21.0% - 22.0%
Operating [(4)]	$13.00 - $13.50/boe	$13.75 - $14.25/boe
Transportation [(4)]	$1.30 - $1.40/boe	$1.50 - $1.60/boe
General and administrative [(4)]	$43 million ($1.40/boe)	no change
Interest [(4)]	$75 million ($2.45/boe)	no change
Leasing expenditures	no change	no change
Asset retirement obligations	no change	no change

(1) As announced on April 28, 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 MD&A for further information.
(3) Refer to Operating Expense, Transportation Expense, General and Administrative Expense and Financing and Interest Expense sections of this MD&A for description of the composition of these measures.

RESULTS OF OPERATIONS

The Canadian operating segment includes our light oil assets in Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford assets in Texas.

Production

	Three Months Ended June 30					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**15,675**	**17,332**	**33,007**	15,661	21,473	37,134
Heavy oil	**28,586**	**—**	**28,586**	21,269	—	21,269
Natural Gas Liquids (NGL)	**1,818**	**5,650**	**7,468**	1,779	5,784	7,563
Total liquids (bbl/d)	**46,079**	**22,982**	**69,061**	38,709	27,257	65,966
Natural gas (mcf/d)	**53,036**	**31,133**	**84,169**	50,974	40,198	91,172
Total production (boe/d)	**54,919**	**28,170**	**83,090**	47,205	33,957	81,162
Production Mix						
Segment as a percent of total	**66 %**	**34 %**	**100 %**	58 %	42 %	100 %
Light oil and condensate	**29 %**	**62 %**	**40 %**	33 %	63 %	46 %
Heavy oil	**52 %**	**— %**	**34 %**	45 %	— %	26 %
NGL	**3 %**	**20 %**	**9 %**	4 %	17 %	9 %
Natural gas	**16 %**	**18 %**	**17 %**	18 %	20 %	19 %

	Six Months Ended June 30					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**16,619**	**16,914**	**33,533**	17,434	18,852	36,286
Heavy oil	**26,921**	**—**	**26,921**	21,627	—	21,627
Natural Gas Liquids (NGL)	**1,877**	**5,675**	**7,552**	1,874	5,030	6,904
Total liquids (bbl/d)	**45,417**	**22,589**	**68,006**	40,935	23,882	64,817
Natural gas (mcf/d)	**52,443**	**31,430**	**83,873**	52,036	38,921	90,957
Total production (boe/d)	**54,156**	**27,828**	**81,985**	49,609	30,369	79,978
Production Mix						
Segment as a percent of total	**66 %**	**34 %**	**100 %**	62 %	38 %	100 %
Light oil and condensate	**31 %**	**61 %**	**41 %**	35 %	62 %	45 %
Heavy oil	**50 %**	**— %**	**33 %**	44 %	— %	27 %
NGL	**3 %**	**20 %**	**9 %**	4 %	17 %	9 %
Natural gas	**16 %**	**19 %**	**17 %**	17 %	21 %	19 %

Production was 83,090 boe/d for Q2/2022 and 81,985 boe/d for YTD 2022 compared to 81,162 boe/d for Q2/2021 and 79,978 boe/d for YTD 2021. Total production was higher in Q2/2022 and YTD 2022 compared to comparable periods of 2021 due to our successful development program in Canada which includes strong well results from our Clearwater development program.

In Canada, production was 54,919 boe/d for Q2/2022 and 54,156 boe/d for YTD 2022 compared to 47,205 boe/d for Q2/2021 and 49,609 boe/d for YTD 2021. Our successful 2021 and early 2022 development program and strong well performance from our Clearwater development program has resulted in production that was 7,714 boe/d higher in Q2/2022 and 4,547 boe/d higher YTD 2022 relative to the comparative periods of of 2021.

In the U.S., production was 28,170 boe/d for Q2/2022 and 27,828 boe/d for YTD 2022 compared to 33,957 boe/d for Q2/2021 and 30,369 boe/d for YTD 2021. U.S. production was lower in 2022 due to reduced activity levels during the second half of 2021 and during YTD 2022. We initiated production from 37 (8.6 net) wells during YTD 2022 compared to 62 (17.2 net) wells during the comparative period in 2021.

Total production of 81,985 boe/d for YTD 2022 is consistent with expectations and is slightly below our annual guidance range of 83,000 - 85,000 boe/d for 2022 as we expect production to increase over the remainder of 2022 as we execute our capital development program.

COMMODITY PRICES

The prices received for our crude oil and natural gas production directly impact our earnings, free cash flow and our financial position.

Crude Oil

Global benchmark pricing for crude oil continued to strengthen during Q2/2022 as a result of the war in Ukraine which has resulted in elevated uncertainty for the global supply of crude oil. These factors combined with limited production growth from producers' capital discipline resulted in the WTI benchmark price averaging US$108.41/bbl for Q2/2022 and US$101.35/bbl for YTD 2022 compared to Q2/2021 and YTD 2021 when WTI averaged US$66.07/bbl and US$61.96/bbl, respectively.

We compare the price received for our U.S. crude oil production to the Magellan East Houston ("MEH") stream at Houston, Texas which is a representative benchmark for light oil pricing at the U.S. Gulf coast. The MEH benchmark averaged US$112.41/bbl during Q2/2022 and US$104.56/bbl during YTD 2022 which is higher than US$67.15/bbl during Q2/2021 and US$63.26/bbl during YTD 2021. The MEH benchmark trades at a premium to WTI as a result of access to global markets. The MEH benchmark premium to WTI was US$4.00/bbl and US$3.21/bbl for Q2/2022 and YTD 2022 compared to premiums of US$1.08/bbl and US$1.30/bbl for Q2/2021 and YTD 2021, respectively. The MEH benchmark traded at a higher premium to WTI in both periods of 2022 as a result of heightened uncertainty over global supply relative to 2021.

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets from Western Canada. Differentials for Canadian oil prices relative to WTI fluctuate from period to period based on production and inventory levels in Western Canada.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $137.79/bbl during Q2/2022 and $126.72/bbl during YTD 2022 compared to $77.28/bbl during Q2/2021 and $71.93/bbl during YTD 2021. Edmonton par traded at a discount to WTI of US$0.47/bbl for Q2/2022 and US$1.68/bbl for YTD 2022 which is narrower compared to a discount of US$3.13/bbl for Q2/2021 and US$4.28/bbl for YTD 2021 due to higher demand for Canadian light oil in 2022.

We compare the price received for our heavy oil production in Canada to the WCS heavy oil benchmark. The WCS heavy oil price for Q2/2022 and YTD 2022 averaged $122.05/bbl and $111.48/bbl respectively compared to $67.03/bbl and $62.33/bbl for the same periods of 2021. The WCS heavy oil differential was US$12.80/bbl in Q2/2022 and US$13.67/bbl in YTD 2022 which is wider than US$11.48/bbl for Q2/2021 and US$11.98/bbl for YTD 2021 due to reduced refining capacity for Canadian heavy oil following the release of oil from the U.S. Strategic Petroleum Reserve.

Natural Gas

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. Strong global demand combined with reduced natural gas inventory levels contributed to higher NYMEX benchmark prices in 2022 relative to 2021.The NYMEX natural gas benchmark averaged US$7.17/mmbtu for Q2/2022 and US$6.06/mmbtu for YTD 2022 which is higher than US$2.83/mmbtu for Q2/2021 and US$2.76/mmbtu for YTD 2021.

In Canada, we receive natural gas pricing based on the AECO benchmark which continues to trade at a discount to NYMEX as a result of limited market access for Canadian natural gas production. Lower production and an increased demand for natural gas resulted in reduced inventory levels in Canada and contributed to stronger AECO benchmark pricing in 2022 relative to 2021. The AECO benchmark averaged $6.27/mcf during Q2/2022 and $5.43/mcf during YTD 2022 which is higher than $2.85/mcf for Q2/2021 and $2.89/mcf for YTD 2021.

The following tables compare select benchmark prices and our average realized selling prices for the three and six months ended June 30, 2022 and 2021.

	Three Months Ended June 30			Six Months Ended June 30		
	2022	2021	Change	**2022**	2021	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	**108.41**	66.07	42.34	**101.35**	61.96	39.39
MEH oil (US$/bbl)[2]	**112.41**	67.15	45.26	**104.56**	63.26	41.30
MEH oil differential to WTI (US$/bbl)	**4.00**	1.08	2.92	**3.21**	1.30	1.91
Edmonton par oil ($/bbl)[3]	**137.79**	77.28	60.51	**126.72**	71.93	54.79
Edmonton par oil differential to WTI (US$/bbl)	**(0.47)**	(3.13)	2.66	**(1.68)**	(4.28)	2.60
WCS heavy oil ($/bbl)[4]	**122.05**	67.03	55.02	**111.48**	62.33	49.15
WCS heavy oil differential to WTI (US$/bbl)	**(12.80)**	(11.48)	(1.32)	**(13.67)**	(11.98)	(1.69)
AECO natural gas ($/mcf)[5]	**6.27**	2.85	3.42	**5.43**	2.89	2.54
NYMEX natural gas (US$/mmbtu)[6]	**7.17**	2.83	4.34	**6.06**	2.76	3.30
CAD/USD average exchange rate	**1.2766**	1.2279	0.0487	**1.2714**	1.2471	0.0243

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) MEH refers to arithmetic average of the Argus WTI Houston differential weighted index price for the applicable period.
(3) Edmonton par refers to the average posting price for the benchmark MSW crude oil.
(4) WCS refers to the average posting price for the benchmark WCS heavy oil.
(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(6) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Three Months Ended June 30					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)[1]	**$ 135.29**	**$ 141.14**	**$ 138.36**	$ 74.57	$ 81.06	$ 78.32
Heavy oil, net of blending and other expense ($/bbl)[2]	**111.18**	**—**	**111.18**	56.74	—	56.74
NGL ($/bbl)[1]	**50.09**	**48.42**	**48.83**	23.38	31.91	29.90
Natural gas ($/mcf)[1]	**7.01**	**8.99**	**7.74**	3.05	3.59	3.29
Total sales, net of blending and other expense ($/boe)[2]	**$ 104.91**	**$ 106.48**	**$ 105.44**	$ 54.49	$ 60.95	$ 57.19

	Six Months Ended June 30					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)[1]	**$ 124.05**	**$ 131.77**	**$ 127.95**	$ 69.02	$ 77.36	$ 73.36
Heavy oil, net of blending and other expense ($/bbl)[2]	**101.01**	**—**	**101.01**	51.53	—	51.53
NGL ($/bbl)[1]	**46.43**	**45.66**	**45.85**	24.02	32.88	30.48
Natural gas ($/mcf)[1]	**5.84**	**7.52**	**6.47**	3.04	5.63	4.15
Total sales, net of blending and other expense ($/boe)[2]	**$ 95.55**	**$ 97.90**	**$ 96.34**	$ 50.82	$ 60.69	$ 54.57

(1) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.
(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 MD&A for further information.

Average Realized Sales Prices

Our total sales, net of blending and other expense per boe(1) was $105.44/boe for Q2/2022 and $96.34/bbl for YTD 2022 compared to $57.19/boe for Q2/2021 and $54.57/boe for YTD 2021. In Canada, our realized price of $104.91/boe for Q2/2022 was $50.42/boe higher than $54.49/boe for Q2/2021. Our realized price in the U.S. was $106.48/boe in Q2/2022 which is $45.53/boe higher than $60.95/boe in Q2/2021. The increase in our realized price in Canada and the U.S. for Q2/2022 and YTD 2022 was a result of higher North American benchmark prices relative to the same periods of 2021.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price(2) was $135.29/bbl for Q2/2022 and $124.05/bbl for YTD 2022 compared to $74.57/bbl for Q2/2021 and $69.02/bbl for YTD 2021. Our realized light oil and condensate price for Q2/2022 and YTD 2022 increased with the improvement in the benchmark price and represents discounts to the Edmonton par price of $2.50/bbl and $2.67/bbl for Q2/2022 and YTD 2022, respectively, which is consistent with a discount of $2.71/bbl in Q2/2021 and $2.91/bbl in YTD 2021.

We compare the price received for our U.S. light oil and condensate production to the MEH benchmark. Our realized light oil and condensate price averaged $141.14/bbl for Q2/2022 and $131.77/bbl for YTD 2022 compared to $81.06/bbl for Q2/2021 and $77.36/bbl for YTD 2021. Expressed in U.S. dollars, our realized light oil and condensate price of US$110.56/bbl for Q2/2022 and US$103.64/bbl for YTD 2022 represents discounts to MEH of US$1.85/bbl and US$0.92/bbl Q2/2022 and YTD 2022, respectively, which is consistent with discounts of US$1.13/bbl for Q2/2021 and US$1.23/bbl for YTD 2021.

Our realized heavy oil price, net of blending and other expense(1) averaged $111.18/bbl in Q2/2022 and $101.01/bbl in YTD 2022 compared to $56.74/bbl in Q2/2021 and $51.53/bbl in YTD 2021. Our realized heavy oil, net of blending and other expense for Q2/2022 and YTD 2022 was $54.44/bbl and $49.48/bbl higher relative to Q2/2021 and YTD 2021, respectively, which is consistent with a $55.02/bbl and $49.15/bbl increase in the WCS benchmark price over the same periods.

Our realized NGL price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes and changes in the market prices for the underlying products. Our realized NGL price(2) was $48.83/bbl in Q2/2022 or 35% of WTI (expressed in Canadian dollars) and $45.85/bbl in YTD 2022 or 36% of WTI (expressed in Canadian dollars) compared to $29.90/bbl or 37% of WTI (expressed in Canadian dollars) in Q2/2021 and $30.48/bbl or 39% of WTI (expressed in Canadian dollars) in YTD 2021. The increase in our realized NGL price is primarily a result of higher WTI pricing as our realization as a percentage of WTI is fairly consistent in 2022 relative to the comparative periods of 2021.

We compare our realized natural gas price in Canada to the AECO benchmark price and to the NYMEX benchmark in the U.S.. Our realized natural gas price(2) was $7.01/mcf for Q2/2022 and $5.84/mcf for YTD 2022 compared to $3.05/mcf in Q2/2021 and $3.04/mcf for YTD 2021. In the U.S., our realized natural gas price was US$7.04/mcf for Q2/2022 and US$5.91/mcf for YTD 2022 compared to US$2.92/mcf for Q2/2021 and US$4.51/mcf for YTD 2021. The increase in our realized gas price in Canada and the U.S. is relatively consistent with the increases in the AECO and NYMEX benchmarks in 2022 compared to the same periods of 2021.

(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 MD&A for further information.

