BAYTEX

BAYTEX ANNOUNCES SECOND QUARTER 2021 FINANCIAL AND OPERATING RESULTS, FREE CASH FLOW OF $112 MILLION AND REPURCHASE OF LONG-TERM NOTES

CALGARY, ALBERTA (July 28, 2021) - Baytex Energy Corp. ("Baytex")(TSX: BTE) reports its operating and financial results for the three and six months ended June 30, 2021 (all amounts are in Canadian dollars unless otherwise noted).

"During the second quarter, we delivered strong operating results and substantial free cash flow. Our free cash flow profile continues to improve resulting in accelerated debt reduction. We are taking proactive measures to reduce our net debt with the repurchase and cancellation of US$106 million of our outstanding long-term notes due 2024 during and subsequent to the quarter. At current commodity prices, we now expect to generate over $350 million of free cash flow in 2021. In addition, we are drilling our fourth follow up well as we continue to advance our exciting, new, oil discovery in the Clearwater play in Peace River," commented Ed LaFehr, President and Chief Executive Officer.

Q2 2021 Highlights

- Generated production of 81,162 boe/d (81% oil and NGL), a 3% increase over Q1/2021.
- Delivered adjusted funds flow of $176 million ($0.31 per basic share), a 12% increase compared to $157 million ($0.28 per basic share) in Q1/2021.
- Generated free cash flow of $112 million ($0.20 per basic share).
- Realized an operating netback of $33.92/boe, up from $29.80/boe in Q1/2021.
- Repurchased and cancelled US$5.8 million principal amount of 5.625% long-term notes. Subsequent to quarter-end, repurchased and cancelled an additional US$100 million principal amount of 5.625% long-term notes.
- Reduced net debt by $129 million through a combination of free cash flow and the Canadian dollar strengthening relative to the U.S. dollar.

2021 Outlook

As a result of our strong operating performance through the first half of 2021, we are increasing our production guidance to 79,000 to 80,000 boe/d, up from 77,000 to 79,000 boe/d, previously. We continue to forecast 2021 exploration and development expenditures of $285 to $315 million. Our free cash flow profile continues to improve as we benefit from our diversified oil weighted portfolio and our commitment to allocate capital effectively. At current commodity prices, we now expect to deliver over $350 million ($0.62 per basic share) of free cash flow this year, which will accelerate our debt reduction efforts.

Five-Year Outlook

Our five-year outlook (2021 to 2025) highlights our financial and operational sustainability and meaningful free cash flow generation. Through this plan period, we are committed to a disciplined and returns based capital allocation philosophy.

We have updated year one of our five-year outlook (2021) to reflect year-to-date commodity prices and the forward strip for the balance of the year. The remaining years (2022 to 2025) continue to be based on a constant US$55/bbl WTI price. Under the plan, we expect to generate over $1 billion of cumulative free cash flow as we target capital expenditures at less than 70% of our adjusted funds flow, while optimizing production in the 80,000 to 85,000 boe/d range. Under constant US$60/bbl and $65/bbl WTI pricing scenarios, we expect to generate in excess of $1.5 billion and $2.0 billion of cumulative free cash flow, respectively.

Based on the strong pricing environment and free cash flow forecast for 2021, we have accelerated our debt repayment strategy by approximately one year over the base plan presented last quarter. We now anticipate hitting our net debt target of $1.0 to $1.2 billion in 2023 at US$55/bbl. Throughout the plan period we will continue to monitor our leverage position and assess market conditions to determine the best methods or combination thereof to enhance shareholder returns. These could include share buy-backs, a dividend and/or reinvestment for organic growth.

	Three Months Ended			Six Months Ended	
	June 30, 2021	March 31, 2021	June 30, 2020	**June 30, 2021**	June 30, 2020
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 442,354**	$ 384,702	$ 152,689	**$ 827,056**	$ 489,303
Adjusted funds flow [(1)]	**175,883**	156,582	17,887	**332,465**	150,822
Per share - basic	**0.31**	0.28	0.03	**0.59**	0.27
Per share - diluted	**0.31**	0.28	0.03	**0.59**	0.27
Net income (loss)	**1,052,999**	(35,352)	(138,463)	**1,017,647**	(2,636,680)
Per share - basic	**1.87**	(0.06)	(0.25)	**1.81**	(4.71)
Per share - diluted	**1.85**	(0.06)	(0.25)	**1.79**	(4.71)
Capital Expenditures					
Exploration and development expenditures [(1)]	**$ 61,485**	$ 83,588	$ 9,852	**$ 145,073**	$ 186,629
Acquisitions, net of divestitures	**(18)**	(203)	(11)	**(221)**	(51)
Total oil and natural gas capital expenditures	**$ 61,467**	$ 83,385	$ 9,841	**$ 144,852**	$ 186,578
Net Debt					
Credit facilities [(2)]	**$ 486,623**	$ 606,637	$ 704,135	**$ 486,623**	$ 704,135
Long-term notes [(2)]	**1,109,211**	1,131,480	1,225,395	**1,109,211**	1,225,395
Long-term debt	**1,595,834**	1,738,117	1,929,530	**1,595,834**	1,929,530
Working capital deficiency	**33,795**	20,777	65,423	**33,795**	65,423
Net debt [(1)]	**$ 1,629,629**	$ 1,758,894	$ 1,994,953	**$ 1,629,629**	$ 1,994,953
Shares Outstanding - basic (thousands)					
Weighted average	**564,156**	562,085	560,512	**563,126**	560,158
End of period	**564,182**	564,111	560,545	**564,182**	560,545
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 66.07**	$ 57.84	$ 27.85	**$ 61.96**	$ 37.01
MEH oil (US$/bbl)	**67.15**	59.36	26.40	**63.26**	37.97
MEH oil differential to WTI (US$/bbl)	**1.08**	1.52	(1.45)	**1.30**	0.96
Edmonton par ($/bbl)	**77.28**	66.58	29.85	**71.93**	40.64
Edmonton par differential to WTI (US$/bbl)	**(3.13)**	(5.27)	(6.31)	**(4.28)**	(7.24)
WCS heavy oil ($/bbl)	**67.03**	57.46	22.70	**62.33**	28.68
WCS differential to WTI (US$/bbl)	**(11.48)**	(12.46)	(11.47)	**(11.98)**	(16.00)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.83**	$ 2.69	$ 1.72	**$ 2.76**	$ 1.83
AECO ($/mcf)	**2.85**	2.93	1.91	**2.89**	2.03
CAD/USD average exchange rate	**1.2279**	1.2663	1.3860	**1.2471**	1.3653

	Three Months Ended			Six Months Ended	
	June 30, 2021	March 31, 2021	June 30, 2020	**June 30, 2021**	June 30, 2020
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**37,134**	35,430	38,951	**36,286**	42,333
Heavy oil (bbl/d)	**21,269**	21,989	11,832	**21,627**	20,343
NGL (bbl/d)	**7,563**	6,238	7,634	**6,904**	7,728
Total liquids (bbl/d)	**65,966**	63,657	58,417	**64,817**	70,404
Natural gas (mcf/d)	**91,172**	90,739	84,546	**90,957**	90,451
Oil equivalent (boe/d @ 6:1) [3]	**81,162**	78,780	72,508	**79,978**	85,479
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense [4]	**$ 422,387**	$ 367,582	$ 147,229	**$ 789,969**	$ 462,486
Royalties	**(81,531)**	(66,950)	(29,156)	**(148,481)**	(85,876)
Operating expense	**(82,901)**	(80,548)	(73,680)	**(163,449)**	(178,150)
Transportation expense	**(7,486)**	(8,788)	(5,031)	**(16,274)**	(15,373)
Operating netback [1]	**$ 250,469**	**$ 211,296**	**$ 39,362**	**$ 461,765**	**$ 183,087**
General and administrative	**(10,610)**	(8,733)	(7,438)	**(19,343)**	(17,213)
Cash financing and interest	**(23,554)**	(24,403)	(27,387)	**(47,957)**	(55,922)
Realized financial derivatives (loss) gain	**(39,024)**	(20,768)	13,624	**(59,792)**	40,474
Other [5]	**(1,398)**	(810)	(274)	**(2,208)**	396
Adjusted funds flow [1]	**$ 175,883**	**$ 156,582**	**$ 17,887**	**$ 332,465**	**$ 150,822**
Netback (per boe)					
Total sales, net of blending and other expense [4]	**$ 57.19**	$ 51.84	$ 22.31	**$ 54.57**	$ 29.73
Royalties	**(11.04)**	(9.44)	(4.42)	**(10.26)**	(5.52)
Operating expense	**(11.22)**	(11.36)	(11.17)	**(11.29)**	(11.45)
Transportation expense	**(1.01)**	(1.24)	(0.76)	**(1.12)**	(0.99)
Operating netback [1]	**$ 33.92**	**$ 29.80**	**$ 5.96**	**$ 31.90**	**$ 11.77**
General and administrative	**(1.44)**	(1.23)	(1.13)	**(1.34)**	(1.11)
Cash financing and interest	**(3.19)**	(3.44)	(4.15)	**(3.31)**	(3.59)
Realized financial derivatives (loss) gain	**(5.28)**	(2.93)	2.06	**(4.13)**	2.60
Other [5]	**(0.20)**	(0.12)	(0.03)	**(0.15)**	0.02
Adjusted funds flow [1]	**$ 23.81**	**$ 22.08**	**$ 2.71**	**$ 22.97**	**$ 9.69**

Notes:

(1) The terms “adjusted funds flow”, “exploration and development expenditures”, “net debt” and “operating netback” do not have any standardized meaning as prescribed by Canadian Generally Accepted Accounting Principles (“GAAP”) and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. See the advisory on non-GAAP measures at the end of this press release.

(2) Principal amount of instruments. The carrying amount of debt issue costs associated with the credit facilities and long-term notes are excluded on the basis that these amounts have been paid by Baytex and do not represent an additional source of capital or repayment obligations.