(2) Calculated as light oil and condensate, NGL or natural gas sales divided by barrels of oil equivalent production volume for the applicable period.

PETROLEUM AND NATURAL GAS SALES

	Three Months Ended June 30					
	2022			2021		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 192,986**	**$ 222,606**	**$ 415,592**	$ 106,269	$ 158,390	$ 264,659
Heavy oil	**346,101**	**—**	**346,101**	129,782	—	129,782
NGL	**8,288**	**24,895**	**33,183**	3,786	16,796	20,582
Total oil sales	**547,375**	**247,501**	**794,876**	239,837	175,186	415,023
Natural gas sales	**33,822**	**25,471**	**59,293**	14,189	13,142	27,331
Total petroleum and natural gas sales	**581,197**	**272,972**	**854,169**	254,026	188,328	442,354
Blending and other expense	**(56,895)**	**—**	**(56,895)**	(19,967)	—	(19,967)
Total sales, net of blending and other expense(1)	**$ 524,302**	**$ 272,972**	**$ 797,274**	$ 234,059	$ 188,328	$ 422,387

	Six Months Ended June 30					
	2022			2021		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 373,141**	**$ 403,426**	**$ 776,567**	$ 217,814	$ 263,986	$ 481,800
Heavy oil	**590,539**	**—**	**590,539**	238,820	—	238,820
NGL	**15,772**	**46,902**	**62,674**	8,150	29,939	38,089
Total oil sales	**979,452**	**450,328**	**1,429,780**	464,784	293,925	758,709
Natural gas sales	**55,449**	**42,765**	**98,214**	28,664	39,683	68,347
Total petroleum and natural gas sales	**1,034,901**	**493,093**	**1,527,994**	493,448	333,608	827,056
Blending and other expense	**(98,335)**	**—**	**(98,335)**	(37,087)	—	(37,087)
Total sales, net of blending and other expense(1)	**$ 936,566**	**$ 493,093**	**$ 1,429,659**	$ 456,361	$ 333,608	$ 789,969

(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 MD&A for further information.

Total sales, net of blending and other expense, of $797.3 million for Q2/2022 increased $374.9 million from $422.4 million reported for Q2/2021 while total sales, net of blending and other expense, of $1,429.7 million for YTD 2022 increased $639.7 million from $790.0 million reported for YTD 2021. The increase in total sales is primarily a result of higher realized pricing consistent with the increase in benchmark pricing along with a modest increase in production due to our successful development program in Canada.

In Canada, total sales, net of blending and other expense, was $524.3 million for Q2/2022 which is an increase of $290.2 million from $234.1 million reported for Q2/2021. The increase in total petroleum and natural gas sales was primarily due to higher realized pricing for Q2/2022 relative to Q2/2021. Our increased realized price resulted in a $252.0 million increase in total sales, net of blending and other expense, while a modest increase in production contributed to a $38.3 million increase in total sales, net of blending and other expense, relative to Q2/2021. Improvements in benchmark prices resulted in our total sales, net of blending and other expense, increasing to $936.6 million in YTD 2022 from $456.4 million in YTD 2021.

In the U.S., petroleum and natural gas sales were $273.0 million for Q2/2022 which is an increase of $84.6 million from $188.3 million reported for Q2/2021. Total petroleum and natural gas sales increased $116.7 million due to higher realized pricing for Q2/2022 relative to Q2/2021 while lower production resulted in a $32.1 million decrease in total sales relative to Q2/2021. Higher realized pricing in YTD 2022 resulted in petroleum and natural gas sales of $493.1 million which was $159.5 million higher than $333.6 million in YTD 2021 despite lower production in YTD 2022 relative to YTD 2021.

ROYALTIES

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects and are generally expressed as a percentage of 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. The following table summarizes our royalties and royalty rates for the three and six months ended June 30, 2022 and 2021.

	Three Months Ended June 30					
	2022			2021		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 91,133**	**$ 80,426**	**$ 171,559**	$ 26,193	$ 55,338	$ 81,531
Average royalty rate(1)(2)	**17.4 %**	**29.5 %**	**21.5 %**	11.2 %	29.4 %	19.3 %
Royalties per boe(3)	**$ 18.24**	**$ 31.37**	**$ 22.69**	$ 6.10	$ 17.91	$ 11.04

	Six Months Ended June 30					
	2022			2021		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 148,809**	**$ 145,470**	**$ 294,279**	$ 50,857	$ 97,624	$ 148,481
Average royalty rate(1)(2)	**15.9 %**	**29.5 %**	**20.6 %**	11.1 %	29.3 %	18.8 %
Royalties per boe(3)	**$ 15.18**	**$ 28.88**	**$ 19.83**	$ 5.66	$ 17.76	$ 10.26

(1) Average royalty rate is calculated as royalties divided by total sales, net of blending and other expense.
(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 MD&A for further information.
(3) Royalties per boe is calculated as royalties divided by barrels of oil equivalent production volume for the applicable period.

Royalties for Q2/2022 were $171.6 million or 21.5% of total sales, net of blending and other expense, compared to $81.5 million or 19.3% for Q2/2021. Total royalties for YTD 2022 were $294.3 million or 20.6% of total sales, net of blending and other expense, compared to $148.5 million or 18.8% for YTD 2021. Total royalty expense was higher for Q2/2022 and YTD 2022 due to higher total sales, net of blending and other expense, along with a slight increase in our royalty rate relative to the same periods of 2021. Our royalty rates of 21.5% for Q2/2022 and 20.6% for YTD 2022 were higher than 19.3% for Q2/2021 and 18.8% for YTD 2021 due to a higher royalty rate on our Canadian properties as a result of higher commodity prices. Our average royalty rate of 20.6% for YTD 2022 is fairly consistent with our annual guidance range of 21.0% - 22.0% for 2022.

Our Canadian royalty rates of 17.4% for Q2/2022 and 15.9% for YTD 2022 were higher than 11.2% for Q2/2021 and 11.1% for YTD 2021 due to higher benchmark commodity prices which resulted in a higher royalty rate on our Canadian properties in 2022 relative to 2021. In the U.S., royalties averaged 29.5% of total sales for Q2/2022 and YTD 2022, which is consistent with 29.4% for Q2/2021 and 29.3% for YTD 2021 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

OPERATING EXPENSE

	Three Months Ended June 30					
	2022			2021		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 82,471**	**$ 24,955**	**$ 107,426**	$ 61,793	$ 21,108	$ 82,901
Operating expense per boe(1)	**$ 16.50**	**$ 9.73**	**$ 14.21**	$ 14.39	$ 6.83	$ 11.22

	Six Months Ended June 30					
	2022			2021		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 161,011**	**$ 47,181**	**$ 208,192**	$ 123,154	$ 40,295	$ 163,449
Operating expense per boe(1)	**$ 16.43**	**$ 9.37**	**$ 14.03**	$ 13.72	$ 7.33	$ 11.29

(1) Operating expense per boe is calculated as operating expense divided by barrels of oil equivalent production volume for the applicable period.

Total operating expense was $107.4 million ($14.21/boe) for Q2/2022 and $208.2 million ($14.03/boe) for YTD 2022 compared to $82.9 million ($11.22/boe) for Q2/2021 and $163.4 million ($11.29/boe) for YTD 2021. Total operating expense for both periods in 2022 increased with production and also reflects cost inflation experienced in our industry relative to 2021. Operating expense of $14.03 for YTD 2022 is consistent with our annual guidance range of $13.75 - $14.25/boe for 2022.

In Canada, operating expense was $82.5 million ($16.50/boe) for Q2/2022 and $161.0 million ($16.43/boe) for YTD 2022 compared to $61.8 million ($14.39/boe) for Q2/2021 and $123.2 million ($13.72/boe) for YTD 2021. U.S. operating expense was $25.0 million ($9.73/boe) for Q2/2022 and $47.2 million ($9.37/boe) for YTD 2022 compared to $21.1 million ($6.83/boe) for Q2/2021 and $40.3 million ($7.33/boe) in YTD 2021. Expressed in U.S. dollars, per unit operating expense was US$7.62/boe in Q2/2022 and US$7.37/boe in YTD 2022 which was higher than US$5.56/boe for Q2/2021 and US$5.88/boe in YTD 2021.

The increase in per unit operating expense in Canada and the U.S. was primarily due to increased costs from energy inputs resulting in higher fuel, electricity and hauling costs along with additional workover activity in 2022 relative to 2021.

TRANSPORTATION EXPENSE

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of oil in Canada to pipeline and rail terminals which can vary from period to period depending on hauling distances as we seek to optimize sales prices and trucking rates.

The following table compares our transportation expense for the three and six months ended June 30, 2022 and 2021.

	Three Months Ended June 30					
	2022			2021		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 11,758**	**$ —**	**$ 11,758**	$ 7,486	$ —	$ 7,486
Transportation expense per boe(1)	**$ 2.35**	**$ —**	**$ 1.56**	$ 1.74	$ —	$ 1.01

	Six Months Ended June 30					
	2022			2021		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 20,973**	**$ —**	**$ 20,973**	$ 16,274	$ —	$ 16,274
Transportation expense per boe	**$ 2.14**	**$ —**	**$ 1.41**	$ 1.81	$ —	$ 1.12

(1) Transportation expense per boe is calculated as transportation expense divided by barrels of oil equivalent production volume for the applicable period.

Transportation expense was $11.8 million ($1.56/boe) for Q2/2022 and $21.0 million ($1.41/boe) for YTD 2022 compared to $7.5 million ($1.01/boe) for Q2/2021 and $16.3 million ($1.12/boe) for YTD 2021. Per unit transportation expense of $1.41/boe for YTD 2022 is slightly below our annual guidance of $1.50 - $1.60/boe for 2022.

BLENDING AND OTHER EXPENSE

Blending and other expense primarily includes the cost of blending diluent purchased to reduce the viscosity of our heavy oil transported through pipelines in order to meet pipeline specifications. The purchased diluent is recorded as blending and other expense. The price received for the blended product is recorded as heavy oil sales revenue. We net blending and other expense against heavy oil sales to compare the realized price on our produced volumes to benchmark pricing.

Blending and other expense was $56.9 million for Q2/2022 and $98.3 million for YTD 2022 compared to $20.0 million for Q2/2021 and $37.1 million for YTD 2021. Higher blending and other expense reflects an increase in the price of condensate purchased as diluent along with an increase in heavy oil production shipped via pipeline in 2022 relative to 2021.

FINANCIAL DERIVATIVES

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates, interest rates and changes in our share price. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our adjusted funds flow. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets for commodities and currencies fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the three and six months ended June 30, 2022 and 2021.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2022**	2021	Change	**2022**	2021	Change
Realized financial derivatives loss						
Crude oil	**$ (112,071)**	$ (38,234)	$ (73,837)	**$ (191,597)**	$ (58,275)	$ (133,322)
Natural gas	**(11,971)**	(790)	(11,181)	**(16,811)**	(1,517)	(15,294)
Total	**$ (124,042)**	$ (39,024)	$ (85,018)	**$ (208,408)**	$ (59,792)	$ (148,616)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ 47,816**	$ (81,069)	$ 128,885	**$ (91,502)**	$ (166,539)	$ 75,037
Natural gas	**9,363**	(7,898)	17,261	**(7,271)**	(9,285)	2,014
Equity total return swap ("Equity TRS")	**1,589**	4,484	(2,895)	**1,280**	5,357	(4,077)
Total	**$ 58,768**	$ (84,483)	$ 143,251	**$ (97,493)**	$ (170,467)	$ 72,974
Total financial derivatives (loss) gain						
Crude oil	**$ (64,255)**	$ (119,303)	$ 55,048	**$ (283,099)**	$ (224,814)	$ (58,285)
Natural gas	**(2,608)**	(8,688)	6,080	**(24,082)**	(10,802)	(13,280)
Equity TRS	**1,589**	4,484	(2,895)	**1,280**	5,357	(4,077)
Total	**$ (65,274)**	$ (123,507)	$ 58,233	**$ (305,901)**	$ (230,259)	$ (75,642)

We recorded total financial derivative loss of $65.3 million for Q2/2022 and $305.9 million for YTD 2022 compared to a loss of $123.5 million for Q2/2021 and of $230.3 million for YTD 2021. The realized financial derivatives loss of $124.0 million for Q2/2022 and $208.4 million for YTD 2022 were primarily a result of the market prices for crude oil and natural gas settling at levels above those set in our derivative contracts. The unrealized gain of $58.8 million for Q2/2022 and loss of $97.5 million for YTD 2022 reflect changes in forecasted crude oil pricing used to revalue our crude oil contracts in place at June 30, 2022 relative to March 31, 2022 and December 31, 2021 along with losses realized and the valuation of new contracts entered during the period. The fair value of our financial derivative contracts resulted in a net liability of $222.9 million at June 30, 2022 compared to a net liability of $281.6 million at March 31, 2022 and a net liability of $125.4 million at December 31, 2021.

We had the following commodity financial derivative contracts as at July 27, 2022.

	Period	Volume	Price/Unit [1]	Index
Oil				
Basis Swap	Jul 2022 to Dec 2022	12,000 bbl/d	WTI less US$12.40/bbl	WCS
Basis Swap	Jul 2022 to Dec 2022	6,750 bbl/d	WTI less US$3.73/bbl	MSW
Fixed Sell	Jul 2022 to Dec 2022	10,000 bbl/d	US$53.50/bbl	WTI
3-way option[2]	Jul 2022 to Dec 2022	1,500 bbl/d	US$40.00/US$50.00/US$58.10	WTI
3-way option[2]	Jul 2022 to Dec 2022	2,000 bbl/d	US$46.00/US$56.00/US$66.72	WTI
3-way option[2]	Jul 2022 to Dec 2022	2,500 bbl/d	US$47.00/US$57.00/US$67.00	WTI
3-way option[2]	Jul 2022 to Dec 2022	2,500 bbl/d	US$50.00/US$60.00/US$70.00	WTI
3-way option[2]	Jul 2022 to Dec 2022	2,000 bbl/d	US$53.00/US$63.50/US$72.90	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,000 bbl/d	US$55.00/US$66.00/US$84.00	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$60.00/US$75.00/US$91.54	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$100.00	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$106.50	WTI
Natural Gas				
Fixed Sell	Jul 2022 to Dec 2022	5,000 GJ/d	$2.53/GJ	AECO 7A
Fixed Sell	Jul 2022 to Dec 2022	14,250 GJ/d	$2.84/GJ	AECO 5A
Fixed Sell	Jul 2022 to Dec 2022	1,000 mmbtu/d	US$2.94/mmbtu	NYMEX
3-way option[2]	Jul 2022 to Dec 2022	2,500 mmbtu/d	US$2.25/US$2.75/US$3.06	NYMEX
3-way option[2]	Jul 2022 to Dec 2022	1,500 mmbtu/d	US$2.60/US$2.91/US$3.56	NYMEX
3-way option[2]	Jul 2022 to Dec 2022	2,500 mmbtu/d	US$2.60/US$3.00/US$3.83	NYMEX
3-way option[2]	Jul 2022 to Dec 2022	2,500 mmbtu/d	US$2.65/US$2.90/US$3.40	NYMEX
3-way option[2]	Jul 2022 to Dec 2022	2,500 mmbtu/d	US$3.00/US$3.75/US$4.40	NYMEX

(1) Based on the weighted average price per unit for the period.

(2) Producer 3-way option consists of a sold put, a bought put and a sold call. To illustrate, in a US$50.00/US$60.00/US$70.00 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$60.00/bbl when WTI is between US$50.00/bbl and US$60.00/bbl; Baytex receives the market price when WTI is between US$60.00/bbl and US$70.00/bbl; and Baytex receives US$70.00/bbl when WTI is above US$70.00/bbl.

OPERATING NETBACK

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the three and six months ended June 30, 2022 and 2021.

	Three Months Ended June 30					
	2022			2021		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**54,919**	**28,170**	**83,090**	47,205	33,957	81,162
Operating netback:						
Total sales, net of blending and other expense (1)	**$ 104.91**	**$ 106.48**	**$ 105.44**	$ 54.49	$ 60.95	$ 57.19
Less:						
Royalties (2)	**(18.24)**	**(31.37)**	**(22.69)**	(6.10)	(17.91)	(11.04)
Operating expense (2)	**(16.50)**	**(9.73)**	**(14.21)**	(14.39)	(6.83)	(11.22)
Transportation expense (2)	**(2.35)**	**—**	**(1.56)**	(1.74)	—	(1.01)
Operating netback (1)	**$ 67.82**	**$ 65.38**	**$ 66.98**	$ 32.26	$ 36.21	$ 33.92
Realized financial derivatives loss (3)	**—**	**—**	**(16.41)**	—	—	(5.28)
Operating netback after financial derivatives (1)	**$ 67.82**	**$ 65.38**	**$ 50.57**	$ 32.26	$ 36.21	$ 28.64

	Six Months Ended June 30					
	2022			2021		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**54,156**	**27,828**	**81,985**	49,609	30,369	79,978
Operating netback:						
Total sales, net of blending and other expense (1)	**$ 95.55**	**$ 97.90**	**$ 96.34**	$ 50.82	$ 60.69	$ 54.57
Less:						
Royalties (2)	**(15.18)**	**(28.88)**	**(19.83)**	(5.66)	(17.76)	(10.26)
Operating expense (2)	**(16.43)**	**(9.37)**	**(14.03)**	(13.72)	(7.33)	(11.29)
Transportation expense (2)	**(2.14)**	**—**	**(1.41)**	(1.81)	—	(1.12)
Operating netback (1)	**$ 61.80**	**$ 59.65**	**$ 61.07**	$ 29.63	$ 35.60	$ 31.90
Realized financial derivatives loss (3)	**—**	**—**	**(14.04)**	—	—	(4.13)
Operating netback after financial derivatives (1)	**$ 61.80**	**$ 59.65**	**$ 47.03**	$ 29.63	$ 35.60	$ 27.77

(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 MD&A for further information.
(2) Refer to Royalties, Operating Expense and Transportation Expense sections in this MD&A for a description of the composition these measures.
(3) Calculated as realized financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

Our operating netback of $66.98/boe for Q2/2022 and $61.07/boe for YTD 2022 was higher than $33.92/boe for Q2/2021 and $31.90/boe for YTD 2021 due to the increase in benchmark pricing in Canada and the U.S. which resulted in higher per unit sales net of royalties. Total operating and transportation expense of $15.77/boe for Q2/2022 and $15.44/boe for YTD 2022 were higher than $12.23/boe for Q2/2021 and $12.41/boe for YTD 2021 due to inflation which resulted in higher fuel, electricity and hauling costs along with increased workover activity in YTD 2022. Including realized losses on financial derivatives our operating netback was $50.57/boe for Q2/2022 and $47.03/boe for YTD 2022 compared to $28.64/boe for Q2/2021 and $27.77/boe for YTD 2021.

GENERAL AND ADMINISTRATIVE EXPENSE

General and administrative ("G&A") expense includes head office and corporate costs such as salaries and employee benefits, public company costs and administrative recoveries earned for operating exploration and development activities on behalf of our working interest partners. G&A expense fluctuates with head office staffing levels and the level of operated exploration and development activity during the period.

The following table summarizes our G&A expense for the three and six months ended June 30, 2022 and 2021.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2022**	2021	Change	**2022**	2021	Change
Gross general and administrative expense	**$ 12,223**	$ 11,158	$ 1,065	**$ 25,729**	$ 20,619	$ 5,110
Overhead recoveries	**(583)**	(548)	(35)	**(2,407)**	(1,276)	(1,131)
General and administrative expense	**$ 11,640**	$ 10,610	$ 1,030	**$ 23,322**	$ 19,343	$ 3,979
General and administrative expense per boe[1]	**$ 1.54**	$ 1.44	$ 0.10	**$ 1.57**	$ 1.34	$ 0.23

(1) General and administrative expense per boe is calculated as general and administrative expense divided by barrels of oil equivalent production volume for the applicable period.

G&A expense was $11.6 million ($1.54/boe) for Q2/2022 and $23.3 million ($1.57/boe) for YTD 2022 compared to $10.6 million ($1.44/boe) for Q2/2021 and $19.3 million ($1.34/boe) for YTD 2021. G&A expense for Q2/2022 and YTD 2022 was higher relative to the same periods of 2021 due to higher staffing costs associated with increased exploration and development expenditures in Canada during 2022.

G&A expense of $1.57/boe is consistent with expectations and is slightly above our annual guidance of $1.40/boe for 2022 as we expect production to increase over the remainder of the year.

FINANCING AND INTEREST EXPENSE

Financing and interest expense includes interest on our credit facilities, long-term notes and lease obligations as well as non-cash financing costs which include the accretion on our debt issue costs and asset retirement obligations. Financing and interest expense varies depending on debt levels outstanding during the period, the applicable borrowing rates, CAD/USD foreign exchange rates, along with the carrying amount of asset retirement obligations and the discount rates used to present value these obligations.

The following table summarizes our financing and interest expense for the three and six months ended June 30, 2022 and 2021.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2022**	2021	Change	**2022**	2021	Change
Interest on credit facilities	**$ 4,070**	$ 3,250	$ 820	**$ 7,109**	$ 6,586	$ 523
Interest on long-term notes	**16,356**	20,246	(3,890)	**33,700**	41,253	(7,553)
Interest on lease obligations	**48**	58	(10)	**$ 92**	$ 118	(26)
Cash interest	**$ 20,474**	$ 23,554	$ (3,080)	**$ 40,901**	$ 47,957	$ (7,056)
Accretion of debt issue costs	**2,734**	790	1,944	**3,429**	1,539	1,890
Accretion of asset retirement obligations	**3,869**	3,367	502	**6,991**	5,665	1,326
Gain on redemption of long-term notes	**—**	(357)	357	**—**	(357)	357
Financing and interest expense	**$ 27,077**	$ 27,354	$ (277)	**$ 51,321**	$ 54,804	$ (3,483)
Cash interest per boe[1]	**$ 2.71**	$ 3.19	$ (0.48)	**$ 2.76**	$ 3.31	$ (0.55)
Financing and interest expense per boe[1]	**$ 3.58**	$ 3.70	$ (0.12)	**$ 3.46**	$ 3.79	$ (0.33)

(1) Calculated as cash interest or financing and interest expense divided by barrels of oil equivalent production volume for the applicable period.

Financing and interest expense was $27.1 million ($3.58/boe) for Q2/2022 and $51.3 million ($3.46/boe) for YTD 2022 compared to $27.4 million ($3.70/boe) for Q2/2021 and $54.8 million ($3.79/boe) for YTD 2021. Lower debt levels have resulted in reduced financing and interest expense in both periods of 2022 relative to 2021.

Cash interest of $20.5 million ($2.71/boe) for Q2/2022 and $40.9 million ($2.76/boe) for YTD 2022 is lower than $23.6 million ($3.19/boe) for Q2/2021 and $48.0 million ($3.31/boe) for YTD 2021 as we had less debt outstanding during 2022. The interest on our U.S. dollar denominated long-term notes was lower as the average principal amount outstanding was lower during YTD 2022 due to the repurchase and redemption of US$200.0 million of long-term notes in 2021 and US$200.0 million of long-term notes in Q2/2022. Interest on our credit facilities in Q2/2022 and YTD 2022 was relatively consistent with the same periods of 2021. The weighted average interest rate applicable to our credit facilities was 2.8% for Q2/2022 and 2.6% for YTD 2022 which is slightly higher than 2.1% for Q2/2021 and YTD 2021 and consistent with the increase in benchmark borrowing rates.

Financing and interest expense for YTD 2022 was lower than YTD 2021 which was primarily the result of the repurchase and redemption of the 2024 senior notes and also reflects a higher discount rate used to accrete our asset retirement obligations in the first half of 2022.

Cash interest expense of $2.76/boe for YTD 2022 is above our annual guidance of $2.45/boe for 2022 as we expect a reduction in our net debt during the remainder of the year along with higher production.

EXPLORATION AND EVALUATION EXPENSE

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense was $7.2 million for Q2/2022 and $10.8 million for YTD 2022 compared to $3.0 million for Q2/2021 and $4.0 million for YTD 2021.

DEPLETION AND DEPRECIATION

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved plus probable reserves volumes and the rate of production for the period. The following table summarizes depletion and depreciation expense for the three and six months ended June 30, 2022 and 2021.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2022**	2021	Change	**2022**	2021	Change
Depletion	**$ 140,809**	$ 101,751	$ 39,058	**$ 280,255**	$ 202,490	$ 77,765
Depreciation	**1,477**	1,304	173	**2,822**	2,577	245
Depletion and depreciation	**$ 142,286**	$ 103,055	$ 39,231	**$ 283,077**	$ 205,067	$ 78,010
Depletion and depreciation per boe(1)	**$ 18.82**	$ 13.95	$ 4.87	**$ 19.08**	$ 14.17	$ 4.91

(1) Depletion and depreciation expense per boe is calculated as depletion and depreciation expense divided by barrels of oil equivalent production volume for the applicable period.

Depletion and depreciation expense was $142.3 million ($18.82/boe) for Q2/2022 and $283.1 million ($19.08/boe) for YTD 2022 compared to $103.1 million ($13.95/boe) for Q2/2021 and $205.1 million ($14.17/boe) for YTD 2021. Total depletion and depreciation expense as well as the depletion rate per boe were higher in both periods of 2022 relative to 2021 as a result of $1.5 billion of impairment reversals recorded during 2021 which increased the depletable base of our U.S. and Canadian assets.

IMPAIRMENT

We did not identify indicators of impairment or impairment reversal for any of our cash generating units ("CGU") at June 30, 2022.

2021 Impairment Reversals

We identified indicators of impairment reversal at June 30, 2021 and December 31, 2021 due to the increase in forecasted commodity prices in addition to changes in proved plus probable reserves and we recorded a total impairment reversal of $1.5 billion. At June 30, 2021 we recorded a $1.1 billion impairment reversal as the estimated recoverable amount of our six CGUs exceeded their carrying values. At December 31, 2021 we recorded a $0.4 billion impairment reversal as the estimated recoverable amount of three CGUs exceeded their carrying amounts.

SHARE-BASED COMPENSATION EXPENSE

Share-based compensation ("SBC") expense includes expense associated with our Share Award Incentive Plan, Incentive Award Plan, and Deferred Share Unit Plan. SBC expense associated with our Share Award Incentive Plan is recognized in net income or loss over the vesting period of the awards with a corresponding increase in contributed surplus. SBC expense associated with our Incentive Award Plan is recognized in net income or loss over the vesting period of the awards with a corresponding financial liability and includes gains or losses on equity total return swaps used to fix the aggregate cost of new grants made under the plan. SBC expense associated with the Deferred Share Unit Plan is recognized in net income or loss on the grant date with a corresponding financial liability and includes gains or losses on equity total return swaps used to fix the aggregate cost of new grants made under the plan. SBC expense varies with the quantity of unvested share awards outstanding and the grant date fair value assigned to the share awards.

We recorded SBC expense of $2.9 million for Q2/2022 and $6.9 million for YTD 2022 which is consistent with $2.8 million for Q2/2021 and $5.8 million for YTD 2021. The total expense for YTD 2022 is comprised of non-cash compensation expense of $2.1 million related to the Share Award Incentive Plan and cash compensation expense of $4.8 million related to the Incentive Award Plan and the Deferred Share Unit Plan.

FOREIGN EXCHANGE

Unrealized foreign exchange gains and losses are primarily a result of changes in the reported amount of our U.S. dollar denominated long-term notes and credit facilities in our Canadian functional currency entities. The long-term notes and credit facilities are translated to Canadian dollars on the balance sheet date using the closing CAD/USD exchange rate resulting in unrealized gains and losses. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in our Canadian functional currency entities.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for exchange rates)	**2022**	2021	Change	**2022**	2021	Change
Unrealized foreign exchange loss (gain)	**$ 27,499**	$ (1,792)	$ 29,291	**$ 12,951**	$ (4,322)	$ 17,273
Realized foreign exchange loss (gain)	**210**	(464)	674	**413**	(739)	1,152
Foreign exchange loss (gain)	**$ 27,709**	$ (2,256)	$ 29,965	**$ 13,364**	$ (5,061)	$ 18,425
CAD/USD exchange rates:						
At beginning of period	**1.2484**	1.2572		**1.2656**	1.2755	
At end of period	**1.2872**	1.2405		**1.2872**	1.2405	

We recorded a foreign exchange loss of $27.7 million for Q2/2022 and $13.4 million for YTD 2022 compared to a gain of $2.3 million for Q2/2021 and $5.1 million for YTD 2021.

The unrealized foreign exchange loss of $27.5 million for Q2/2022 and $13.0 million for YTD 2022 is primarily related to changes in the reported amount of our long-term notes and credit facilities due to a weakening of the Canadian dollar relative to the U.S. dollar at June 30, 2022 compared to March 31, 2022 and December 31, 2021. The unrealized foreign exchange gain for Q2/2021 and YTD 2021 relates to changes in the reported amount of our long-term notes and intercompany notes outstanding at June 30, 2021 compared to March 31, 2021 and December 31, 2020.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange loss of $0.2 million for Q2/2022 and $0.4 million for YTD 2022 compared to a gain of $0.5 million for Q2/2021 and $0.7 million for YTD 2021.