(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) Realized heavy oil prices are calculated based on sales dollars, net of blending and other expense. We include the cost of blending diluent in our realized heavy oil sales price in order to compare the realized pricing on our produced volumes to the WCS benchmark.

(5) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and share-based compensation. Refer to the Q2/2021 MD&A for further information on these amounts.

Q2/2021 Results

During Q2/2021, we delivered strong operating and financial results as we executed on our plan to maximize free cash flow and reduce debt. During the quarter, we delivered adjusted funds flow of $176 million ($0.31 per basic share). This resulted in substantial quarterly free cash flow of $112 million, which along with the Canadian dollar strengthening relative to the U.S. dollar, contributed to a $129 million reduction in our net debt.

Production during the second quarter averaged 81,162 boe/d (81% oil and NGL), up 3% as compared to 78,780 boe/d (81% oil and NGL) in Q1/2021. The increased production reflects the timing of completion activity in the Eagle Ford and and strong performance across our light and heavy oil assets in Canada. Exploration and development expenditures totaled $61 million in Q2/2021 that included the drilling of 34 (19.7 net) wells with a 100% success rate.

During Q2/2021, we reported net income of $1.1 billion ($1.85 per diluted share). At June 30, 2021, we identified indicators of impairment reversal for our oil and gas properties due to the increase in forecasted commodity prices. As a result, we recorded an impairment reversal of $1.1 billion during the second quarter as the estimated recoverable amounts exceeded the carrying value of our oil and gas properties.

2021 Guidance

In 2021, we are benefiting from our diversified oil weighted portfolio and our commitment to allocate capital effectively. Based on the forward strip[(1)], we expect to generate over $350 million of free cash flow in 2021.

As a result of our strong operating performance through the first half of 2021, we are increasing our production guidance to 79,000 to 80,000 boe/d, up from 77,000 to 79,000 boe/d, previously. We continue to forecast 2021 exploration and development expenditures of $285 to $315 million.

Our interest expense guidance is 3% lower due to reduced net debt and the repurchase and cancellation of US$106 million principal amount of 5.625% long-term notes.

The following table highlights our updated 2021 annual guidance.

	2021 Guidance [(2)]	**2021 Revised Guidance**
Exploration and development expenditures	$285 - $315 million	no change
Production (boe/d)	77,000 - 79,000	79,000 - 80,000
Expenses:		
Royalty rate	18.0% - 18.5%	no change
Operating	$11.25 - $12.00/boe	no change
Transportation	$1.15 - $1.25/boe	no change
General and administrative	$42 million ($1.48/boe)	$42 million ($1.45/boe)
Interest	$98 million ($3.46/boe)	$95 million ($3.27/boe)
Leasing expenditures	$4 million	no change
Asset retirement obligations	$6 million	no change

Operating Results

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 33,957 boe/d (80% oil and NGL) during Q2/2021, as compared to 26,741 boe/d in Q1/2021. The higher volumes reflect an increased pace of completions and continued strong operating performance. During the second quarter we commenced production from 38 (10.2 net) wells, up from 24 (7.0 net) wells in Q1/2021. In Q2/2021, we invested $31 million on exploration and development in the Eagle Ford and generated an operating netback of $112 million. We expect to bring approximately 22 net wells on production in the Eagle Ford in 2021.

Notes:

(1) 2021 full-year pricing assumptions: WTI - US$64/bbl; WCS differential - US$13/bbl; MSW differential – US$4/bbl, NYMEX Gas - US$3.30/mcf; AECO Gas - $3.45/mcf and Exchange Rate (CAD/USD) - 1.26.

(2) As announced on April 29, 2021.

Production in the Viking averaged 16,301 boe/d (88% oil and NGL) during Q2/2021, as compared to 19,403 boe/d in Q1/2021. Our capital program in the second quarter included the seasonal slowdown, which resulted in the completion of 14 (14.0 net) wells, as compared to 44 (43.2 net) wells during the first quarter. In Q2/2021, we invested $17 million on exploration and development in the Viking and generated an operating netback of $72 million. We expect to bring approximately 120 net wells on production in the Viking during 2021.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 23,304 boe/d (91% oil and NGL) during the Q2/2021, as compared to 24,395 boe/d in Q1/2021. We scheduled minimal heavy oil development for the first half of 2021. Our heavy oil program kicked off in June with approximately 35 net wells planned for the year, including up to seven net wells in our Spirit River (Clearwater equivalent) play.

Peace River Clearwater

Across all of our core assets, inventory enhancement continues to be a priority. We are also committed to building and maintaining respectful relationships with Indigenous communities and creating opportunities for meaningful economic participation and inclusion. In early 2020, we executed a strategic agreement with the Peavine Métis settlement in the Peace River area that covers 60 sections of land directly to the south of our existing Seal operations. At the time, we identified significant potential for this early stage exploratory play targeting the Spirit River formation, a Clearwater formation equivalent.

Our appraisal program continues to yield encouraging results and pending continued success, sets the stage for a potential increase in activity in 2022. We plan to drill up to seven net appraisal wells in 2021, of which five net appraisal wells will occur on our Peavine lands. Across our acreage position in northwest Alberta, we estimate that over 100 sections are prospective for Clearwater development. The following table summarizes our Peavine appraisal program for 2021.

Area	Well	Spud	Rig Release	# of Laterals	30-Day Initial Production Rate (bbl/d)
Peavine	100/04-34-078-16W5	January 6	January 19	2	175
Peavine	102/04-34-078-16W5	June 15	June 21	2	175
Peavine	100/13-27-078-16W5	June 22	July 6	8	On Production July 10
Peavine	100/05-34-078-16W5	July 8	July 18	8	On Production July 22
Peavine	100/11-31-078-15W5	July 20		8	

Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 1,698 boe/d (80% oil and NGL) during Q2/2021, as compared to 2,138 boe/d in Q1/2021. We now have nine producing wells in the Pembina area and have significantly de-risked our approximately 38-kilometre long acreage fairway, where we hold 232 sections (100% working interest) of Duvernay land. We expect to bring two additional 100% working interest wells on production during the third quarter.

Financial Liquidity

Our credit facilities total approximately $1.0 billion and have a maturity date of April 2, 2024. These are not borrowing base facilities and do not require annual or semi-annual reviews. As of June 30, 2021, we had $511 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $477 million.

Our net debt, which includes our credit facilities, long-term notes and working capital, totaled $1.63 billion at June 30, 2021, down from $1.76 billion at March 31, 2021.

On May 4, 2021, we repurchased and cancelled US$5.8 million principal amount of 5.625% long-term notes. Subsequent to the quarter, we used free cash flow generated in the first half of 2021 to repurchase and cancel US$100 million principal amount of the 5.625% long-term notes at the call price of 100.938% plus accrued interest effective July 28, 2021.

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 2021, we have entered into hedges on approximately 45% of our net crude oil exposure utilizing a combination of fixed price swaps at US$45/bbl and a 3-way option structure that provides price protection at US$44.71/bbl with upside participation to US$52.42/bbl. We also have WTI-MSW differential hedges on approximately 50% of our expected net Canadian light oil exposure at US$5.03/bbl and WCS differential hedges on approximately 50% of our net expected heavy oil exposure at a WTI-WCS differential of approximately US$13.23/bbl.

For 2022, we have entered into hedges on approximately 42% of our net crude oil exposure utilizing a combination of swaptions at US$53.50/bbl and a 3-way option structure that provides price protection at US$57.76/bbl with upside participation to US$67.51/bbl. We also have WTI-MSW differential hedges on approximately 13% of our expected net Canadian light oil exposure at US$4.63/bbl and WCS differential hedges on approximately 39% of our expected net heavy oil exposure at a WTI-WCS differential of approximately US$12.53/bbl.

A complete listing of our financial derivative contracts can be found in Note 16 to our Q2/2021 financial statements.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 30, 2021 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

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

Baytex will host a conference call tomorrow, July 29, 2021, 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/baytex20210729.html in your web browser.

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

Advisory Regarding Forward-Looking Statements

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

Specifically, this press release contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that we expect to generate over $350 million of free cash flow ($0.62 per basic share) in 2021; that our debt reduction will accelerate; our five-year outlook: including that it demonstrates financial and operational sustainability, meaningful free cash flow generation and that we are committed to disciplined and returns based philosophy for that period, the cumulative free cash flow it will generate at certain WTI oil prices and that we are targeting capital expenditures at less than 70% of adjusted funds flow; we anticipate hitting our debt target of $1.0 to $1.2 billion in 2023 at US$55 WTI; that we will monitor our leverage position and market conditions to enhance shareholder returns which could be share buy-backs, a dividend or reinvestment for organic growth; we expect to benefit from our diversified oil weighted portfolio and our commitment to allocate capital effectively; our updated guidance for 2021 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; in 2021 that we expect to: bring on production 22 net wells in the Eagle Ford and 120 in the Viking and plan to drill 35 net wells in Heavy Oil, including 6 in our Spirit River (Clearwater equivalent); that we are committed to building and maintaining respectful relationships with Indigenous communities and creating opportunities for meaningful economic participation and inclusion; the potential for increased activity in 2022 pending success in Peace River Clearwater; our drilling plans for the Clearwater lands for the remainder of 2021; that we have 100 sections of highly prospective Clearwater lands; that we expect to bring two 100% working Duvernay wells on Production in Q3/2021; and drill 2 net wells in the Duvernay; and that we have de-risked our approximately 38-kilometer acreage fairway in the Pembina Duvernay; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility; the percentage of our net exposure to crude oil, the MTI-MSW differential and WCS differential that we have hedged for H2/2021 and 2022.

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); the availability and cost of capital or borrowing; risks associated with our ability to exploit our properties and add reserves; availability and cost of gathering, processing and pipeline systems; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; costs to develop and operate our properties; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; retaining or replacing *our leadership and key personnel; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; results of litigation; risks associated with large projects; 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, 2020, 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.

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

Non-GAAP Financial and Capital Management Measures

In this news release, we refer to certain financial measures (such as adjusted funds flow, exploration and development expenditures, free cash flow, net debt and operating netback) which do not have any standardized meaning prescribed by Canadian GAAP ("non-GAAP measures") and are considered non-GAAP measures. While adjusted funds flow, exploration and development expenditures, free cash flow, net debt 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.

Adjusted funds flow is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but 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.

In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our cash flow on a continuing basis. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three and six months ended June 30, 2021.

Exploration and development expenditures is not a measurement based on GAAP in Canada. We define exploration and development expenditures as additions to exploration and evaluation assets combined with additions to oil and gas properties. Our definition of exploration and development expenditures may not be comparable to other issuers. We use exploration and development expenditures to measure and evaluate the performance of our capital programs. The total amount of exploration and development expenditures is managed as part of our budgeting process and can vary from period to period depending on the availability of adjusted funds flow and other sources of liquidity.

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as adjusted funds flow less exploration and development expenditures (both non-GAAP measures discussed above), payments on lease obligations, and asset retirement obligations settled. 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.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of cash, trade and other accounts receivable, trade and other accounts payable, and the principal amount of both the long-term notes and the credit facilities. 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.

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 divided by barrels of oil equivalent sales volume for the applicable period. 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.

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

	Three Months Ended June 30, 2021					**Six Months Ended June 30, 2021**				
	Heavy Oil (bbl/d)	**Light and Medium Oil (bbl/d)**	**NGL (bbl/d)**	**Natural Gas (Mcf/d)**	**Oil Equivalent (boe/d)**	**Heavy Oil (bbl/d)**	**Light and Medium Oil (bbl/d)**	**NGL (bbl/d)**	**Natural Gas (Mcf/d)**	**Oil Equivalent (boe/d)**
Canada – Heavy										
Peace River	11,293	7	25	10,722	13,112	11,729	7	25	11,697	13,711
Lloydminster	9,976	5	—	1,268	10,192	9,898	5	—	1,398	10,136
Canada - Light										
Viking	—	14,284	140	11,262	16,301	—	15,866	136	11,044	17,843
Duvernay	—	791	568	2,033	1,698	—	969	612	2,015	1,917
Remaining Properties	—	574	1,046	25,689	5,902	—	587	1,101	25,882	6,002
United States										
Eagle Ford	—	21,473	5,784	40,198	33,957	—	18,852	5,030	38,921	30,369
Total	21,269	37,134	7,563	91,172	81,162	21,627	36,286	6,904	90,957	79,978

Baytex Energy Corp.

Baytex Energy Corp. is an oil and gas corporation based in Calgary, Alberta. The company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. Approximately 81% of Baytex's production is weighted toward crude oil and natural gas liquids. Baytex's common shares trade on the Toronto Stock Exchange under the symbol BTE.

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

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BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three and six months ended June 30, 2021 and 2020
Dated July 28, 2021

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, 2021. This information is provided as of July 28, 2021. 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, 2021 ("Q2/2021" and "YTD 2021") have been compared with the results for the three and six months ended June 30, 2020 ("Q2/2020" and "YTD 2020"). 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, 2021, its audited comparative consolidated financial statements for the years ended December 31, 2020 and 2019, together with the accompanying notes, and its Annual Information Form for the year ended December 31, 2020. 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 prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). The terms "adjusted funds flow", "operating netback", "exploration and development expenditures", "free cash flow", "net debt", and "Bank EBITDA" do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. We refer you to our advisory on forward-looking information and statements and a summary of our non-GAAP 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 for Q2/2021 as the global economy continued to recover from the impact of the COVID-19 pandemic. The outlook for crude oil demand has improved with the increase in economic activity due to the distribution of vaccines and easing of restrictions. Oil prices were also supported by ongoing OPEC production curtailments and limited supply growth from large independent producers. As a result, the average WTI benchmark price for Q2/2021 was US$66.07/bbl which was US$38.22/bbl higher than Q2/2020 when WTI averaged US$27.85/bbl. With higher commodity prices, we generated adjusted funds flow of $175.9 million and free cash flow of $112.5 million which contributed to a $129.3 million reduction in net debt from Q1/2021. Strong well performance across all of our assets resulted in production of 81,162 boe/d which exceeded the high end of our previous annual guidance range of 77,000 - 79,000 boe/d. Our disciplined approach to capital allocation and continued focus on reducing our cost structure has improved the results we have achieved as commodity prices have increased.

Exploration and development expenditures of $61.5 million for Q2/2021 were split between our Canadian and U.S. properties. Our U.S. production increased 7,216 boe/d from Q1/2021 as 38 (10.2 net) wells were brought on production in Q2/2021 compared to 24 (7.0 net) wells in Q1/2021. Due to spring break up, activity levels in Canada were lower in Q2/2021 resulting in 15 (15.0 net) wells brought on production compared to 51 (47.1 net) wells in Q1/2021. Lower activity levels resulted in production in Canada that was 4,834 boe/d lower than Q1/2021.

Adjusted funds flow was $175.9 million in Q2/2021 which is higher than $17.9 million reported for Q2/2020 and $156.6 million for Q1/2021 as a result of higher benchmark prices along with higher production for Q2/2021 relative to Q2/2020 and Q1/2021. The increase in crude oil prices was the primary factor that resulted in a $211.1 million increase in operating netback for Q2/2021 relative to Q2/2020. The increase in commodity prices also resulted in an impairment reversal for our oil and gas properties of $1.1 billion for Q2/2021 which contributed to net income of $1.1 billion compared to a net loss of $0.1 billion for Q2/2020.

Net debt decreased $218.0 million to $1.63 billion at June 30, 2021 compared to $1.85 billion at December 31, 2020. The reduction in net debt was primarily due to free cash flow of $183.0 million being allocated to debt repayment combined with a $35.0 million decrease in the reported amount of our U.S. dollar denominated net debt due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2021.

During Q2/2021, we purchased and cancelled US$5.8 million principal of the 5.625% Notes at a discount and recorded a gain of $0.4 million. Subsequent to Q2/2021 we also used free cash flow generated in the first half of 2021 to repurchase and cancel US$100.0 million principal amount of the 5.625% Notes due 2024 at the call price of 100.938%, plus accrued interest, effective July 28, 2021.

2021 GUIDANCE

The following table compares our revised 2021 annual guidance to our previously announced guidance. As a result of our strong operational performance through the first half of 2021 we are increasing our annual production guidance range to 79,000 - 80,000 boe/d while maintaining exploration and development expenditures guidance of $285 - $315 million.

Our interest expense guidance is 3% lower due to reduced net debt and the repurchase and cancellation of US$105.8 million principal amount of the 5.625% Notes.

	Previous Annual Guidance [1]	Revised Annual Guidance
Exploration and development expenditures	$285 - $315 million	no change
Production (boe/d)	77,000 - 79,000	79,000 - 80,000
Expenses:		
Royalty rate	18.0% - 18.5%	no change
Operating	$11.25 - $12.00/boe	no change
Transportation	$1.15 - $1.25/boe	no change
General and administrative	$42 million ($1.48/boe)	$42 million ($1.45/boe)
Interest	$98 million ($3.46/boe)	$95 million ($3.27/boe)
Leasing expenditures	$4 million	no change
Asset retirement obligations	$6 million	no change

(1) As announced on April 29, 2021.

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					
	2021			2020		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**15,661**	**21,473**	**37,134**	18,762	20,189	38,951
Heavy oil	**21,269**	**—**	**21,269**	11,832	—	11,832
Natural Gas Liquids (NGL)	**1,779**	**5,784**	**7,563**	933	6,701	7,634
Total liquids (bbl/d)	**38,709**	**27,257**	**65,966**	31,527	26,890	58,417
Natural gas (mcf/d)	**50,974**	**40,198**	**91,172**	36,982	47,564	84,546
Total production (boe/d)	**47,205**	**33,957**	**81,162**	37,691	34,817	72,508
Production Mix						
Segment as a percent of total	**58 %**	**42 %**	**100 %**	52 %	48 %	100 %
Light oil and condensate	**33 %**	**63 %**	**46 %**	50 %	58 %	54 %
Heavy oil	**45 %**	**— %**	**26 %**	31 %	— %	16 %
NGL	**4 %**	**17 %**	**9 %**	2 %	19 %	11 %
Natural gas	**18 %**	**20 %**	**19 %**	17 %	23 %	19 %

	Six Months Ended June 30					
	2021			2020		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**17,434**	**18,852**	**36,286**	21,501	20,832	42,333
Heavy oil	**21,627**	**—**	**21,627**	20,343	—	20,343
Natural Gas Liquids (NGL)	**1,874**	**5,030**	**6,904**	1,125	6,603	7,728
Total liquids (bbl/d)	**40,935**	**23,882**	**64,817**	42,969	27,435	70,404
Natural gas (mcf/d)	**52,036**	**38,921**	**90,957**	42,041	48,410	90,451
Total production (boe/d)	**49,609**	**30,369**	**79,978**	49,976	35,503	85,479
Production Mix						
Segment as a percent of total	**62 %**	**38 %**	**100 %**	58 %	42 %	100 %
Light oil and condensate	**35 %**	**62 %**	**45 %**	43 %	59 %	50 %
Heavy oil	**44 %**	**— %**	**27 %**	41 %	— %	24 %
NGL	**4 %**	**17 %**	**9 %**	2 %	19 %	9 %
Natural gas	**17 %**	**21 %**	**19 %**	14 %	22 %	17 %

Production was 81,162 boe/d for Q2/2021 and 79,978 boe/d for YTD 2021 compared to 72,508 boe/d for Q2/2020 and 85,479 boe/d for YTD 2020. Total production was higher in Q2/2021 compared to Q2/2020 after we restored production that was shut-in during Q2/2020 and restarted development activity late in 2020. We have continued our development in Canada and the U.S. during 2021 following the reset of our business in 2020 which, along with strong well performance, resulted in production of 81,162 boe/d for Q2/2021. Total production of 79,978 boe/d for YTD 2021 is at the high end of our revised annual guidance of 79,000 - 80,000 and reflects the strong well performance in the U.S. and Canada YTD.