INCOME TAXES

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2022**	2021	Change	**2022**	2021	Change
Current income tax expense	**$ 1,140**	$ 568	$ 572	**$ 2,050**	$ 408	$ 1,642
Deferred income tax expense (recovery)	**39,920**	56,051	(16,131)	**(27,412)**	61,715	(89,127)
Total income tax expense (recovery)	**$ 41,060**	$ 56,619	$ (15,559)	**$ (25,362)**	$ 62,123	$ (87,485)

Current income tax expense was $1.1 million for Q2/2022 and $2.1 million for YTD 2022 compared to $0.6 million for Q2/2021 and $0.4 million for YTD 2021.

We recorded deferred tax expense of $39.9 million for Q2/2022 and a recovery of $27.4 million for YTD 2022 compared to expense of $56.1 million for Q2/2021 and $61.7 million for YTD 2021. The deferred tax recovery recorded in YTD 2022 is primarily related to the effect of an internal debt restructuring offset by the income generated in our U.S. operations for the period. The deferred tax expense for YTD 2021 reflects income generated in our U.S. operations for the period.

As disclosed in the 2021 annual financial statements, certain indirect subsidiaries received reassessments from the Canada Revenue Agency (the "CRA") that deny $591.0 million of non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. In September 2016, we filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to our file in July 2018. We remain confident that our original tax filings are correct and intend to defend these tax filings through the appeals process.

NET INCOME AND ADJUSTED FUNDS FLOW

The components of adjusted funds flow and net income or loss for the three and six months ended June 30, 2022 and 2021 are set forth in the following table.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2022**	2021	Change	**2022**	2021	Change
Petroleum and natural gas sales	**$ 854,169**	$ 442,354	$ 411,815	**$ 1,527,994**	$ 827,056	$ 700,938
Royalties	**(171,559)**	(81,531)	(90,028)	**(294,279)**	(148,481)	(145,798)
Revenue, net of royalties	**682,610**	360,823	321,787	**1,233,715**	678,575	555,140
Expenses						
Operating	**(107,426)**	(82,901)	(24,525)	**(208,192)**	(163,449)	(44,743)
Transportation	**(11,758)**	(7,486)	(4,272)	**(20,973)**	(16,274)	(4,699)
Blending and other	**(56,895)**	(19,967)	(36,928)	**(98,335)**	(37,087)	(61,248)
Operating netback (1)	**$ 506,531**	$ 250,469	$ 256,062	**$ 906,215**	$ 461,765	$ 444,450
General and administrative	**(11,640)**	(10,610)	(1,030)	**(23,322)**	(19,343)	(3,979)
Cash interest	**(20,474)**	(23,554)	3,080	**(40,901)**	(47,957)	7,056
Realized financial derivatives loss	**(124,042)**	(39,024)	(85,018)	**(208,408)**	(59,792)	(148,616)
Realized foreign exchange (loss) gain	**(210)**	464	(674)	**(413)**	739	(1,152)
Other (expense) income	**(751)**	(170)	(581)	**(1,001)**	62	(1,063)
Current income tax expense	**(1,140)**	(568)	(572)	**(2,050)**	(408)	(1,642)
Share-based compensation - cash	**(2,570)**	(1,124)	(1,446)	**(4,809)**	(2,601)	(2,208)
Adjusted funds flow (2)	**$ 345,704**	$ 175,883	$ 169,821	**$ 625,311**	$ 332,465	$ 292,846
Exploration and evaluation	**(7,210)**	(3,005)	(4,205)	**(10,780)**	(3,952)	(6,828)
Depletion and depreciation	**(142,286)**	(103,055)	(39,231)	**(283,077)**	(205,067)	(78,010)
Share-based compensation - non-cash	**(372)**	(1,646)	1,274	**(2,078)**	(3,150)	1,072
Non-cash financing and accretion	**(6,603)**	(3,800)	(2,803)	**(10,420)**	(6,847)	(3,573)
Non-cash other income	**183**	676	(493)	**1,465**	1,664	(199)
Unrealized financial derivatives gain (loss)	**58,768**	(84,483)	143,251	**(97,493)**	(170,467)	72,974
Unrealized foreign exchange (loss) gain	**(27,499)**	1,792	(29,291)	**(12,951)**	4,322	(17,273)
Gain on dispositions	**207**	274	(67)	**441**	3,980	(3,539)
Impairment reversal	**—**	1,126,414	(1,126,414)	**—**	1,126,414	(1,126,414)
Deferred income tax (expense) recovery	**(39,920)**	(56,051)	16,131	**27,412**	(61,715)	89,127
Net income for the period	**$ 180,972**	$ 1,052,999	$ (872,027)	**$ 237,830**	$ 1,017,647	$ (779,817)

(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 MD&A for further information.

(2) Capital management measure. Refer to the Specified Financial Measures section in this MD&A for further information.

We generated adjusted funds flow of $345.7 million for Q2/2022 and $625.3 million for YTD 2022 compared to $175.9 million for Q2/2021 and $332.5 million for YTD 2021. The increase in adjusted funds flow for both periods of 2022 was primarily due to higher operating netback which increased $256.1 million from Q2/2021 and $444.5 million from YTD 2021 as a result of higher commodity prices that increased revenue, net of royalties. The increase in operating netback was partially offset by realized losses on financial derivatives of $124.0 million for Q2/2022 and $208.4 million for YTD 2022 due to the increase in oil and natural gas benchmark prices relative to Q2/2021 and YTD 2021 when we recorded realized losses on financial derivatives of $39.0 million and $59.8 million respectively.

We reported net income of $181.0 million for Q2/2022 and $237.8 million for YTD 2022 compared to net income of $1.1 billion reported for Q2/2021 and $1.0 billion for YTD 2021. Net income was higher for both periods of 2021 as a result of an impairment reversal of $1.1 billion recorded in Q2/2021.

OTHER COMPREHENSIVE INCOME (LOSS)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets which is not recognized in net income or loss. The foreign currency translation gain of $58.9 million for Q2/2022 and $30.8 million for YTD 2022 relates to the change in value of our U.S. net assets and is due to weakening of the Canadian dollar relative to the U.S. dollar at June 30, 2022 compared to March 31, 2022 and December 31, 2021. The CAD/USD exchange rate was 1.2872 CAD/USD as at June 30, 2022 compared to 1.2484 CAD/USD at March 31, 2022 and 1.2656 CAD/USD at December 31, 2021.

CAPITAL EXPENDITURES

Capital expenditures for the three and six months ended June 30, 2022 and 2021 are summarized as follows.

	Three Months Ended June 30					
	2022			2021		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 37,265**	**$ 43,167**	**$ 80,432**	$ 23,018	$ 30,911	$ 53,929
Facilities	**6,912**	**1,414**	**8,326**	4,682	9	4,691
Land, seismic and other	**7,704**	**171**	**7,875**	2,687	178	2,865
Exploration and development expenditures	**$ 51,881**	**$ 44,752**	**$ 96,633**	$ 30,387	$ 31,098	$ 61,485
Property acquisitions	**$ 208**	**$ —**	**$ 208**	$ —	$ —	$ —
Proceeds from dispositions	**$ (14)**	**$ —**	**$ (14)**	$ (18)	$ —	$ (18)

	Six Months Ended June 30					
	2022			2021		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 144,263**	**$ 70,305**	**$ 214,568**	$ 62,052	$ 71,633	$ 133,685
Facilities	**14,678**	**1,800**	**16,478**	7,197	13	7,210
Land, seismic and other	**19,070**	**339**	**19,409**	3,641	537	4,178
Exploration and development expenditures	**$ 178,011**	**$ 72,444**	**$ 250,455**	$ 72,890	$ 72,183	$ 145,073
Property acquisitions	**$ 267**	**$ —**	**$ 267**	$ 25	$ —	$ 25
Proceeds from dispositions	**$ (41)**	**$ —**	**$ (41)**	$ (246)	$ —	$ (246)

Exploration and development expenditures were $96.6 million for Q2/2022 and $250.5 million for YTD 2022 compared to $61.5 million for Q2/2021 and $145.1 million for YTD 2021. Expenditures in Q2/2022 were higher compared to Q2/2021 as development increased throughout 2021 with the strengthening of commodity prices that continued into 2022.

In Canada, exploration and development expenditures were $51.9 million in Q2/2022 and $178.0 million in YTD 2022 compared to $30.4 million in Q2/2021 and $72.9 million in YTD 2021. Drilling and completion spending of $37.3 million in Q2/2022 and $144.3 million in YTD 2022 reflects higher light and heavy oil development activity relative to Q2/2021 and YTD 2021 when we spent $23.0 million and $62.1 million respectively. We also invested $6.9 million on facilities and $7.7 million on land, seismic and other expenditures during Q2/2022.

Total U.S. exploration and development expenditures were $44.8 million for Q2/2022 and $72.4 million for YTD 2022 compared to $31.1 million in Q2/2021 and $72.2 million during YTD 2021. Exploration and development expenditures for Q2/2022 included costs associated with drilling 23 (7.4 net) wells along with 20 (3.8 net) wells that were brought on production compared to drilling 16 (1.7 net) wells along with 38 (10.2 net) wells brought on production during Q2/2021. Lower development activity in YTD 2022 was offset by inflationary pressures along with a weaker Canadian dollar which resulted in exploration and development expenditures of $72.4 million which are consistent with $72.2 million for YTD 2021.

Our exploration and development expenditures for YTD 2022 are consistent with expectations and we expect full year expenditures to be at the high end of our annual guidance of $450 - $500 million for 2022.

CAPITAL RESOURCES AND LIQUIDITY

Our objective for capital management is to maintain a flexible capital structure and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions. At June 30, 2022, our capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables and the credit facilities.

In order to manage our capital structure and liquidity, we may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

The capital intensive nature of our operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties.

Management of debt levels is a priority for us in order to sustain operations and support our long-term plans. At June 30, 2022, net debt(1) of $1.12 billion was $286.4 million lower than $1.41 billion at December 31, 2021. The decrease in net debt for 2022 is primarily a result of the free cash flow(2) of $366.6 million generated during 2022 being allocated to debt repayment which was partially offset by $62.5 million in common share repurchases completed in conjunction with our shareholder returns initiative.

In May 2022, we began repurchasing its common shares under a previously announced normal course issuer bid as part of its shareholder return framework. During Q2/2022 we repurchased and cancelled 9.1 million common shares, representing 1.6% of our total shares outstanding for $62.5 million.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio calculated on a trailing twelve month basis. At June 30, 2022, our net debt to adjusted funds flow ratio(1) was 1.1 compared to a ratio of 1.9 as at December 31, 2021. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2021 is attributed to higher adjusted funds flow for the trailing twelve months ended June 30, 2022 and lower net debt at June 30, 2022.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A 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 MD&A for further information.

Credit Facilities

At June 30, 2022, the principal amount of borrowings and letters of credit outstanding was $512.1 million under our Credit Facilities. On April 1, 2022, we amended the Credit Facilities to expand our revolving facilities to US$850 million and extend maturity to April 1, 2026. The term loan facility was also eliminated as part of this amendment.

The Credit Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. There are no mandatory principal payments required prior to maturity which could be extended upon our request. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. Advances (including letters of credit) under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank’s prime lending rate, bankers’ acceptance discount rates or secured overnight financing rates ("SOFR"), plus applicable margins.

The agreements and associated amending agreements relating to the Credit Facilities are accessible on the SEDAR website at www.sedar.com.

The weighted average interest rate on the Credit Facilities was 2.8% for Q2/2022 and 2.6% for YTD 2022 compared to 2.1% for Q2/2021 and YTD 2021. The interest rate on our Credit Facilities has increased with higher government benchmark rates in 2022 relative to 2021.

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at June 30, 2022.

Covenant Description	Postion as at June 30, 2022	Covenant
Senior Secured Debt [1] to Bank EBITDA [2] (Maximum Ratio)	**0.5:1.0**	3.5:1.0
Interest Coverage [3] (Minimum Ratio)	**13.3:1.0**	2.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the credit facility agreements and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit agreement. As at June 30, 2022, the Company's Senior Secured Debt totaled $512.1 million which includes $496.9 million of principal amounts outstanding and $15.1 million of letters of credit.

(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended June 30, 2022 was $1.1 billion.

(3) "Interest coverage" is calculated in accordance with the credit agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expenses for the twelve months ended June 30, 2022 were $84.8 million.

Long-Term Notes

We have one series of long-term notes outstanding that totals $643.6 million as at June 30, 2022. The long-term notes do not contain any financial maintenance covenants.

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the "5.125% Notes"), and US$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"). We redeemed the 5.125% Notes on February 20, 2020. During 2021, we redeemed and cancelled US$200 million of the 5.625% Notes and on June 1, 2022, we redeemed and canceled the remaining US$200 million of the 5.625% Notes at par.

On February 5, 2020, we issued US$500 million aggregate principal amount of senior unsecured notes due April 1, 2027 bearing interest at a rate of 8.75% per annum payable semi-annually (the "8.75% Senior Notes"). The 8.75% Senior Notes are redeemable at our option, in whole or in part, at specified redemption prices after April 1, 2023 and will be redeemable at par from April 1, 2026 to maturity.

Shareholders’ Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the six months ended June 30, 2022, we issued 5.0 million common shares pursuant to our share-based compensation program and cancelled 9.1 million common shares repurchased under a normal course issuer bid. As at June 30, 2022, we had 560.1 million common shares issued and outstanding and no preferred shares issued and outstanding.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of June 30, 2022 and the expected timing for funding these obligations are noted in the table below.

($ thousands)	**Total**	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 309,163**	$ 309,163	$ —	$ —	$ —
Financial derivatives	**240,838**	228,289	12,549	—	—
Credit facilities - principal (1)(2)	**496,917**	—	—	496,917	—
Long-term notes - principal (2)	**643,600**	—	—	643,600	—
Interest on long-term notes (3)	**267,843**	56,315	112,630	98,898	—
Lease obligations (2)	**7,474**	3,319	3,816	262	77
Processing agreements	**7,315**	1,251	1,377	896	3,791
Transportation agreements	**71,018**	19,826	31,907	14,673	4,612
Total	**$ 2,044,168**	$ 618,163	$ 162,279	$ 1,255,246	$ 8,480

(1) On April 1, 2022 we extended the maturity of our credit facilities to April 1, 2026.
(2) Principal amount of instruments.
(3) Excludes interest on our credit facilities as interest payments fluctuate based on a floating rate of interest and changes in the outstanding balances.