In Canada, production of 47,205 boe/d for Q2/2021 was higher than Q2/2020 production of 37,691 boe/d as our 2020 production was impacted by the suspension of our capital development program combined with shut-in production due to the sharp decline in oil prices in 2020. We restored shut-in production and restarted development activity as crude oil prices strengthened during the second half of 2020. With continued development activity and strong well performance, production averaged 49,609 boe/d for YTD 2021, consistent with production of 49,976 boe/d for YTD 2020 which reflects a higher level of activity in Q1/2020 before we shut-in production during Q2/2020.

In the U.S., production was 33,957 boe/d for Q2/2021 and 30,369 boe/d for YTD 2021 compared to 34,817 boe/d for Q2/2020 and 35,503 boe/d for YTD 2020. Production was lower in 2021 due to limited development activity during 2020 along with the impact of the Texas storm that disrupted operations in February 2021. We initiated production from 38 (10.2 net) wells during Q2/2021 and 62 (17.2 net) wells during YTD 2021 compared to 17 (4.6 net) wells during Q2/2020 and 47 (10.7 net) wells during YTD 2020.

Commodity Prices

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

Crude Oil

Global benchmark prices for crude oil continued to strengthen during Q2/2021 as the outlook for oil demand improved due to increasing global economic activity while OPEC has maintained production curtailments that have limited supply as economies recover and slowly reopen. These factors resulted in the WTI benchmark price averaging US$66.07/bbl for Q2/2021 and US$61.96/bbl for YTD 2021 which was higher relative to Q2/2020 and YTD 2020 when WTI averaged US$27.85/bbl and US$37.01/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$67.15/bbl during Q2/2021 and US$63.26/bbl during YTD 2021 which is higher than US$26.40/bbl during Q2/2020 and US$37.97/bbl during YTD 2020. The MEH benchmark was at a US$1.08/bbl premium to WTI in Q2/2021 and a US$1.30/bbl premium in YTD 2021 compared to a US$1.45/bbl discount to WTI during Q2/2020 and US$0.96/bbl premium during YTD 2020.

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets from Western Canada. Canadian light and heavy oil differentials to WTI were narrower in Q2/2021 and YTD 2021 relative to Q2/2020 and YTD 2020 as a result of stronger demand for Canadian oil production along with lower light and heavy oil supply to North American markets during 2021.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price while pricing for our heavy oil production is based on the WCS benchmark price. The Edmonton par price averaged $77.28/bbl during Q2/2021 and $71.93/bbl during YTD 2021 compared to $29.85/bbl during Q2/2020 and $40.64/bbl during YTD 2020. Edmonton par traded at a discount to WTI of US$3.13/bbl for Q2/2021 and US$4.28/bbl for YTD 2021 compared to a discount of US$6.31/bbl for Q2/2020 and US$7.24/bbl for YTD 2020. The WCS heavy oil price for Q2/2021 and YTD 2021 averaged $67.03/bbl and $62.33/bbl, respectively, compared to $22.70/bbl and $28.68/bbl for the same periods of 2020. The WCS heavy oil differential was US$11.48/bbl in Q2/2021 and US$11.98/bbl in YTD 2021 compared to US$11.47/bbl for Q2/2020 and US$16.00/bbl for YTD 2020.

Natural Gas

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. The NYMEX natural gas benchmark averaged US$2.83/mmbtu for Q2/2021 and US$2.76/mmbtu for YTD 2021 which is higher than US$1.72/mmbtu for Q2/2020 and US$1.83/mmbtu for YTD 2020. Lower U.S. natural gas production and increased demand along with the impact of the Texas winter storm in February 2021 resulted in higher natural gas prices in YTD 2021 relative to YTD 2020.

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 increasing supply and limited market access for Canadian natural gas production. The AECO benchmark averaged $2.85/mcf during Q2/2021 and $2.89/mcf during YTD 2021 which is higher than $1.91/mcf for Q2/2020 and $2.03/mcf for YTD 2020.

The following tables compare select benchmark prices and our average realized selling prices for the three and six months ended June 30, 2021 and 2020.

	Three Months Ended June 30			Six Months Ended June 30		
	2021	2020	Change	**2021**	2020	Change
Benchmark Averages						
WTI oil (US$/bbl) (1)	**66.07**	27.85	38.22	**61.96**	37.01	24.95
MEH oil (US$/bbl) (2)	**67.15**	26.40	40.75	**63.26**	37.97	25.29
MEH oil differential to WTI (US$/bbl)	**1.08**	(1.45)	2.53	**1.30**	0.96	0.34
Edmonton par oil ($/bbl) (3)	**77.28**	29.85	47.43	**71.93**	40.64	31.29
Edmonton par oil differential to WTI (US$/bbl)	**(3.13)**	(6.31)	3.18	**(4.28)**	(7.24)	2.96
WCS heavy oil ($/bbl) (4)	**67.03**	22.70	44.33	**62.33**	28.68	33.65
WCS heavy oil differential to WTI (US$/bbl)	**(11.48)**	(11.47)	(0.01)	**(11.98)**	(16.00)	4.02
AECO natural gas price ($/mcf) (5)	**2.85**	1.91	0.94	**2.89**	2.03	0.86
NYMEX natural gas price (US$/mmbtu) (6)	**2.83**	1.72	1.11	**2.76**	1.83	0.93
CAD/USD average exchange rate	**1.2279**	1.3860	(0.1581)	**1.2471**	1.3653	(0.1182)

(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					
	2021			2020		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)	**$ 74.57**	**$ 81.06**	**$ 78.32**	$ 24.73	$ 33.23	$ 29.14
Heavy oil ($/bbl) (1)	**56.74**	**—**	**56.74**	17.22	—	17.22
NGL ($/bbl)	**23.38**	**31.91**	**29.90**	9.98	13.18	12.79
Natural gas ($/mcf)	**3.05**	**3.59**	**3.29**	1.86	2.38	2.15
Weighted average ($/boe) (1)	**$ 54.49**	**$ 60.95**	**$ 57.19**	$ 19.79	$ 25.05	$ 22.31

	Six Months Ended June 30					
	2021			2020		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)	**$ 69.02**	**$ 77.36**	**$ 73.36**	$ 38.67	$ 48.05	$ 43.29
Heavy oil ($/bbl) (1)	**51.53**	**—**	**51.53**	19.72	—	19.72
NGL ($/bbl)	**24.02**	**32.88**	**30.48**	10.72	14.04	13.56
Natural gas ($/mcf)	**3.04**	**5.63**	**4.15**	1.94	2.50	2.24
Weighted average ($/boe) (1)	**$ 50.82**	**$ 60.69**	**$ 54.57**	$ 26.53	$ 34.22	$ 29.73

(1) Realized heavy oil prices are calculated based on sales volumes and sales dollars, net of blending and other expense.

Average Realized Sales Prices

Our weighted average sales price was $57.19/boe for Q2/2021 and $54.57/boe for YTD 2021 compared to $22.31/boe for Q2/2020 and $29.73/boe for YTD 2020. In Canada, our realized price of $54.49/boe for Q2/2021 was $34.70/boe higher than $19.79/boe for Q2/2020. Our realized price in the U.S. was $60.95/boe in Q2/2021 which is $35.90/boe higher than $25.05/boe in Q2/2020. The increase in our realized price in Canada and the U.S. for Q2/2021 and YTD 2021 was a result of higher North American benchmark prices relative to the same periods of 2020.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price was $74.57/bbl for Q2/2021 and $69.02/bbl for YTD 2021 compared to $24.73/bbl for Q2/2020 and $38.67/bbl for YTD 2020. Our realized light oil and condensate price for Q2/2021 and YTD 2021 increased with the improvement in the benchmark price and represents discounts of $2.71/bbl and $2.91/bbl, respectively, to the Edmonton par price which is in line with expectations. Our realized light oil and condensate price was impacted by certain fixed price physical delivery contracts during Q2/2020 which resulted in a discount to the Edmonton par price of $5.12/bbl for Q2/2020 and $1.97/bbl for YTD 2020.

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 $81.06/bbl for Q2/2021 and $77.36/bbl for YTD 2021 compared to $33.23/bbl for Q2/2020 and $48.05/bbl for YTD 2020. Expressed in U.S. dollars, our realized light oil and condensate price of US$66.02/bbl for Q2/2021 and US$62.03/bbl for YTD 2021 represents discounts to MEH of US$1.13/bbl and US$1.23/bbl, respectively, which are narrower than a discount of US$2.42/bbl for Q2/2020 and US$2.78/bbl for YTD 2020. Narrower discounts to MEH reflects stronger price realizations on our marketing contracts in place during 2021.

Our realized heavy oil price, net of blending and other expense averaged $56.74/bbl in Q2/2021 and $51.53/bbl in YTD 2021 compared to $17.22/bbl in Q2/2020 and $19.72/bbl in YTD 2020. Our realized heavy oil price for Q2/2021 and YTD 2021 was $39.52/bbl and $31.81/bbl higher relative to Q2/2020 and YTD 2020, respectively, which is slightly less than a $44.33/bbl and $33.65/bbl increase in the WCS benchmark price over the same periods as we have certain fixed price delivery contracts that limit our exposure to the changes in WCS pricing.

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 was $29.90/bbl in Q2/2021 or 37% of WTI (expressed in Canadian dollars) compared to $12.79/bbl or 33% of WTI (expressed in Canadian dollars) in Q2/2020. Our realized NGL price was $30.48/bbl in YTD 2021 or 39% of WTI (expressed in Canadian dollars) compared to $13.56/bbl or 27% of WTI (expressed in Canadian dollars) in YTD 2020.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price was $3.05/mcf for Q2/2021 and $3.04/mcf for YTD 2021 compared to $1.86/mcf in Q2/2020 and $1.94/mcf for YTD 2020 and was relatively consistent with the AECO benchmark price in both periods. In the U.S., our realized natural gas price was US$2.92/mcf for Q2/2021 and US$4.51/mcf for YTD 2021 compared to US$1.72/mcf for Q2/2020 and US$1.83/mcf for YTD 2020. A portion of our natural gas production is based on the NYMEX daily index which resulted in a US$1.75/mcf premium to the NYMEX monthly benchmark for YTD 2021 due to the fluctuations in the daily index caused by the winter storm in Texas during February 2021.

Petroleum and Natural Gas Sales

	Three Months Ended June 30					
	2021			2020		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 106,269**	**$ 158,390**	**$ 264,659**	$ 42,231	$ 61,043	$ 103,274
Heavy oil	**129,782**	**—**	**129,782**	24,003	—	24,003
NGL	**3,786**	**16,796**	**20,582**	847	8,035	8,882
Total oil sales	**239,837**	**175,186**	**415,023**	67,081	69,078	136,159
Natural gas sales	**14,189**	**13,142**	**27,331**	6,244	10,286	16,530
Total petroleum and natural gas sales	**254,026**	**188,328**	**442,354**	73,325	79,364	152,689
Blending and other expense	**(19,967)**	**—**	**(19,967)**	(5,460)	—	(5,460)
Total sales, net of blending and other expense	**$ 234,059**	**$ 188,328**	**$ 422,387**	$ 67,865	$ 79,364	$ 147,229

	Six Months Ended June 30					
	2021			2020		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 217,814**	**$ 263,986**	**$ 481,800**	$ 151,314	$ 182,198	$ 333,512
Heavy oil	**238,820**	**—**	**238,820**	99,846	—	99,846
NGL	**8,150**	**29,939**	**38,089**	2,196	16,877	19,073
Total oil sales	**464,784**	**293,925**	**758,709**	253,356	199,075	452,431
Natural gas sales	**28,664**	**39,683**	**68,347**	14,813	22,059	36,872
Total petroleum and natural gas sales	**493,448**	**333,608**	**827,056**	268,169	221,134	489,303
Blending and other expense	**(37,087)**	**—**	**(37,087)**	(26,817)	—	(26,817)
Total sales, net of blending and other expense	**$ 456,361**	**$ 333,608**	**$ 789,969**	$ 241,352	$ 221,134	$ 462,486

Total sales, net of blending and other expense, of $422.4 million for Q2/2021 increased $275.2 million from $147.2 million reported for Q2/2020 while total sales, net of blending and other expense, of $790.0 million for YTD 2021 increased $327.5 million from $462.5 million reported for YTD 2020. The increase in total sales in both periods is a result of higher realized pricing due to the increase in benchmark pricing.

In Canada, total sales, net of blending and other expense, was $234.1 million for Q2/2021 which is an increase of $166.2 million from $67.9 million reported for Q2/2020. Total petroleum and natural gas sales increased due to higher realized pricing and higher production for Q2/2021 relative to Q2/2020. Our increased realized price resulted in a $149.1 million increase in total sales, net of blending and other expense, while increased production resulted in a $17.1 million increase in total sales, net of blending and other expense, relative to Q2/2020. Despite lower production, the increase in benchmark prices resulted in our total sales, net of blending and other expense, increasing to $456.4 million in YTD 2021 from $241.4 million in YTD 2020.

In the U.S., petroleum and natural gas sales were $188.3 million for Q2/2021 which is an increase of $109.0 million from $79.4 million reported for Q2/2020. Total petroleum and natural gas sales increased $110.9 million due to higher realized pricing for Q2/2021 relative to Q2/2020 while lower production resulted in a $2.0 million decrease in total sales, net of blending and other expense relative to Q2/2020. Higher realized pricing in YTD 2021 resulted in petroleum and natural gas sales of $333.6 million which was $112.5 million higher than $221.1 million in YTD 2020 despite lower production in YTD 2021 relative to YTD 2020.

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, 2021 and 2020.

	Three Months Ended June 30					
	2021			2020		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 26,193**	**$ 55,338**	**$ 81,531**	$ 6,157	$ 22,999	$ 29,156
Average royalty rate [1]	**11.2 %**	**29.4 %**	**19.3 %**	9.1 %	29.0 %	19.8 %
Royalties per boe	**$ 6.10**	**$ 17.91**	**$ 11.04**	$ 1.80	$ 7.26	$ 4.42

	Six Months Ended June 30					
	2021			2020		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 50,857**	**$ 97,624**	**$ 148,481**	$ 21,675	$ 64,201	$ 85,876
Average royalty rate [1]	**11.1 %**	**29.3 %**	**18.8 %**	9.0 %	29.0 %	18.6 %
Royalties per boe	**$ 5.66**	**$ 17.76**	**$ 10.26**	$ 2.38	$ 9.94	$ 5.52

(1) Average royalty rate is calculated as royalties divided by total sales, net of blending and other expense.

Royalties for Q2/2021 were $81.5 million or 19.3% of total sales, net of blending and other expense compared to $29.2 million or 19.8% for Q2/2020. Total royalties for YTD 2021 were $148.5 million or 18.8% of total sales, net of blending and other expense, compared to $85.9 million or 18.6% for YTD 2020. Total royalty expense was higher for Q2/2021 and YTD 2021 due to higher total sales, net of blending and other expense, relative to the same periods of 2020. Our royalty rates of 19.3% for Q2/2021 and 18.8% for YTD 2021 were consistent with 19.8% for Q2/2020 and 18.6% for YTD 2020. Our average royalty rate of 18.8% for YTD 2021 is consistent with expectations and is slightly above our annual guidance range of 18.0% - 18.5% for 2021 due to higher than expected benchmark commodity prices and strong realized pricing in Canada.

Our Canadian royalty rates of 11.2% for Q2/2021 and 11.1% for YTD 2021 were higher than 9.1% for Q2/2020 and 9.0% for YTD 2020 due to higher benchmark commodity prices which resulted in a higher royalty rate on our Canadian properties in 2021 relative to 2020. In the U.S., royalties averaged 29.4% and 29.3% of total sales for Q2/2021 and YTD 2021, respectively, which is consistent with 29.0% for the same periods of 2020 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	2021			2020		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 61,793**	**$ 21,108**	**$ 82,901**	$ 49,162	$ 24,518	$ 73,680
Operating expense per boe	**$ 14.39**	**$ 6.83**	**$ 11.22**	$ 14.33	$ 7.74	$ 11.17

Six Months Ended June 30	2021			2020		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 123,154**	**$ 40,295**	**$ 163,449**	$ 128,084	$ 50,066	$ 178,150
Operating expense per boe	**$ 13.72**	**$ 7.33**	**$ 11.29**	$ 14.08	$ 7.75	$ 11.45

Total operating expense was $82.9 million ($11.22/boe) for Q2/2021 and $163.4 million ($11.29/boe) for YTD 2021 compared to $73.7 million ($11.17/boe) for Q2/2020 and $178.2 million ($11.45/boe) for YTD 2020. Total operating expense for Q2/2021 increased with production relative to Q2/2020 while total operating expense for YTD 2021 decreased with production relative to YTD 2020. Operating expense of $11.29/boe for YTD 2021 is consistent with expectations and our revised annual guidance range of $11.25 - $12.00/boe.

In Canada, operating expense was $61.8 million ($14.39/boe) for Q2/2021 and $123.2 million ($13.72/boe) for YTD 2021 compared to $49.2 million ($14.33/boe) for Q2/2020 and $128.1 million ($14.08/boe) for YTD 2020. Operating expense in Canada for Q2/2021 has increased with higher production relative to Q2/2020 while operating expense for YTD 2021 decreased with lower production relative to YTD 2020. Per unit operating expense of $14.39/boe for Q2/2021 and $13.72/boe for YTD 2021 was relatively consistent with $14.33/boe for Q2/2020 and $14.08/boe for YTD 2020.

U.S. operating expense was $21.1 million ($6.83/boe) for Q2/2021 and $40.3 million ($7.33/boe) for YTD 2021 compared to $24.5 million ($7.74/boe) for Q2/2020 and $50.1 million ($7.75/boe) for YTD 2020. Lower operating expense is primarily a result of lower U.S. production in Q2/2021 and YTD 2021 relative to Q2/2020 and YTD 2020. Expressed in U.S. dollars, per unit operating expense was US$5.56/boe in Q2/2021 and US$5.88/boe for YTD 2021 which was relatively consistent with US$5.58/boe for Q2/2020 and US$5.68/boe for YTD 2020.

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, 2021 and 2020.

Three Months Ended June 30	2021			2020		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 7,486**	**$ —**	**$ 7,486**	$ 5,031	$ —	$ 5,031
Transportation expense per boe	**$ 1.74**	**$ —**	**$ 1.01**	$ 1.47	$ —	$ 0.76

Six Months Ended June 30	2021			2020		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 16,274**	**$ —**	**$ 16,274**	$ 15,373	$ —	$ 15,373
Transportation expense per boe	**$ 1.81**	**$ —**	**$ 1.12**	$ 1.69	$ —	$ 0.99

Transportation expense was $7.5 million ($1.01/boe) for Q2/2021 and $16.3 million ($1.12/boe) for YTD 2021 compared to $5.0 million ($0.76/boe) for Q2/2020 and $15.4 million ($0.99/boe) for YTD 2020. The increase in total transportation expense in both periods of 2021 relative to 2020 is the result of higher production in Canada. Per unit transportation expense in Canada of $1.74/boe for Q2/2021 and $1.81/boe for YTD 2021 is higher than $1.47/boe for Q2/2020 and $1.69/boe for YTD 2020 due to additional heavy oil production in both periods of 2021 relative to 2020. Per unit transportation expense of $1.12/boe for YTD 2021 is consistent with expectations and was slightly below our revised annual guidance of $1.15 - $1.25/boe.

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 $20.0 million for Q2/2021 and $37.1 million for YTD 2021 compared to $5.5 million for Q2/2020 and $26.8 million for YTD 2020. Higher blending and other expense reflects higher heavy oil sales along with an increase in the cost of blending diluent in 2021 relative to 2020.