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities when they reach the end of their economic lives. Programs to abandon and reclaim well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

QUARTERLY FINANCIAL INFORMATION

($ thousands, except per common share amounts)	2022 Q2	2022 Q1	2021 Q4	2021 Q3	2021 Q2	2021 Q1	2020 Q4	2020 Q3
Petroleum and natural gas sales	**854,169**	673,825	552,403	488,736	442,354	384,702	233,636	252,538
Net income (loss)	**180,972**	56,858	563,239	32,714	1,052,999	(35,352)	221,160	(23,444)
Per common share - basic	**0.32**	0.10	1.00	0.06	1.87	(0.06)	0.39	(0.04)
Per common share - diluted	**0.32**	0.10	0.98	0.06	1.85	(0.06)	0.39	(0.04)
Adjusted funds flow (1)	**345,704**	279,607	214,766	198,397	175,883	156,582	82,176	78,508
Per common share - basic	**0.61**	0.49	0.38	0.35	0.31	0.28	0.15	0.14
Per common share - diluted	**0.60**	0.49	0.37	0.35	0.31	0.28	0.15	0.14
Free cash flow (2)	**245,316**	121,318	137,133	101,215	112,486	70,495	1,794	59,939
Per common share - basic	**0.43**	0.21	0.24	0.18	0.20	0.13	—	0.11
Per common share - diluted	**0.43**	0.21	0.24	0.18	0.20	0.13	—	0.11
Cash flows from operating activities	**360,034**	198,974	240,567	178,961	171,876	120,980	51,017	93,688
Per common share - basic	**0.63**	0.35	0.43	0.32	0.30	0.22	0.09	0.17
Per common share - diluted	**0.63**	0.35	0.42	0.31	0.30	0.22	0.09	0.17
Exploration and development	**96,633**	153,822	73,995	94,235	61,485	83,588	77,809	15,902
Canada	**51,881**	126,130	59,821	75,499	30,387	42,503	45,030	3,882
U.S.	**44,752**	27,692	14,174	18,736	31,098	41,085	32,779	12,020
Property acquisitions	**208**	59	1,443	89	—	25	—	—
Proceeds from dispositions	**(14)**	(27)	(6,857)	(701)	(18)	(228)	(33)	(98)
Net debt (1)	**1,123,297**	1,275,680	1,409,717	1,564,658	1,629,629	1,758,894	1,847,601	1,906,079
Total assets	**4,810,150**	4,836,189	4,834,643	4,453,971	4,438,162	3,338,408	3,408,096	3,156,414
Common shares outstanding	**560,139**	569,214	564,213	564,213	564,182	564,111	561,227	561,163
Daily production								
Total production (boe/d)	**83,090**	80,867	80,789	79,872	81,162	78,780	70,475	77,814
Canada (boe/d)	**54,919**	53,385	50,362	48,124	47,205	52,039	45,321	49,164
U.S. (boe/d)	**28,170**	27,482	30,428	31,748	33,957	26,741	25,154	28,650
Benchmark prices								
WTI oil (US$/bbl)	**108.41**	94.29	77.19	70.56	66.07	57.84	42.66	40.93
WCS heavy oil ($/bbl)	**122.05**	100.99	78.82	71.81	67.03	57.46	43.46	42.40
Edmonton par oil ($/bbl)	**137.79**	115.66	93.29	83.78	77.28	66.58	50.24	49.83
CAD/USD avg exchange rate	**1.2766**	1.2661	1.2600	1.2601	1.2279	1.2663	1.3031	1.3316
AECO natural gas ($/mcf)	**6.27**	4.59	4.94	3.54	2.85	2.93	2.77	2.18
NYMEX natural gas (US$/mmbtu)	**7.17**	4.95	5.83	4.01	2.83	2.69	2.66	1.98
Total sales, net of blending and other expense ($/boe) (2)	**105.44**	86.89	70.42	63.85	57.19	51.84	34.35	33.79
Royalties ($/boe) (3)	**(22.69)**	(16.86)	(13.47)	(12.32)	(11.04)	(9.44)	(5.83)	(5.59)
Operating expense ($/boe) (3)	**(14.21)**	(13.85)	(12.83)	(11.46)	(11.22)	(11.36)	(12.30)	(10.26)
Transportation expense ($/boe) (3)	**(1.56)**	(1.27)	(1.10)	(1.06)	(1.01)	(1.24)	(1.03)	(0.89)
Operating netback ($/boe) (2)	**66.98**	54.91	43.02	39.01	33.92	29.80	15.19	17.05
Financial derivatives (loss) gain ($/boe) (3)	**(16.41)**	(11.59)	(9.49)	(7.34)	(5.28)	(2.93)	2.64	(1.36)
Operating netback after financial derivatives ($/boe) (2)	**50.57**	43.32	33.53	31.67	28.64	26.87	17.83	15.69

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A 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 MD&A for further information.

(3) Calculated as royalties expense, operating expense, transportation expense or financial derivatives gain or loss divided by barrels of oil equivalent production volume for the applicable period.

Our results for the previous eight quarters reflect the disciplined execution of our development programs and management of production in response to fluctuations in the prices for the commodities we produce. Production of 77,814 boe/d in Q3/2020 and 70,475 boe/d in Q4/2020 reflect our efforts to manage production levels in response to volatile commodity prices caused by the start of the COVID-19 pandemic. Development activity increased as commodity prices began to climb in Q1/2021 and we have continued the pace of activity as commodity prices improved throughout 2021 and 2022. Strong well performance and our successful development programs have resulted in production of 83,090 boe/d for Q2/2022.

Prices improved and were relatively stable through the second half of 2020 as OPEC+ agreed to reinstate production curtailments and measures to control the spread of COVID-19 were relaxed. Commodity prices strengthened throughout 2021 and reached multi-year highs in 2022 with WTI averaging US$108.41/bbl during Q2/2022 due to elevated uncertainty for the global supply of oil following Russia's invasion of Ukraine in addition to limited production growth due to producers' capital discipline. The impact of increased commodity prices is reflected in our realized sales price of $105.44/boe for Q2/2022 which is our strongest realized pricing in the previous eight quarters.

Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow(1) of $345.7 million for Q2/2022 was the highest quarterly result in the last two years due to strong price realizations which reflect the increase in benchmark commodity prices over the previous eight quarters.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt(1) has decreased from $1.9 billion at Q3/2020 to $1.1 billion at Q2/2022 as free cash flow(2) of $849.7 million generated over the last eight quarters has been directed towards debt repayment. The decrease in net debt due to free cash flow was partially offset by our shareholder return initiative which was implemented during Q2/2022 and resulted in the repurchase and cancellation of 9.1 million common shares for total consideration of $62.5 million.

(1) Capital management measure. Refer to the Specified Financial Measures section in this MD&A 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 MD&A for further information.

ENVIRONMENTAL REGULATIONS

As a result of our involvement in the exploration for and production of oil and natural gas we are subject to various emissions, carbon and other environmental regulations. Refer to the AIF for the year ended December 31, 2021 for a full description of the risks associated with these regulations and how they may impact our business in the future. In addition to the Risk Factors discussed in the AIF for the year ended December 31, 2021, additional information related to our emissions and sustainability initiatives is available on our website.

Reporting Regulations

Environmental reporting for public enterprises continues to evolve and we may be subject to additional future disclosure requirements. The International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the objective to develop a global framework for environmental sustainability disclosure. The Canadian Securities Administrators have also issued a proposed National Instrument 51-107 *Disclosure of Climate-related Matters* which sets forth additional reporting requirements for Canadian Public Companies. We continue to monitor developments on these reporting requirements and have not yet quantified the cost to comply with these regulations.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at June 30, 2022, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the six months ended June 30, 2022. Further information on our critical accounting policies and estimates can be found in the notes to the audited annual consolidated financial statements and MD&A for the year ended December 31, 2021.

SPECIFIED FINANCIAL MEASURES

In this MD&A, we refer to certain specified financial measures (such as free cash flow, operating netback, total sales, net of blending and other expense, heavy oil sales, net of blending and other expense, and average royalty rate) which do not have any standardized meaning prescribed by IFRS. While these measures are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. This MD&A also contains the terms "adjusted funds flow", "net debt" and "net debt to adjusted funds flow ratio" which are 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 and operating netback after financial derivatives are 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. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

The following table reconciles operating netback and operating netback after realized financial derivatives to petroleum and natural gas sales.

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2022**	2021	**2022**	2021
Petroleum and natural gas sales	**$ 854,169**	$ 442,354	**$ 1,527,994**	$ 827,056
Blending and other expense	**(56,895)**	(19,967)	**(98,335)**	(37,087)
Total sales, net of blending and other expense	**797,274**	422,387	**1,429,659**	789,969
Royalties	**(171,559)**	(81,531)	**(294,279)**	(148,481)
Operating expense	**(107,426)**	(82,901)	**(208,192)**	(163,449)
Transportation expense	**(11,758)**	(7,486)	**(20,973)**	(16,274)
Operating netback	**506,531**	250,469	**906,215**	461,765
Realized financial derivatives loss (1)	**(124,042)**	(39,024)	**(208,408)**	(59,792)
Operating netback after realized financial derivatives	**$ 382,489**	$ 211,445	**$ 697,807**	$ 401,973

(1) *Realized financial derivatives gain or loss is a component of financial derivatives gain or loss. See Note 16 - Financial Instruments and Risk Management in the consolidated financial statements for the three and six months ended June 30, 2022 for further information.*

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.

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2022**	2021	**2022**	2021
Cash flows from operating activities	**$ 360,034**	$ 171,876	**$ 559,008**	$ 292,856
Change in non-cash working capital	**(17,046)**	3,014	**60,294**	$ 37,199
Additions to exploration and evaluation assets	**(2,338)**	(428)	**(5,897)**	(644)
Additions to oil and gas properties	**(94,295)**	(61,057)	**(244,558)**	(144,429)
Payments on lease obligations	**(1,039)**	(919)	**(2,213)**	(2,001)
Free cash flow	**$ 245,316**	$ 112,486	**$ 366,634**	$ 182,981

Non-GAAP Financial Ratios

Heavy oil, net of blending and other expense per bbl

Heavy oil, net of blending and other expense per bbl represents the realized price for produced heavy oil volumes during a period. Heavy oil, net of blending and other expense is a non-GAAP financial ratio that is divided by barrels of heavy oil production volume for the applicable period to calculate the ratio. We use heavy oil, net of blending and other expense per bbl to analyze our realized heavy oil price for produced volumes against the WCS benchmark price.

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 operating netback (a non-GAAP financial measure) divided by barrels of oil equivalent production volume for the applicable period and is used to assess our operating performance on a unit of production basis. Realized financial derivative gains and losses per boe are added to operating netback per boe to arrive at operating netback after financial derivatives per boe. Realized financial derivatives gains and losses are added to operating netback to provide a more complete picture of our financial performance as our financial derivatives are used to provide price certainty on a portion of our production.

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. We also use a net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis to monitor our existing capital structure and future liquidity requirements. Net debt to adjusted funds flow is comprised of net debt divided by twelve-month trailing adjusted funds flow.

The following table summarizes our calculation of net debt.

($ thousands)		**June 30, 2022**		December 31, 2021
Credit facilities	**$**	**494,410**	$	505,171
Unamortized debt issuance costs - Credit facilities [(1)]		**2,507**		1,343
Long-term notes		**634,758**		874,527
Unamortized debt issuance costs - Long-term notes [(1)]		**8,842**		11,393
Trade and other payables		**309,163**		190,692
Trade and other receivables		**(326,383)**		(173,409)
Net debt	**$**	**1,123,297**	$	1,409,717
Net debt to adjusted funds flow		**1.1**		1.9

(1) Unamortized debt issuance costs were obtained from Note 6 - Credit Facilities and Note 7 - Long-term Notes from the consolidated financial statements for the three and six months ended June 30, 2022. These amounts represent the remaining balance of costs that were paid by Baytex at the inception of the contract.

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.

	Three Months Ended June 30				Six Months Ended June 30			
($ thousands)		**2022**		2021		**2022**		2021
Cash flow from operating activities	**$**	**360,034**	$	171,876	**$**	**559,008**	$	292,856
Change in non-cash working capital		**(17,046)**		3,014		**60,294**		37,199
Asset retirement obligations settled		**2,716**		993		**6,009**		2,410
Adjusted funds flow	**$**	**345,704**	$	175,883	**$**	**625,311**	$	332,465

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended June 30, 2022.

FORWARD-LOOKING STATEMENTS

In the interest of providing our shareholders and potential investors with information regarding Baytex, including management's assessment of the Company's future plans and operations, certain statements in this document 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 "anticipate", "believe", "continue", "could", "estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "plan", "project", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this document speak only as of the date of this document and are expressly qualified by this cautionary statement.

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our 2022 guidance with respect to exploration and development expenditures, average daily production, royalty rate and operating, transportation, general and administrative and interest expenses; the existence, operation and strategy of our risk management program; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; and the manner in which we fund our planned capital expenditures and monitor and manage our capital resources and liquidity; we may issue debt or equity securities, sell assets or adjust capital spending.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices (well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); restrictions or costs imposed by climate change initiatives and the physical risks of climate change; risks associated with our ability to develop our properties and add reserves; the impact of an energy transition on demand for petroleum productions; changes in income tax or other laws or government incentive programs; availability and cost of gathering, processing and pipeline systems; retaining or replacing our leadership and key personnel; the availability and cost of capital or borrowing; risks associated with a third-party operating our Eagle Ford properties; risks associated with large projects; costs to develop and operate our properties; public perception and its influence on the regulatory regime; current or future control, legislation or regulations; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; regulations regarding the disposal of fluids; risks associated with our hedging activities; variations in interest rates and foreign exchange rates; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; additional risks associated with our thermal heavy oil projects; our ability to compete with other organizations in the oil and gas industry; risks associated with our use of information technology systems; results of litigation; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks of counterparty default; the impact of Indigenous claims; risks associated with expansion into new activities; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2021, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

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.