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, 2021 and 2020.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2021**	2020	Change	**2021**	2020	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ (38,234)**	$ 13,524	$ (51,758)	**$ (58,275)**	$ 40,169	$ (98,444)
Natural gas	**(790)**	378	(1,168)	**(1,517)**	589	(2,106)
Interest and financing	**—**	(278)	278	**—**	(284)	284
Total	**$ (39,024)**	$ 13,624	$ (52,648)	**$ (59,792)**	$ 40,474	$ (100,266)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ (81,069)**	$ (71,936)	$ (9,133)	**$ (166,539)**	$ 27,873	$ (194,412)
Natural gas	**(7,898)**	1,181	(9,079)	**(9,285)**	1,059	(10,344)
Interest and financing	**—**	204	(204)	**—**	(474)	474
Equity total return swap ("Equity TRS")	**4,484**	1,265	3,219	**5,357**	(1,749)	7,106
Total	**$ (84,483)**	$ (69,286)	$ (15,197)	**$ (170,467)**	$ 26,709	$ (197,176)
Total financial derivatives gain (loss)						
Crude oil	**$ (119,303)**	$ (58,412)	$ (60,891)	**$ (224,814)**	$ 68,042	$ (292,856)
Natural gas	**(8,688)**	1,559	(10,247)	**(10,802)**	1,648	(12,450)
Interest and financing	**—**	(74)	74	**—**	(758)	758
Equity TRS	**4,484**	1,265	3,219	**5,357**	(1,749)	7,106
Total	**$ (123,507)**	$ (55,662)	$ (67,845)	**$ (230,259)**	$ 67,183	$ (297,442)

We recorded total financial derivative losses of $123.5 million for Q2/2021 and $230.3 million for YTD 2021 compared to a loss of $55.7 million for Q2/2020 and a gain of $67.2 million for YTD 2020. Realized financial derivatives losses of $39.0 million for Q2/2021 and $59.8 million for YTD 2021 were primarily a result of the market prices for crude oil settling at levels above those set in our derivative contracts. Unrealized losses of $84.5 million for Q2/2021 and $170.5 million for YTD 2021 were primarily a result of the increase in forecasted crude oil pricing used to revalue our crude oil contracts in place at June 30, 2021 relative to December 31, 2020 along with the valuation of new contracts entered during the period. The fair value of our financial derivative contracts resulted in a net liability of $192.2 million at June 30, 2021 compared to a net liability of $21.7 million at December 31, 2020.

We had the following commodity financial derivative contracts as at July 28, 2021.

	Period	Volume	Price/Unit [1]	Index
Oil				
Basis Swap	Jul 2021 to Dec 2021	8,000 bbl/d	WTI less US$13.41/bbl	WCS
Basis Swap	Jan 2022 to Dec 2022	9,000 bbl/d	WTI less US$12.47/bbl	WCS
Basis Swap [4]	Jan 2022 to Dec 2022	1,000 bbl/d	WTI less US$13.00/bbl	WCS
Basis Swap	Jul 2021 to Dec 2021	7,500 bbl/d	WTI less US$5.03/bbl	MSW
Basis Swap	Jan 2022 to Dec 2022	1,000 bbl/d	WTI less US$4.75/bbl	MSW
Basis Swap [4]	Jan 2022 to Dec 2022	1,000 bbl/d	WTI less US$4.50/bbl	MSW
Fixed Sell	Jul 2021 to Dec 2021	4,000 bbl/d	US$45.00/bbl	WTI
3-way option [2]	Jul 2021 to Dec 2021	500 bbl/d	US$35.00/US$45.00/US$49.03	WTI
3-way option [2]	Jul 2021 to Dec 2021	1,500 bbl/d	US$35.00/US$45.00/US$49.10	WTI
3-way option [2]	Jul 2021 to Dec 2021	3,500 bbl/d	US$35.00/US$45.00/US$49.50	WTI
3-way option [2]	Jul 2021 to Dec 2021	10,000 bbl/d	US$35.00/US$45.00/US$55.00	WTI
3-way option [2]	Jul 2021 to Dec 2021	2,000 bbl/d	US$37.00/US$42.50/US$48.00	WTI
3-way option [2]	Jan 2022 to Dec 2022	1,500 bbl/d	US$40.00/US$50.00/US$58.10	WTI
3-way option [2]	Jan 2022 to Dec 2022	2,000 bbl/d	US$46.00/US$56.00/US$66.72	WTI
3-way option [2]	Jan 2022 to Dec 2022	2,500 bbl/d	US$47.00/US$57.00/US$67.00	WTI
3-way option [2]	Jan 2022 to Dec 2022	2,500 bbl/d	US$50.00/US$60.00/US$70.00	WTI
3-way option [2]	Jan 2022 to Dec 2022	2,000 bbl/d	US$53.00/US$63.50/US$72.90	WTI
Swaption [3]	Jan 2022 to Dec 2022	5,000 bbl/d	US$53.00/bbl	WTI
Swaption [3]	Jan 2022 to Dec 2022	5,000 bbl/d	US$54.00/bbl	WTI
Natural Gas				
Fixed Sell	Jul 2021 to Dec 2021	16,000 GJ/d	$2.36/GJ	AECO 7A
Fixed Sell	Jan 2022 to Dec 2022	5,000 GJ/d	$2.53/GJ	AECO 7A
Fixed Sell	Jul 2021 to Dec 2021	2,500 GJ/d	$2.40/GJ	AECO 5A
Fixed Sell	Jan 2022 to Dec 2022	6,250 GJ/d	$2.59/GJ	AECO 5A
Fixed Sell [4]	Jan 2022 to Dec 2022	6,000 GJ/d	$2.95/GJ	AECO 5A
Fixed Sell	Jul 2021 to Dec 2021	12,000 mmbtu/d	US$2.70/mmbtu	NYMEX
Fixed Sell	Jan 2022 to Dec 2022	1,000 mmbtu/d	US$2.94/mmbtu	NYMEX
3-way option [2]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.25/US$2.75/US$3.06	NYMEX
3-way option [2]	Jan 2022 to Dec 2022	1,500 mmbtu/d	US$2.60/US$2.91/US$3.56	NYMEX
3-way option [2]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.60/US$3.00/US$3.83	NYMEX
3-way option [2]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.65/US$2.90/US$3.40	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.

(3) For these contracts, the counterparty has the right, if exercised on December 31, 2021, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

(4) Contracts entered subsequent to June 30, 2021.

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, 2021 and 2020.

	Three Months Ended June 30					
	2021			2020		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**47,205**	**33,957**	**81,162**	37,691	34,817	72,508
Operating netback:						
Total sales, net of blending and other expense	**$ 54.49**	**$ 60.95**	**$ 57.19**	$ 19.79	$ 25.05	$ 22.31
Less:						
Royalties	**(6.10)**	**(17.91)**	**(11.04)**	(1.80)	(7.26)	(4.42)
Operating expense	**(14.39)**	**(6.83)**	**(11.22)**	(14.33)	(7.74)	(11.17)
Transportation expense	**(1.74)**	**—**	**(1.01)**	(1.47)	—	(0.76)
Operating netback	**$ 32.26**	**$ 36.21**	**$ 33.92**	$ 2.19	$ 10.05	$ 5.96
Realized financial derivatives (loss) gain	**—**	**—**	**(5.28)**	—	—	2.06
Operating netback after financial derivatives	**$ 32.26**	**$ 36.21**	**$ 28.64**	$ 2.19	$ 10.05	$ 8.02

	Six Months Ended June 30					
	2021			2020		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**49,609**	**30,369**	**79,978**	49,976	35,503	85,479
Operating netback:						
Total sales, net of blending and other expense	**$ 50.82**	**$ 60.69**	**$ 54.57**	$ 26.53	$ 34.22	$ 29.73
Less:						
Royalties	**(5.66)**	**(17.76)**	**(10.26)**	(2.38)	(9.94)	(5.52)
Operating expense	**(13.72)**	**(7.33)**	**(11.29)**	(14.08)	(7.75)	(11.45)
Transportation expense	**(1.81)**	**—**	**(1.12)**	(1.69)	—	(0.99)
Operating netback	**$ 29.63**	**$ 35.60**	**$ 31.90**	$ 8.38	$ 16.53	$ 11.77
Realized financial derivatives (loss) gain	**—**	**—**	**(4.13)**	—	—	2.60
Operating netback after financial derivatives	**$ 29.63**	**$ 35.60**	**$ 27.77**	$ 8.38	$ 16.53	$ 14.37

Our operating netback of $33.92/boe for Q2/2021 and $31.90/boe for YTD 2021 was higher than $5.96/boe for Q2/2020 and $11.77/boe for YTD 2020 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 $12.23/boe for Q2/2021 and $12.41/boe for YTD 2021 was consistent with $11.93/boe for Q2/2020 and $12.44/boe for YTD 2020. Including realized gains and losses on financial derivatives our operating netback was $28.64/boe for Q2/2021 and $27.77/boe for YTD 2021 compared to $8.02/boe for Q2/2020 and $14.37/boe for YTD 2020.

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, 2021 and 2020.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2021**	2020	Change	**2021**	2020	Change
Gross general and administrative expense	**$ 11,158**	$ 7,476	$ 3,682	**$ 20,619**	$ 19,364	$ 1,255
Overhead recoveries	**(548)**	(38)	(510)	**(1,276)**	(2,151)	875
General and administrative expense	**$ 10,610**	$ 7,438	$ 3,172	**$ 19,343**	$ 17,213	$ 2,130
General and administrative expense per boe	**$ 1.44**	$ 1.13	$ 0.31	**$ 1.34**	$ 1.11	$ 0.23

G&A expense was $10.6 million ($1.44/boe) for Q2/2021 and $19.3 million ($1.34/boe) for YTD 2021 compared to $7.4 million ($1.13/boe) for Q2/2020 and $17.2 million ($1.11/boe) for YTD 2020. G&A expense for Q2/2021 and YTD 2021 was higher relative to the same periods of 2020 as employee and director compensation was reduced from Q2/2020 to Q4/2020 and the Company received benefits under the Canadian Emergency Wage Subsidy program in 2020.

G&A expense of $1.34/boe is consistent with expectations and is slightly below our revised annual guidance of $1.45/boe for 2021.

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, 2021 and 2020.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2021**	2020	Change	**2021**	2020	Change
Interest on credit facilities	**$ 3,250**	$ 4,248	$ (998)	**$ 6,586**	$ 8,383	$ (1,797)
Interest on long-term notes	**20,246**	23,015	(2,769)	**41,253**	47,288	(6,035)
Interest on lease obligations	**58**	124	(66)	**$ 118**	$ 251	(133)
Cash interest	**$ 23,554**	$ 27,387	$ (3,833)	**$ 47,957**	$ 55,922	$ (7,965)
Accretion of debt issue costs	**790**	665	125	**1,539**	5,107	(3,568)
Accretion of asset retirement obligations	**3,367**	2,178	1,189	**5,665**	5,109	556
Gain on redemption of long-term notes	**(357)**	—	(357)	**(357)**	—	(357)
Early redemption expense	**—**	—	—	**—**	3,312	(3,312)
Financing and interest expense	**$ 27,354**	$ 30,230	$ (2,876)	**$ 54,804**	$ 69,450	$ (14,646)
Cash interest per boe	**$ 3.19**	$ 4.15	$ (0.96)	**$ 3.31**	$ 3.59	$ (0.28)
Financing and interest expense per boe	**$ 3.70**	$ 4.58	$ (0.88)	**$ 3.79**	$ 4.46	$ (0.67)

Financing and interest expense was $27.4 million ($3.70/boe) for Q2/2021 and $54.8 million ($3.79/boe) for YTD 2021 compared to $30.2 million ($4.58/boe) for Q2/2020 and $69.5 million ($4.46/boe) for YTD 2020.

Cash interest of $23.6 million ($3.19/boe) for Q2/2021 and $48.0 million ($3.31/boe) for YTD 2021 is lower than $27.4 million ($4.15/boe) for Q2/2020 and $55.9 million ($3.59/boe) for YTD 2020 primarily due to lower interest on our long-term notes. The reported interest on our U.S. dollar denominated long-term notes was lower as the average principal amount of long-term notes outstanding was lower during YTD 2021 due to the refinancing transactions completed in Q1/2020 along with the strengthening of the Canadian dollar for Q2/2021 and YTD 2021 relative to the same periods of 2020. Interest on our credit facilities was lower in Q2/2021 and YTD 2021 compared to the same periods of 2020 due to lower borrowings on our credit facilities and lower effective interest rates. The weighted average interest rate applicable to our credit facilities was 2.1% for Q2/2021 and YTD 2021 compared to 2.3% and 2.7% in Q2/2020 and YTD 2020, respectively.

Financing and interest expense for YTD 2021 was lower than YTD 2020 which included the accelerated amortization of debt issue costs and $3.3 million of early redemption expense associated with the redemption of notes in Q1/2020.

Cash interest expense of $3.31/boe for YTD 2021 is slightly above our revised annual guidance of $3.27/boe as the strength of the Canadian dollar has reduced our interest expense. We expect cash interest expense of $95 million ($3.27/boe) for 2021.

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 $3.0 million for Q2/2021 and $4.0 million for YTD 2021 which is higher than $1.8 million for Q2/2020 and $2.1 million for YTD 2020 due to a higher amount of acreage expiring in both periods of 2021 relative to 2020.

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, 2021 and 2020.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2021**	2020	Change	**2021**	2020	Change
Depletion	**$ 101,751**	$ 102,622	$ (871)	**$ 202,490**	$ 282,040	$ (79,550)
Depreciation	**1,304**	1,918	(614)	**2,577**	3,886	(1,309)
Depletion and depreciation	**$ 103,055**	$ 104,540	$ (1,485)	**$ 205,067**	$ 285,926	$ (80,859)
Depletion and depreciation per boe	**$ 13.95**	$ 15.84	$ (1.89)	**$ 14.17**	$ 18.38	$ (4.21)

Depletion and depreciation expense was $103.1 million ($13.95/boe) for Q2/2021 and $205.1 million ($14.17/boe) for YTD 2021 compared to $104.5 million ($15.84/boe) for Q2/2020 and $285.9 million ($18.38/boe) for YTD 2020. Total depletion and depreciation expense and the depletion rate per boe were slightly lower in Q2/2021 due to a stronger CAD/USD exchange rate relative to Q2/2020 which resulted in lower depletion expense reported in Canadian dollars for our U.S. oil and gas properties. This decrease was partially offset by higher depletion expense for our Canadian properties due to higher production in Q2/2021 relative to Q2/2020.

Total depletion and depreciation expense and the depletion rate per boe were lower in YTD 2021 compared to YTD 2020 as we recorded a $2.2 billion net impairment loss to our oil and gas properties in 2020 which reduced the depletable base of our oil and gas properties for YTD 2021.

Impairment

At June 30, 2021, we identified indicators of impairment reversal for oil and gas properties in each of our six CGU's due to the increase in forecasted commodity prices. We recorded an impairment reversal of $1.1 billion at June 30, 2021 as the estimated recoverable amount of all six CGUs exceeded their carrying value. No indicators of impairment or impairment reversal were identified for the Company's E&E assets at June 30, 2021.

At June 30, 2021, the recoverable amount of the Company's CGUs were calculated using the following benchmark reference prices for the years 2021 to 2030 adjusted for commodity differentials specific to the Company. The prices and costs subsequent to 2030 have been adjusted for inflation at an annual rate of 2.0%.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
WTI crude oil (US$/bbl)	71.33	67.20	63.95	63.23	64.50	65.79	67.10	68.44	69.81	71.21
WCS heavy oil (CA$/bbl)	72.22	66.84	61.73	60.70	61.91	63.15	64.42	65.70	67.02	68.36
LLS crude oil (US$/bbl)	72.17	68.53	65.80	65.10	66.39	67.71	69.05	70.42	71.82	73.26
Edmonton par oil (CA$/bbl)	83.20	78.27	74.06	73.05	74.51	76.00	77.52	79.07	80.66	82.27
Henry Hub gas (US$/mmbtu)	3.42	3.19	2.92	2.96	3.02	3.08	3.14	3.21	3.27	3.34
AECO gas (CA$/mmbtu)	3.46	3.13	2.72	2.71	2.76	2.82	2.88	2.94	2.99	3.05
Exchange rate (CAD/USD)	1.24	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25

The following table summarizes the recoverable amount and impairment reversal at June 30, 2021 and demonstrates the sensitivity of the estimated recoverable amount of the Company's CGUs comprising oil and gas properties to reasonably possible changes in key assumptions inherent in the estimate.

	Recoverable amount	Impairment reversal	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU	$ 57,891	$ 15,000	$ 1,000	$ 1,000	$ 8,000
Peace River CGU	238,714	154,000	4,000	40,000	2,500
Lloydminster CGU	340,730	154,000	12,500	52,000	—
Duvernay CGU (1)	115,157	5,000	45,000	44,500	44,500
Viking CGU	1,338,985	356,000	47,000	89,500	4,500
Eagle Ford CGU	2,015,118	442,415	109,400	103,900	24,400
	$ 4,106,595	$ 1,126,415	$ 218,900	$ 330,900	$ 83,900

(1) The impairment reversal for the Duvernay CGU was limited to total accumulated impairments less subsequent depletion of $5.0 million.

We recorded total net impairments of $2.4 billion for the year ended December 31, 2020 due to significant changes in forecasted commodity prices caused by the COVID-19 pandemic.

At March 31, 2020, we identified indicators of impairment due to the sharp decline in forecasted commodity prices. We performed impairment tests on the E&E assets and oil and gas properties for our six CGUs. We recorded an impairment loss of $2.7 billion in Q1/2020 as the carrying value of the E&E assets and oil and gas properties exceeded the estimated recoverable amounts of the CGUs. The total impairment loss recorded at Q1/2020 included $2.6 billion related to oil and gas properties and $0.1 billion related to E&E assets.

At December 31, 2020, with updated development plans, including capital efficiencies and reduced well costs, reflected in our reserves along with changes in commodity prices, we estimated the recoverable amount for E&E assets and oil and gas properties in each of our six CGUs. We recorded an impairment reversal of $356.1 million at December 31, 2020 as the estimated recoverable amount of the Viking and Eagle Ford CGUs exceeded their carrying value. The total impairment reversal recorded at Q4/2020 includes $341.3 million related to oil and gas properties and $14.8 million related to E&E assets.

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 $2.8 million for Q2/2021 and $5.8 million for YTD 2021 which is consistent with $3.0 million for Q2/2020 and $5.8 million for YTD 2020. The total expense for YTD 2021 is comprised of non-cash compensation expense of $3.2 million related to the Share Award Incentive Plan and cash compensation expense of $2.6 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 our U.S. dollar denominated intercompany notes. The long-term notes and intercompany notes 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)	**2021**	2020	Change	**2021**	2020	Change
Unrealized foreign exchange (gain) loss	**$ (1,792)**	$ (45,516)	$ 12,579	**$ (4,322)**	$ 54,005	$ 26,320
Realized foreign exchange gain	**(464)**	(457)	(7)	**(739)**	(86)	(653)
Foreign exchange (gain) loss	**$ (2,256)**	$ (45,973)	$ 43,717	**$ (5,061)**	$ 53,919	$ (58,980)
CAD/USD exchange rates:						
At beginning of period	**1.2572**	1.4120		**1.2755**	1.2965	
At end of period	**1.2405**	1.3616		**1.2405**	1.3616	

We recorded unrealized foreign exchange gains of $1.8 million for Q2/2021 and $4.3 million for YTD 2021 compared to a gain of $45.5 million for Q2/2020 and a loss of $54.0 million for YTD 2020.