Baytex Energy Corp.
Condensed Consolidated Interim Statements of Financial Position
(thousands of Canadian dollars) (unaudited)

	Notes	As at June 30, 2022	As at December 31, 2021
ASSETS			
Current assets			
Trade and other receivables		**$ 326,383**	$ 173,409
Financial derivatives	16	**17,979**	8,654
		344,362	182,063
Non-current assets			
Exploration and evaluation assets	4	**163,811**	172,824
Oil and gas properties	5	**4,287,087**	4,464,371
Other plant and equipment		**6,994**	7,121
Lease assets		**7,896**	8,264
		$ 4,810,150	$ 4,834,643
LIABILITIES			
Current liabilities			
Trade and other payables		**$ 309,163**	$ 190,692
Financial derivatives	16	**228,289**	134,020
Lease obligations		**3,177**	2,938
Asset retirement obligations	8	**10,929**	11,080
		551,558	338,730
Non-current liabilities			
Financial derivatives	16	**12,549**	—
Credit facilities	6	**494,410**	505,171
Long-term notes	7	**634,758**	874,527
Lease obligations		**4,068**	4,827
Asset retirement obligations	8	**551,231**	732,603
Deferred income tax liability	13	**141,965**	167,456
		2,390,539	2,623,314
SHAREHOLDERS’ EQUITY			
Shareholders' capital	9	**5,653,883**	5,736,593
Contributed surplus		**35,883**	13,559
Accumulated other comprehensive income		**662,941**	632,103
Deficit		**(3,933,096)**	(4,170,926)
		2,419,611	2,211,329
		$ 4,810,150	$ 4,834,643

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated Interim Statements of Income and Comprehensive Income
(thousands of Canadian dollars, except per common share amounts and weighted average common shares) (unaudited)

		Three Months Ended June 30		Six Months Ended June 30	
	Notes	**2022**	2021	**2022**	2021
Revenue, net of royalties					
Petroleum and natural gas sales	12	**$ 854,169**	$ 442,354	**$ 1,527,994**	$ 827,056
Royalties		**(171,559)**	(81,531)	**(294,279)**	(148,481)
		682,610	360,823	**1,233,715**	678,575
Expenses					
Operating		**107,426**	82,901	**208,192**	163,449
Transportation		**11,758**	7,486	**20,973**	16,274
Blending and other		**56,895**	19,967	**98,335**	37,087
General and administrative		**11,640**	10,610	**23,322**	19,343
Exploration and evaluation	4	**7,210**	3,005	**10,780**	3,952
Depletion and depreciation		**142,286**	103,055	**283,077**	205,067
Impairment reversal	5	**—**	(1,126,414)	**—**	(1,126,414)
Share-based compensation	10	**2,942**	2,770	**6,887**	5,751
Financing and interest	14	**27,077**	27,354	**51,321**	54,804
Financial derivatives loss	16	**65,274**	123,507	**305,901**	230,259
Foreign exchange loss (gain)	15	**27,709**	(2,256)	**13,364**	(5,061)
Gain on dispositions		**(207)**	(274)	**(441)**	(3,980)
Other expense (income)		**568**	(506)	**(464)**	(1,726)
		460,578	(748,795)	**1,021,247**	(401,195)
Net income before income taxes		**222,032**	1,109,618	**212,468**	1,079,770
Income tax expense (recovery)	13				
Current income tax expense		**1,140**	568	**2,050**	408
Deferred income tax expense (recovery)		**39,920**	56,051	**(27,412)**	61,715
		41,060	56,619	**(25,362)**	62,123
Net income		**$ 180,972**	$ 1,052,999	**$ 237,830**	$ 1,017,647
Other comprehensive income (loss)					
Foreign currency translation adjustment		**58,917**	(107)	**30,838**	(7,206)
Comprehensive income		**$ 239,889**	$ 1,052,892	**$ 268,668**	$ 1,010,441
Net income per common share	11				
Basic		**$ 0.32**	$ 1.87	**$ 0.42**	$ 1.81
Diluted		**$ 0.32**	$ 1.85	**$ 0.42**	$ 1.79
Weighted average common shares (000's)	11				
Basic		**566,997**	564,156	**566,262**	563,126
Diluted		**571,697**	569,931	**570,844**	568,115

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated Interim Statements of Changes in Equity
(thousands of Canadian dollars) (unaudited)

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	Total equity
Balance at December 31, 2020		$ 5,729,418	$ 14,345	$ 618,976	$ (5,784,526)	**$ 578,213**
Vesting of share awards		7,100	(7,100)	—	—	**—**
Share-based compensation		—	3,150	—	—	**3,150**
Comprehensive income (loss)		—	—	(7,206)	1,017,647	**1,010,441**
Balance at June 30, 2021		$ 5,736,518	$ 10,395	$ 611,770	$ (4,766,879)	**$ 1,591,804**
Balance at December 31, 2021		$ 5,736,593	$ 13,559	$ 632,103	$ (4,170,926)	**$ 2,211,329**
Vesting of share awards	9	8,429	(8,429)	—	—	**—**
Share-based compensation	10	—	2,078	—	—	**2,078**
Repurchase of common shares for cancellation	9	(91,139)	28,675	—	—	**(62,464)**
Comprehensive income		—	—	30,838	237,830	**268,668**
Balance at June 30, 2022		$ 5,653,883	$ 35,883	$ 662,941	$ (3,933,096)	**$ 2,419,611**

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated Interim Statements of Cash Flows
(thousands of Canadian dollars) (unaudited)

		Three Months Ended June 30		Six Months Ended June 30	
	Notes	**2022**	2021	**2022**	2021
CASH PROVIDED BY (USED IN):					
Operating activities					
Net income		**$ 180,972**	$ 1,052,999	**$ 237,830**	$ 1,017,647
Adjustments for:					
Share-based compensation	10	**372**	1,646	**2,078**	3,150
Unrealized foreign exchange loss (gain)	15	**27,499**	(1,792)	**12,951**	(4,322)
Exploration and evaluation	4	**7,210**	3,005	**10,780**	3,952
Depletion and depreciation		**142,286**	103,055	**283,077**	205,067
Impairment reversal	5	**—**	(1,126,414)	**—**	(1,126,414)
Non-cash financing and accretion	14	**6,603**	3,800	**10,420**	6,847
Non-cash other income	8	**(183)**	(676)	**(1,465)**	(1,664)
Unrealized financial derivatives (gain) loss	16	**(58,768)**	84,483	**97,493**	170,467
Gain on dispositions		**(207)**	(274)	**(441)**	(3,980)
Deferred income tax expense (recovery)	13	**39,920**	56,051	**(27,412)**	61,715
Asset retirement obligations settled	8	**(2,716)**	(993)	**(6,009)**	(2,410)
Change in non-cash working capital		**17,046**	(3,014)	**(60,294)**	(37,199)
		360,034	171,876	**559,008**	292,856
Financing activities					
Increase (decrease) in credit facilities		**62,791**	(117,939)	**(15,351)**	(160,660)
Debt issuance costs		**(1,832)**	—	**(1,832)**	—
Payments on lease obligations		**(1,039)**	(919)	**(2,213)**	(2,001)
Redemption of long-term notes	7	**(252,830)**	(6,787)	**(252,830)**	(6,787)
Repurchase of common shares	9	**(62,464)**	—	**(62,464)**	—
		(255,374)	(125,645)	**(334,690)**	(169,448)
Investing activities					
Additions to exploration and evaluation assets	4	**(2,338)**	(428)	**(5,897)**	(644)
Additions to oil and gas properties	5	**(94,295)**	(61,057)	**(244,558)**	(144,429)
Additions to other plant and equipment		**(260)**	(320)	**(634)**	(411)
Property acquisitions		**(208)**	—	**(267)**	(25)
Proceeds from dispositions		**14**	18	**41**	246
Change in non-cash working capital		**(7,573)**	16,931	**26,997**	23,230
		(104,660)	(44,856)	**(224,318)**	(122,033)
Change in cash		**—**	1,375	**—**	1,375
Cash, beginning of period		**—**	—	**—**	—
Cash, end of period		**$ —**	$ 1,375	**$ —**	$ 1,375
Supplementary information					
Interest paid		**$ 11,181**	$ 16,764	**$ 41,529**	$ 47,601
Income taxes paid		**$ 263**	$ —	**$ 263**	$ —

See accompanying notes to the condensed consolidated interim financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the “Company” or “Baytex”) is an energy company engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and Texas, United States. The Company’s common shares are traded on the Toronto Stock Exchange under the symbol BTE. The Company’s head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PRESENTATION

The condensed consolidated interim financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). These condensed consolidated financial statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with the annual consolidated financial statements as at and for the year ended December 31, 2021.

The consolidated financial statements were approved by the Board of Directors of Baytex on July 27, 2022.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company. References to “US$” are to United States ("U.S.") dollars. All financial information is rounded to the nearest thousand, except per share amounts or when otherwise indicated.

The audited consolidated financial statements of the Company as at and for the year ended December 31, 2021 are available through its filings on SEDAR at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov.

Significant Accounting Policies

The accounting policies, critical accounting judgments and significant estimates used in preparation of the 2021 annual financial statements have been applied in the preparation of these consolidated financial statements, except for the adoption of *Normal Course Issue Bid ("NCIB") Share Repurchases* as described below.

Current Environment and Estimation Uncertainty

Management makes judgements and assumptions about the future in deriving estimates used in preparation of these consolidated financial statements in accordance with IFRS. Sources of estimation uncertainty include estimates used to determine economically recoverable oil, natural gas, and natural gas liquids reserves, the recoverable amount of long-lived assets or cash generating units, the fair value of financial derivatives, the provision for asset retirement obligations and the provision for income taxes and the related deferred tax assets and liabilities.

During the six months ended June 30, 2022, demand for oil and natural gas improved as the global economy continued to recover from the COVID-19 pandemic. Energy prices strengthened to multi-year highs due to elevated uncertainty of global oil and natural gas supply after Russia's invasion of Ukraine in addition to limited production growth reflecting oil and gas producers' capital discipline. While we have benefited from these improvements in crude oil prices, there is uncertainty related to COVID-19 and geopolitical events that have been considered in our estimates as at and for the period ended June 30, 2022.

Normal Course Issuer Bid ("NCIB") Share Repurchases

On May 2, 2022, Baytex announced the acceptance from the Toronto Stock Exchange (TSX) for implementation of a normal course issuer bid ("NCIB") under which Baytex is permitted to purchase for cancellation a specified number of common shares over a specified time frame. The shares repurchased and cancelled are accounted for as a reduction in Share Capital at historical cost, with any discount paid recorded to Contributed Surplus and any premium paid recorded to Retained Earnings. Total consideration paid includes any commissions or fees paid as part of the transaction.

3. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the geographic location and nature of the underlying operations:

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada;
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the U.S.; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended June 30	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 581,197**	$ 254,026	**$ 272,972**	$ 188,328	**$ —**	$ —	**$ 854,169**	$ 442,354
Royalties	**(91,133)**	(26,193)	**(80,426)**	(55,338)	**—**	—	**(171,559)**	(81,531)
	490,064	227,833	**192,546**	132,990	**—**	—	**682,610**	360,823
Expenses								
Operating	**82,471**	61,793	**24,955**	21,108	**—**	—	**107,426**	82,901
Transportation	**11,758**	7,486	**—**	—	**—**	—	**11,758**	7,486
Blending and other	**56,895**	19,967	**—**	—	**—**	—	**56,895**	19,967
General and administrative	**—**	—	**—**	—	**11,640**	10,610	**11,640**	10,610
Exploration and evaluation	**7,210**	3,005	**—**	—	**—**	—	**7,210**	3,005
Depletion and depreciation	**100,712**	63,088	**40,097**	38,663	**1,477**	1,304	**142,286**	103,055
Impairment reversal	**—**	(684,000)	**—**	(442,414)	**—**	—	**—**	(1,126,414)
Share-based compensation	**—**	—	**—**	—	**2,942**	2,770	**2,942**	2,770
Financing and interest	**—**	—	**—**	—	**27,077**	27,354	**27,077**	27,354
Financial derivatives loss	**—**	—	**—**	—	**65,274**	123,507	**65,274**	123,507
Foreign exchange loss (gain)	**—**	—	**—**	—	**27,709**	(2,256)	**27,709**	(2,256)
Gain on dispositions	**(207)**	(274)	**—**	—	**—**	—	**(207)**	(274)
Other (income) expense	**(183)**	(676)	**—**	—	**751**	170	**568**	(506)
	258,656	(529,611)	**65,052**	(382,643)	**136,870**	163,459	**460,578**	(748,795)
Net income (loss) before income taxes	**231,408**	757,444	**127,494**	515,633	**(136,870)**	(163,459)	**222,032**	1,109,618
Income tax expense								
Current income tax expense							**1,140**	568
Deferred income tax expense							**39,920**	56,051
							41,060	56,619
Net income (loss)	**$ 231,408**	$ 757,444	**$ 127,494**	$ 515,633	**$ (136,870)**	$ (163,459)	**$ 180,972**	$ 1,052,999
Additions to exploration and evaluation assets	**2,338**	428	**—**	—	**—**	—	**2,338**	428
Additions to oil and gas properties	**49,543**	29,959	**44,752**	31,098	**—**	—	**94,295**	61,057
Property acquisitions	**208**	—	**—**	—	**—**	—	**208**	—
Proceeds from dispositions	**(14)**	(18)	**—**	—	**—**	—	**(14)**	(18)

	Canada		U.S.		Corporate		Consolidated	
Six Months Ended June 30	**2022**	2021	**2022**	2021	**2022**	2021	**2022**	2021
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 1,034,901**	$ 493,448	**$ 493,093**	$ 333,608	**$ —**	$ —	**$ 1,527,994**	$ 827,056
Royalties	**(148,809)**	(50,857)	**(145,470)**	(97,624)	**—**	—	**(294,279)**	(148,481)
	886,092	442,591	**347,623**	235,984	**—**	—	**1,233,715**	678,575
Expenses								
Operating	**161,011**	123,154	**47,181**	40,295	**—**	—	**208,192**	163,449
Transportation	**20,973**	16,274	**—**	—	**—**	—	**20,973**	16,274
Blending and other	**98,335**	37,087	**—**	—	**—**	—	**98,335**	37,087
General and administrative	**—**	—	**—**	—	**23,322**	19,343	**23,322**	19,343
Exploration and evaluation	**10,780**	3,952	**—**	—	**—**	—	**10,780**	3,952
Depletion and depreciation	**201,794**	133,562	**78,461**	68,928	**2,822**	2,577	**283,077**	205,067
Impairment reversal	**—**	(684,000)	**—**	(442,414)	**—**	—	**—**	(1,126,414)
Share-based compensation	**—**	—	**—**	—	**6,887**	5,751	**6,887**	5,751
Financing and interest	**—**	—	**—**	—	**51,321**	54,804	**51,321**	54,804
Financial derivatives loss	**—**	—	**—**	—	**305,901**	230,259	**305,901**	230,259
Foreign exchange loss (gain)	**—**	—	**—**	—	**13,364**	(5,061)	**13,364**	(5,061)
Gain on dispositions	**(441)**	(3,980)		—	**—**	—	**(441)**	(3,980)
Other (income) expense	**(1,465)**	(1,664)		—	**1,001**	(62)	**(464)**	(1,726)
	490,987	(375,615)	**125,642**	(333,191)	**404,618**	307,611	**1,021,247**	(401,195)
	395,105	818,206	**221,981**	569,175	**(404,618)**	(307,611)	**212,468**	1,079,770
Income tax expense (recovery)								
Current income tax expense							**2,050**	408
Deferred income tax (recovery) expense							**(27,412)**	61,715
							(25,362)	62,123
Net income (loss)	**$ 395,105**	$ 818,206	**$ 221,981**	$ 569,175	**$ (404,618)**	$ (307,611)	**$ 237,830**	$ 1,017,647
Additions to exploration and evaluation assets	**5,897**	644	**—**	—	**—**	—	**5,897**	644
Additions to oil and gas properties	**172,114**	72,246	**72,444**	72,183	**—**	—	**244,558**	144,429
Property acquisitions	**267**	25	**—**	—	**—**	—	**267**	25
Proceeds from dispositions	**(41)**	(246)	**—**	—	**—**	—	**(41)**	(246)

	June 30, 2022	December 31, 2021
Canadian assets	**$ 2,583,110**	$ 2,658,281
U.S. assets	**2,194,171**	2,152,323
Corporate assets	**32,869**	24,039
Total consolidated assets	**$ 4,810,150**	$ 4,834,643

4. EXPLORATION AND EVALUATION ASSETS

		June 30, 2022		December 31, 2021
Balance, beginning of period	**$**	**172,824**	$	191,865
Capital expenditures		**5,897**		3,298
Property acquisitions		**—**		1,100
Divestitures		**(55)**		(166)
Property swaps		**—**		408
Exploration and evaluation expense		**(10,780)**		(15,212)
Transfer to oil and gas properties (note 5)		**(5,461)**		(7,727)
Foreign currency translation		**1,386**		(742)
Balance, end of period	**$**	**163,811**	$	172,824

At June 30, 2022 and December 31, 2021, there were no indicators of impairment or impairment reversal for exploration and evaluation assets in any of the Company's cash generating units ("CGU").

5. OIL AND GAS PROPERTIES

		Cost		Accumulated depletion		Net book value
Balance, December 31, 2020	**$**	**11,423,676**	**$**	**(8,346,128)**	**$**	**3,077,548**
Capital expenditures		310,005		—		310,005
Property acquisitions		274		—		274
Transfers from exploration and evaluation assets (note 4)		7,727		—		7,727
Change in asset retirement obligations (note 8)		(12,222)		—		(12,222)
Divestitures		(37,835)		32,844		(4,991)
Property swaps		(26,131)		25,900		(231)
Impairment reversal		—		1,542,414		1,542,414
Foreign currency translation		(31,977)		34,765		2,788
Depletion		—		(458,941)		(458,941)
Balance, December 31, 2021	**$**	**11,633,517**	**$**	**(7,169,146)**	**$**	**4,464,371**
Capital expenditures		244,558		—		244,558
Property acquisitions		355		—		355
Transfers from exploration and evaluation assets (note 4)		5,461		—		5,461
Change in asset retirement obligations (note 8)		(181,026)		—		(181,026)
Foreign currency translation		72,623		(39,000)		33,623
Depletion		—		(280,255)		(280,255)
Balance, June 30, 2022	**$**	**11,775,488**	**$**	**(7,488,401)**	**$**	**4,287,087**

At June 30, 2022, there were no indicators of impairment or impairment reversal for oil and gas properties in any of the Company's CGUs.

2021 Impairment Reversals

At June 30, 2021, we identified indicators of impairment reversal for oil and gas properties in each of our six CGUs due to the increase in forecasted commodity prices. The recoverable amount for each of our six CGUs exceeded their carrying amounts which resulted in an impairment reversal of $1.1 billion recorded at June 30, 2021. The recoverable amount for each CGU was based on its FVLCD which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2020 which was adjusted by management for operations between December 31, 2020 and June 30, 2021. The after-tax discount rates applied to the cash flows were between 10% and 16%.

At December 31, 2021, we identified indicators of impairment reversal for oil and gas properties in five CGUs due to the increase in forecasted commodity prices in addition to changes in proved plus probable reserves. The recoverable amount for three CGUs exceeded their carrying amounts which resulted in an impairment reversal of $416 million recorded at December 31, 2021. The recoverable amount for each CGU was based on its fair value less costs of disposal ("FVLCD") which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2021. The after-tax discount rates applied to the cash flows were between 12% and 19%.

6. CREDIT FACILITIES

	June 30, 2022	December 31, 2021
Credit facilities - U.S. dollar denominated (1)	$ 215,423	$ 156,332
Credit facilities - Canadian dollar denominated	281,494	350,182
Credit facilities - principal (2)	496,917	506,514
Unamortized debt issuance costs	(2,507)	(1,343)
Credit facilities	$ 494,410	$ 505,171

(1) U.S. dollar denominated credit facilities balance was US$167.4 million as at June 30, 2022 (December 31, 2021 - US$123.5 million).
(2) The decrease in the principal amount of the credit facilities outstanding from December 31, 2021 to June 30, 2022 is the result of net repayments of $15.3 million, partially offset by an increase in the reported amount of U.S. denominated debt of $5.7 million due to foreign exchange.

At June 30, 2022, Baytex had US$850 million of revolving credit facilities (the "Credit Facilities"). On April 1, 2022, Baytex amended its Credit Facilities to increase total capacity to a US$850 million revolving facility and extended the maturity from April 1, 2024 to April 1, 2026. The Credit Facilities are comprised of a US$50 million operating loan and a US$600 million syndicated revolving loan for Baytex and a US$10 million operating loan and a US$190 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. There were no changes to the financial covenants as a result of the amendment.

The Credit Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. There are no mandatory principal payments required prior to maturity which could be extended upon our request. Advances (including letters of credit) under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank’s prime lending rate, bankers’ acceptance discount rates or secured overnight financing rates ("SOFR"), plus applicable margins.

The weighted average interest rate on the Credit Facilities was 2.6% for the six months ended June 30, 2022 (2.1% for six months ended June 30, 2021).

At June 30, 2022, Baytex had $15.1 million of outstanding letters of credit (December 31, 2021 - $15.0 million) under the Credit Facilities.

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at June 30, 2022.

Covenant Description	Postion as at June 30, 2022	Covenant
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	0.5:1.0	3.5:1.0
Interest Coverage (3) (Minimum Ratio)	13.3:1.0	2.0:1.0

(1) "Senior Secured Debt" is calculated in accordance with the Credit Facility agreements and is defined as the principal amount of the Credit Facilities and other secured obligations identified in the credit agreement. As at June 30, 2022, the Company's Senior Secured Debt totaled $512.1 million which included $496.9 million of principal amounts outstanding and $15.1 million of letters of credit.
(2) "Bank EBITDA" is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, non-recurring losses, certain specific unrealized and non-cash transactions and is calculated based on a trailing twelve-month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended June 30, 2022 was $1.1 billion.
(3) "Interest coverage" is calculated in accordance with the credit agreement and is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding certain non-cash transactions, and is calculated on a trailing twelve-month basis. Financing and interest expense for the twelve months ended June 30, 2022 was $84.8 million.

7. LONG-TERM NOTES

	June 30, 2022	December 31, 2021
5.625% notes (US$200,000 – principal) due June 1, 2024	$ —	$ 253,120
8.75% notes (US$500,000 – principal) due April 1, 2027	**643,600**	632,800
Total long-term notes - principal [(1)]	**643,600**	885,920
Unamortized debt issuance costs	**(8,842)**	(11,393)
Total long-term notes - net of unamortized debt issuance costs	**$ 634,758**	$ 874,527

(1) The decrease in the principal amount of long-term notes outstanding from December 31, 2021 to June 30, 2022 is the result of principal repayments of $252.8 million partially offset by changes in the reported amount of U.S. denominated debt of $10.5 million.

The long-term notes do not contain any significant financial maintenance covenants but do contain a debt incurrence covenant that restricts the Company's ability to raise additional debt beyond the existing Credit Facilities and long-term notes.

On June 1, 2022, Baytex completed the early redemption of the US$200.0 million principal amount of the 5.625% Notes due in 2024 at par plus accrued interest and recorded a decrease to unamortized debt issuance costs of $1.7 million.

8. ASSET RETIREMENT OBLIGATIONS

	June 30, 2022	December 31, 2021
Balance, beginning of period	**$ 743,683**	$ 760,383
Liabilities incurred	**10,905**	14,845
Liabilities settled	**(6,009)**	(6,662)
Liabilities acquired from property acquisitions	**138**	249
Liabilities divested	**(505)**	(3,161)
Property swaps	**—**	(4,113)
Accretion (note 14)	**6,991**	12,381
Government grants [(1)]	**(1,465)**	(2,857)
Change in estimate	**961**	(9,686)
Changes in discount rates and inflation rates [(2)]	**(192,892)**	(17,381)
Foreign currency translation	**353**	(315)
Balance, end of period	**$ 562,160**	$ 743,683
Less current portion of asset retirement obligations	**10,929**	11,080
Non-current portion of asset retirement obligations	**$ 551,231**	$ 732,603

(1) During the six months ended June 30, 2022, Baytex recognized $1.5 million of non-cash other income and a reduction in asset retirement obligations related to government grants provided by the Government of Alberta and the Government of Saskatchewan ($2.9 million for the year ended December 31, 2021).

(2) The discount and inflation rates at June 30, 2022 were 3.1% and 1.8%, respectively, compared to 1.7% and 1.8% at December 31, 2021.

9. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. At June 30, 2022, no preferred shares have been issued by the Company and all common shares issued were fully paid.

The holders of common shares may receive dividends as declared from time to time and are entitled to one vote per share at any meeting of the holders of common shares. All common shares rank equally with regard to the Company's net assets in the event the Company is wound-up or terminated.

During the three months ended June 30, 2022, the Toronto Stock Exchange ("TSX") accepted Baytex's notice of intention to implement a normal course issuer bid ("NCIB"). Under the terms of the NCIB, the Company may purchase for cancellation up to 56.3 million common shares over the 12-month period commencing May 9, 2022. The number of shares authorized for repurchase represents 10% of the Company's public float as at April 29, 2022. Purchases are made on the open market through facilities of the TSX and/or alternative trading systems in Canada and at market prices prevailing at the time of the transaction.

	Number of Common Shares (000s)		Amount
Balance, December 31, 2020	**561,227**	**$**	**5,729,418**
Vesting of share awards	2,986		7,175
Balance, December 31, 2021	**564,213**	**$**	**5,736,593**
Vesting of share awards	5,001		8,429
Common shares repurchased and cancelled	(9,075)		(91,139)
Balance, June 30, 2022	**560,139**	**$**	**5,653,883**

During the six months ended June 30, 2022, Baytex repurchased and cancelled 9.1 million common shares at an average price of $6.88 per share for total consideration of $62.5 million. The total consideration paid includes commissions and fees and is recorded as a reduction to Shareholders' Equity.

10. SHARE-BASED COMPENSATION PLAN

For the three and six months ended June 30, 2022 the Company recorded total compensation expense related to the share awards of $2.9 million and $6.9 million respectively ($2.8 million and $5.8 million for the three and six months ended June 30, 2021). Included in compensation expense related to share awards for the three and six months ended June 30, 2022 is $2.6 million and $4.8 million of cash compensation expense related to the incentive award plan, deferred share unit plan and the associated equity total return swaps ($1.1 million and $2.6 million for the three and six months ended June 30, 2021).

Share Award Incentive Plan

Baytex has a share award plan pursuant to which it issues restricted and performance awards. A restricted award entitles the holder of each award to receive one common share of Baytex at the time of vesting. A performance award entitles the holder of each award to receive between zero and two common shares on vesting; the number of common shares issued is determined by a multiplier. The multiplier, which ranges between zero and two, is calculated based on a number of factors determined and approved by the Board of Directors on an annual basis. The restricted awards and performance awards vest in equal tranches on the first, second and third anniversaries of the grant date. At Baytex's option, these awards may be cash settled at vesting.

The weighted average fair value of share awards granted during the six months ended June 30, 2022 was $5.68 per restricted and performance award ($1.29 for the six months ended June 30, 2021).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards	Total number of share awards
Balance, December 31, 2020	**4,122**	**4,088**	**8,210**
Granted	—	4,067	4,067
Added by performance factor	—	669	669
Vested	(1,861)	(1,152)	(3,013)
Forfeited	(168)	(291)	(459)
Balance, December 31, 2021	**2,093**	**7,381**	**9,474**
Granted	—	1,111	1,111
Vested	(1,359)	(3,614)	(4,973)
Forfeited	(21)	(26)	(47)
Balance, June 30, 2022	**713**	**4,852**	**5,565**

Incentive Award Plan

Baytex has an incentive award plan (the "Incentive Award" plan) whereby the holder of each incentive award is entitled to receive a cash payment equal to the value of one Baytex common share at the time of vesting. The incentive awards vest in equal tranches on the first, second and third anniversaries of the grant date. The cumulative expense is recognized at fair value at each period end and is included in trade and other payables.

During the six months ended June 30, 2022, Baytex granted 1.3 million awards under the Incentive Award plan at a fair value of $5.68 per award (4.9 million awards at $1.29 per award for the six months ended June 30, 2021). At June 30, 2022 there were 5.3 million awards outstanding under the Incentive Award plan (6.4 million awards outstanding at December 31, 2021).

Deferred Share Unit Plan

Baytex has a deferred share unit plan (the "DSU" plan) whereby each Director of Baytex is entitled to receive a cash payment equal to the value of one Baytex common share on the date on which they cease to be a member of the Board. The awards vest immediately upon being granted and are expensed in full on the grant date. The units are recognized at fair value at each period end and are included in trade and other payables.

During the six months ended June 30, 2022, Baytex granted 0.2 million awards under the DSU plan at a fair value of $5.68 per award (0.9 million awards at $1.29 per award for the six months ended June 30, 2021). At June 30, 2022, there were 1.0 million awards outstanding under the DSU plan.

Equity Total Return Swaps

The Company uses equity total return swaps on the equivalent number of Baytex common shares in order to fix a portion of the aggregate cost of the cash-settled plans including the Incentive Award plan, the DSU plan and the Share Award Incentive Plan, at the fair value determined on the grant date. The carrying value of the Company's financial derivatives includes the fair value of the equity total return swap which was an asset of $7.8 million on June 30, 2022 (December 31, 2021 - asset of $6.5 million). At June 30, 2022, an asset of $7.4 million associated with the equity return swap is included in accounts payable as it relates to the settlement of cash compensation payable (December 31, 2021 - an asset of $10.7 million).

11. NET INCOME PER SHARE

Baytex calculates basic income or loss per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted to common shares. The treasury stock method is used to determine the dilutive effect of share awards whereby the potential conversion of share awards and the amount of compensation expense, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the period.

	Three Months Ended June 30					
	2022			2021		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	Net income	Weighted average common shares (000s)	Net income per share
Net income - basic	**$ 180,972**	**566,997**	**$ 0.32**	$ 1,052,999	564,156	$ 1.87
Dilutive effect of share awards	**—**	**4,700**	**—**	—	5,775	—
Net income - diluted	**$ 180,972**	**571,697**	**$ 0.32**	$ 1,052,999	569,931	$ 1.85

For the three and six months ended June 30, 2022 and June 30, 2021 no share awards were excluded from the calculation of diluted income per share as their effect was dilutive.

12. PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas sales from contracts with customers for the Company's Canadian and U.S. operating segments is set forth in the following table.

	Three Months Ended June 30					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 192,986**	**$ 222,606**	**$ 415,592**	$ 106,269	$ 158,390	$ 264,659
Heavy oil	**346,101**	**—**	**346,101**	129,782	—	129,782
NGL	**8,288**	**24,895**	**33,183**	3,786	16,796	20,582
Natural gas sales	**33,822**	**25,471**	**59,293**	14,189	13,142	27,331
Total petroleum and natural gas sales	**$ 581,197**	**$ 272,972**	**$ 854,169**	$ 254,026	$ 188,328	$ 442,354

	Six Months Ended June 30					
	2022			2021		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 373,141**	**$ 403,426**	**$ 776,567**	$ 217,814	$ 263,986	$ 481,800
Heavy oil	**590,539**	**—**	**590,539**	238,820	—	238,820
NGL	**15,772**	**46,902**	**62,674**	8,150	29,939	38,089
Natural gas sales	**55,449**	**42,765**	**98,214**	28,664	39,683	68,347
Total petroleum and natural gas sales	**$ 1,034,901**	**$ 493,093**	**$ 1,527,994**	$ 493,448	$ 333,608	$ 827,056

Included in accounts receivable at June 30, 2022 is $298.9 million of accrued production revenue related to delivered volumes (December 31, 2021 - $154.0 million).

13. INCOME TAXES

The provision for income taxes has been computed as follows:

	Six Months Ended June 30	
	2022	2021
Net income before income taxes	**$ 212,468**	$ 1,079,770
Expected income taxes at the statutory rate of 25.12% (2021 – 24.89%)	**53,372**	268,755
(Increase) decrease in income tax recovery resulting from:		
Effect of foreign exchange	**984**	(656)
Effect of rate adjustments for foreign jurisdictions	**(18,357)**	(17,339)
Effect of change in deferred tax benefit not recognized	**(17,823)**	(191,235)
Effect of internal debt restructuring	**(45,182)**	—
Adjustments, assessments and other	**1,644**	2,598
Income tax (recovery) expense	**$ (25,362)**	$ 62,123

At June 30, 2022, a deferred tax asset of $127.8 million remains unrecognized due to uncertainty surrounding future commodity prices and future capital gains (December 31, 2021 - $145.6 million).

As disclosed in the 2021 annual financial statements, in June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the “CRA”) that denied $591.0 million of non-capital loss deductions that relate to the calculation of income taxes for the years 2011 through 2015. In September 2016, Baytex filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to the Company's file in July 2018. Baytex remains confident that the original tax filings are correct and intends to defend those tax filings through the appeals process.

14. FINANCING AND INTEREST

	Three Months Ended June 30		Six Months Ended June 30	
	2022	2021	**2022**	2021
Interest on credit facilities	**$ 4,070**	$ 3,250	**$ 7,109**	$ 6,586
Interest on long-term notes	**16,356**	20,246	**33,700**	41,253
Interest on lease obligations	**48**	58	**92**	118
Cash Interest	**$ 20,474**	$ 23,554	**$ 40,901**	$ 47,957
Amortization of debt issue costs	**2,734**	790	**3,429**	1,539
Accretion on asset retirement obligations (note 8)	**3,869**	3,367	**6,991**	5,665
Gain on redemption of long-term notes (note 7)	**—**	(357)	**—**	(357)
Financing and interest	**$ 27,077**	$ 27,354	**$ 51,321**	$ 54,804

15. FOREIGN EXCHANGE

	Three Months Ended June 30		Six Months Ended June 30	
	2022	2021	**2022**	2021
Unrealized foreign exchange loss (gain) - intercompany notes (1)	**$ —**	$ 12,579	**$ (2,674)**	$ 26,320
Unrealized foreign exchange loss (gain) - long-term notes & credit facilities	**27,499**	(14,371)	**15,625**	(30,642)
Realized foreign exchange loss (gain)	**210**	(464)	**413**	(739)
Foreign exchange loss (gain)	**$ 27,709**	$ (2,256)	**$ 13,364**	$ (5,061)

(1) Baytex had a series of intercompany notes totaling US$601.0 million outstanding at December 31, 2021 that were issued from a Canadian functional currency subsidiary to a U.S. functional currency subsidiary. These notes are eliminated upon consolidation within the Statement of Financial Position and are revalued at the relevant foreign exchange rate at each period end. Foreign exchange gains or losses incurred within the Canadian functional currency subsidiary are recognized in unrealized foreign exchange gain or loss whereas those within the U.S. functional currency subsidiary are recognized in other comprehensive income. In January 2022 the intercompany notes were transferred from the Canadian functional currency subsidiary to another U.S. functional currency subsidiary. As a result, foreign exchange gains and losses incurred on these notes after the transfer are recognized in other comprehensive income.

16. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, Credit Facilities, and long-term notes. The fair value of trade and other receivables and trade and other payables approximates carrying value due to the short term to maturity. The fair value of the Credit Facilities is equal to the principal amount outstanding as the Credit Facilities bear interest at floating rates and credit spreads that are indicative of market rates. The fair value of the long-term notes is determined based on market prices.

The carrying value and fair value of the Company's financial instruments carried on the condensed consolidated statements of financial position are classified into the following categories:

	June 30, 2022		December 31, 2021		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial derivatives	**$ 17,979**	**$ 17,979**	$ 8,654	$ 8,654	Level 2
Total	**$ 17,979**	**$ 17,979**	$ 8,654	$ 8,654	
Amortized cost					
Trade and other receivables	**$ 326,383**	**$ 326,383**	$ 173,409	$ 173,409	—
Total	**$ 326,383**	**$ 326,383**	$ 173,409	$ 173,409	
Financial Liabilities					
FVTPL					
Financial derivatives	**$ (240,838)**	**$ (240,838)**	$ (134,020)	$ (134,020)	Level 2
Total	**$ (240,838)**	**$ (240,838)**	$ (134,020)	$ (134,020)	
Amortized cost					
Trade and other payables	**$ (309,163)**	**$ (309,163)**	$ (190,692)	$ (190,692)	—
Credit facilities	**(494,410)**	**(496,917)**	(505,171)	(506,514)	—
Long-term notes	**(634,758)**	**(695,853)**	(874,527)	(917,889)	Level 1
Total	**$ (1,438,331)**	**$ (1,501,933)**	$ (1,570,390)	$ (1,615,095)	

There were no transfers between Level 1 and Level 2 during the six months ended June 30, 2022 and 2021.

Foreign Currency Risk

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities recorded in entities with a Canadian dollar functional currency at the reporting date are as follows:

	Assets		Liabilities	
	June 30, 2022	December 31, 2021	**June 30, 2022**	December 31, 2021
U.S. dollar denominated	**US$7,931**	US$602,503	**US$724,501**	US$829,934

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of July 27, 2022:

	Remaining Period	Volume	Price/Unit[1]	Index
Oil				
Basis Swap	Jul 2022 to Dec 2022	12,000 bbl/d	WTI less US$12.40/bbl	WCS
Basis Swap	Jul 2022 to Dec 2022	6,750 bbl/d	WTI less US$3.73/bbl	MSW
Fixed Sell	Jul 2022 to Dec 2022	10,000 bbl/d	US$53.50/bbl	WTI
3-way option[2]	Jul 2022 to Dec 2022	1,500 bbl/d	US$40.00/US$50.00/US$58.10	WTI
3-way option[2]	Jul 2022 to Dec 2022	2,000 bbl/d	US$46.00/US$56.00/US$66.72	WTI
3-way option[2]	Jul 2022 to Dec 2022	2,500 bbl/d	US$47.00/US$57.00/US$67.00	WTI
3-way option[2]	Jul 2022 to Dec 2022	2,500 bbl/d	US$50.00/US$60.00/US$70.00	WTI
3-way option[2]	Jul 2022 to Dec 2022	2,000 bbl/d	US$53.00/US$63.50/US$72.90	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,000 bbl/d	US$55.00/US$66.00/US$84.00	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$60.00/US$75.00/US$91.54	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$100.00	WTI
3-way option[2]	Jan 2023 to Dec 2023	2,500 bbl/d	US$65.00/US$85.00/US$106.50	WTI
Natural Gas				
Fixed Sell	Jul 2022 to Dec 2022	5,000 GJ/d	$2.53/GJ	AECO 7A
Fixed Sell	Jul 2022 to Dec 2022	14,250 GJ/d	$2.84/GJ	AECO 5A
Fixed Sell	Jul 2022 to Dec 2022	1,000 mmbtu/d	US$2.94/mmbtu	NYMEX
3-way option[2]	Jul 2022 to Dec 2022	2,500 mmbtu/d	US$2.25/US$2.75/US$3.06	NYMEX
3-way option[2]	Jul 2022 to Dec 2022	1,500 mmbtu/d	US$2.60/US$2.91/US$3.56	NYMEX
3-way option[2]	Jul 2022 to Dec 2022	2,500 mmbtu/d	US$2.60/US$3.00/US$3.83	NYMEX
3-way option[2]	Jul 2022 to Dec 2022	2,500 mmbtu/d	US$2.65/US$2.90/US$3.40	NYMEX
3-way option[2]	Jul 2022 to Dec 2022	2,500 mmbtu/d	US$3.00/US$3.75/US$4.40	NYMEX

(1) Based on the weighted average price per unit for the period.

(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$50.00/US$60.00/US$70.00 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$60.00/bbl when WTI is between US$50.00/bbl and US$60.00/bbl; Baytex receives the market price when WTI is between US$60.00/bbl and US$70.00/bbl; and Baytex receives US$70.00/bbl when WTI is above US$70.00/bbl.

The following table sets forth the realized and unrealized gains and losses recorded on financial derivatives.

	Three Months Ended June 30		Six Months Ended June 30	
	2022	2021	**2022**	2021
Realized financial derivatives loss	**$ 124,042**	$ 39,024	**$ 208,408**	$ 59,792
Unrealized financial derivatives (gain) loss	**(58,768)**	84,483	**97,493**	170,467
Financial derivatives loss	**$ 65,274**	$ 123,507	**$ 305,901**	$ 230,259

17. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain financial flexibility and sufficient sources of liquidity to execute its capital programs, while meeting short and long-term commitments. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At June 30, 2022, the Company's capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables and the Credit Facilities.

In order to manage its capital structure and liquidity, Baytex may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

The capital intensive nature of Baytex's operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Baytex's capital resources consist primarily of Adjusted Funds Flow, available Credit Facilities and proceeds received from the divestiture of oil and gas properties. The following capital management measures and ratios are used to monitor current and projected sources of liquidity.

Net Debt

The Company uses net debt to monitor it's current financial position and to evaluate existing sources of liquidity. Baytex also uses net debt projections to estimate future liquidity and whether additional sources of capital are required to fund ongoing operations. Baytex also uses a net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis to monitor our existing capital structure and future liquidity requirements.

The following table reconciles Net Debt to amounts disclosed in the primary financial statements.

	June 30, 2022	December 31, 2021
Credit facilities	$ 494,410	$ 505,171
Unamortized debt issuance costs - Credit facilities (note 6)	2,507	1,343
Long-term notes	634,758	874,527
Unamortized debt issuance costs - Long-term notes (note 7)	8,842	11,393
Trade and other payables	309,163	190,692
Trade and other receivables	(326,383)	(173,409)
Net Debt	$ 1,123,297	$ 1,409,717
Net Debt to Adjusted Funds Flow	1.1	1.9

Adjusted Funds Flow

Adjusted funds flow is used to monitor operating performance and the 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 retirements obligations settled during the applicable period.

Adjusted Funds Flow is reconciled to amounts disclosed in the primary financial statements in the following table.

	Three Months Ended June 30		Six Months Ended June 30	
	2022	2021	2022	2021
Cash flows from operating activities	$ 360,034	$ 171,876	$ 559,008	$ 292,856
Change in non-cash working capital	(17,046)	3,014	60,294	37,199
Asset retirement obligations settled	2,716	993	6,009	2,410
Adjusted Funds Flow	$ 345,704	$ 175,883	$ 625,311	$ 332,465

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
COSO	Committee of Sponsoring Organizations of the Treadway Commission
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LLS	Louisiana Light Sweet
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

* *Oil equivalent amounts may be misleading, particularly if used in isolation. In accordance with NI 51-101, a boe conversion ratio for natural gas of 6 Mcf: 1 bbl has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.*

CORPORATE INFORMATION

BOARD OF DIRECTORS

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Chairman of the Board

Edward D. LaFehr
Director

Trudy M. Curran [2,4]
Director

Don G. Hrap [1,3]
Director

Jennifer A. Maki [1,2]
Director

Gregory K. Melchin [1,4]
Director

David L. Pearce [2,3]
Director

Steve D.L. Reynish [3,4]
Director

(1) Member of the Audit Committee
(2) Member of the Human Resources and Compensation Committee
(3) Member of the Reserves and Sustainability Committee
(4) Member of the Nominating and Governance Committee

OFFICERS

Edward D. LaFehr
President and
Chief Executive Officer

Rodney D. Gray
Executive Vice President
and Chief Financial Officer

Chad E. Lundberg
Chief Operating and
Sustainability Officer

Kendall D. Arthur
Vice President, Heavy Oil

Brian G. Ector
Vice President, Capital Markets

Nicole M. Frechette
Vice President, Light Oil

Chad L. Kalmakoff
Vice President, Finance

Scott Lovett
Vice President,
Corporate Development

James R. Maclean
Vice President, General Counsel
and Corporate Secretary

AUDITORS

KPMG LLP

RESERVES ENGINEERS

McDaniel & Associates Consultants Ltd.

TRANSFER AGENT

Odyssey Trust Company

EXCHANGE LISTINGS

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Design: ARTHUR / HUNTER

Printing: Merrill Corporation