In September 2020, we issued a series of intercompany notes totaling US$751.0 million issued from a Canadian subsidiary to a U.S. subsidiary. We recorded unrealized foreign exchange losses of $12.6 million for Q2/2021 and $26.3 million for YTD 2021 on our intercompany notes issued by our Canadian subsidiary due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2021 compared to March 31, 2021 and December 31, 2020, respectively. There were no unrealized foreign exchange gains or losses on our intercompany notes recorded in Q2/2020 or YTD 2020.

We recorded unrealized foreign exchange gains on our long-term notes of $14.4 million for Q2/2021 and $30.6 million for YTD 2021 due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2021 compared to March 31, 2021 and December 31, 2020, respectively. This compares to an unrealized foreign exchange gain of $45.5 million for Q2/2020 due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2020 compared to March 31, 2020, and an unrealized foreign exchange loss of $54.0 million for YTD 2020 due to the weakening of the Canadian dollar at June 30, 2020 compared to December 31, 2019.

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 realized foreign exchange gains of $0.5 million for Q2/2021 and $0.7 million for YTD 2021 compared to $0.5 million for Q2/2020 and $0.1 million for YTD 2020.

Income Taxes

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2021**	2020	Change	**2021**	2020	Change
Current income tax expense	**$ 568**	$ 89	$ 479	**$ 408**	$ 558	$ (150)
Deferred income tax expense (recovery)	**56,051**	21,002	35,049	**61,715**	(262,177)	323,892
Total income tax expense (recovery)	**$ 56,619**	$ 21,091	$ 35,528	**$ 62,123**	$ (261,619)	$ 323,742

Current income tax expense was $0.6 million for Q2/2021 and $0.4 million for YTD 2021 compared to $0.1 million for Q2/2020 and $0.6 million for YTD 2020.

We recorded deferred tax expense of $56.1 million for Q2/2021 and $61.7 million for YTD 2021 compared to an expense of $21.0 million for Q2/2020 and a recovery of $262.2 million for YTD 2020. The deferred tax expense recorded in YTD 2021 is primarily related to the impairment reversal recorded in YTD 2021 whereas the deferred tax recovery recorded in YTD 2020 is primarily related to the impairment loss recorded in YTD 2020.

As disclosed in the 2020 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 (Loss) and Adjusted Funds Flow

The components of adjusted funds flow and net income or loss for the three and six months ended June 30, 2021 and 2020 are set forth in the following table.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2021**	2020	Change	**2021**	2020	Change
Petroleum and natural gas sales	**$ 442,354**	$ 152,689	$ 289,665	**$ 827,056**	$ 489,303	$ 337,753
Royalties	**(81,531)**	(29,156)	(52,375)	**(148,481)**	(85,876)	(62,605)
Revenue, net of royalties	**360,823**	123,533	237,290	**678,575**	403,427	275,148
Expenses						
Operating	**(82,901)**	(73,680)	(9,221)	**(163,449)**	(178,150)	14,701
Transportation	**(7,486)**	(5,031)	(2,455)	**(16,274)**	(15,373)	(901)
Blending and other	**(19,967)**	(5,460)	(14,507)	**(37,087)**	(26,817)	(10,270)
Operating netback	**$ 250,469**	$ 39,362	$ 211,107	**$ 461,765**	$ 183,087	$ 278,678
General and administrative	**(10,610)**	(7,438)	(3,172)	**(19,343)**	(17,213)	(2,130)
Cash financing and interest	**(23,554)**	(27,387)	3,833	**(47,957)**	(55,922)	7,965
Realized financial derivatives (loss) gain	**(39,024)**	13,624	(52,648)	**(59,792)**	40,474	(100,266)
Realized foreign exchange gain	**464**	457	7	**739**	86	653
Other income (expense)	**(170)**	(24)	(146)	**62**	2,007	(1,945)
Current income tax expense	**(568)**	(89)	(479)	**(408)**	(558)	150
Cash share-based compensation	**(1,124)**	(618)	(506)	**(2,601)**	(1,139)	(1,462)
Adjusted funds flow	**$ 175,883**	$ 17,887	$ 157,996	**$ 332,465**	$ 150,822	$ 181,643
Exploration and evaluation	**(3,005)**	(1,831)	(1,174)	**(3,952)**	(2,091)	(1,861)
Depletion and depreciation	**(103,055)**	(104,540)	1,485	**(205,067)**	(285,926)	80,859
Non-cash share-based compensation	**(1,646)**	(2,375)	729	**(3,150)**	(4,637)	1,487
Non-cash financing and accretion	**(3,800)**	(2,843)	(957)	**(6,847)**	(13,528)	6,681
Non-cash other income	**676**	—	676	**1,664**	—	1,664
Unrealized financial derivatives (loss) gain	**(84,483)**	(69,286)	(15,197)	**(170,467)**	26,709	(197,176)
Unrealized foreign exchange gain (loss)	**1,792**	45,516	(43,724)	**4,322**	(54,005)	58,327
Gain on dispositions	**274**	11	263	**3,980**	148	3,832
Impairment	**1,126,414**	—	1,126,414	**1,126,414**	(2,716,349)	3,842,763
Deferred income tax (expense) recovery	**(56,051)**	(21,002)	(35,049)	**(61,715)**	262,177	(323,892)
Net income (loss) for the period	**$ 1,052,999**	$ (138,463)	$ 1,191,462	**$ 1,017,647**	$(2,636,680)	$ 3,654,327

We generated adjusted funds flow of $175.9 million for Q2/2021 and $332.5 million for YTD 2021 compared to $17.9 million for Q2/2020 and $150.8 million for YTD 2020. The increase in adjusted funds flow for both periods of 2021 was primarily due to higher operating netback which increased $211.1 million from Q2/2020 and $278.7 million from YTD 2020 as a result of higher commodity prices which increased revenue, net of royalties. The increase in operating netback was partially offset by realized losses on financial derivatives of $39.0 million for Q2/2021 and $59.8 million for YTD 2021 due to the increase in oil and natural gas benchmark prices relative to Q2/2020 and YTD 2020 when we recorded realized gains on financial derivatives of $13.6 million and $40.5 million, respectively.

We reported net income of $1.05 billion for Q2/2021 and $1.02 billion for YTD 2021 compared to a net loss of $138.5 million reported for Q2/2020 and a net loss of $2.64 billion for YTD 2020. Net income in both periods of 2021 is a result of an impairment reversal of $1.13 billion recorded in Q2/2021 compared to YTD 2020 when we recorded an impairment loss of $2.72 billion.

Other Comprehensive Income (Loss)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets which includes a series of intercompany debt instruments outstanding between our Canadian and U.S. subsidiaries. Foreign exchange gains or losses on the debt owing from the U.S. subsidiary is recorded in other comprehensive income and the offsetting foreign exchange gain or loss on debt owed to the Canadian subsidiary is included in profit and loss for the period.

The foreign currency translation losses of $0.1 million for Q2/2021 and $7.2 million for YTD 2021 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the Canadian dollar strengthening relative to the U.S. dollar at June 30, 2021 compared to March 31, 2021 and December 31, 2020. The CAD/USD exchange rate was 1.2405 CAD/USD as at June 30, 2021 compared to 1.2572 CAD/USD at March 31, 2021 and 1.2755 CAD/USD at December 31, 2020.

Capital Expenditures

Capital expenditures for the three and six months ended June 30, 2021 and 2020 are summarized as follows.

	Three Months Ended June 30					
	2021			2020		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 23,018**	**$ 30,911**	**$ 53,929**	$ 8	$ 6,768	$ 6,776
Facilities	**4,682**	**9**	**4,691**	2,693	—	2,693
Land, seismic and other	**2,687**	**178**	**2,865**	228	155	383
Total exploration and development	**$ 30,387**	**$ 31,098**	**$ 61,485**	$ 2,929	$ 6,923	$ 9,852
Total acquisitions, net of proceeds from divestitures	**$ (18)**	**$ —**	**$ (18)**	$ (11)	$ —	$ (11)

	Six Months Ended June 30					
	2021			2020		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 62,052**	**$ 71,633**	**$ 133,685**	$ 99,545	$ 59,839	$ 159,384
Facilities	**7,197**	**13**	**7,210**	21,697	299	21,996
Land, seismic and other	**3,641**	**537**	**4,178**	4,798	451	5,249
Total exploration and development	**$ 72,890**	**$ 72,183**	**$ 145,073**	$ 126,040	$ 60,589	$ 186,629
Total acquisitions, net of proceeds from divestitures	**$ (221)**	**$ —**	**$ (221)**	$ (51)	$ —	$ (51)

Exploration and development expenditures were $61.5 million for Q2/2021 and $145.1 million for YTD 2021 compared to $9.9 million for Q2/2020 and $186.6 million for YTD 2020. Expenditures in Q2/2021 were higher compared to Q2/2020 as development activity was reduced in Canada and the U.S. following the sharp decline in commodity prices in March 2020.

In Canada, we invested $30.4 million on exploration and development activities in Q2/2021 which is $27.5 million higher than $2.9 million in Q2/2020. Exploration and development expenditures of $30.4 million for Q2/2021 included costs associated with drilling 16 (16.0 net) light oil wells, 2 (2.0 net) heavy oil wells, and investing $4.7 million on facilities. Exploration and development expenditures of $2.9 million for Q2/2020 reflects the suspension of drilling and completion operations following the sharp decline in crude oil prices in March 2020. Exploration and development expenditures of $72.9 million for YTD 2021 included costs associated with drilling 53 (52.2 net) light oil wells, 7 (3.9 net) heavy oil wells, 1 (1.0 net) natural gas well, and investing $7.2 million on facilities. Exploration and development expenditures of $126.0 million for YTD 2020 included costs associated with drilling 74 (71.2 net) light oil wells, 33 (33.0 net) heavy oil wells, and investing $21.7 million on facilities.

Total U.S. exploration and development expenditures were $31.1 million for Q2/2021 which is $24.2 million higher than $6.9 million for Q2/2020. Exploration and development expenditures for Q2/2021 included costs associated with drilling 16 (1.7 net) wells along with 38 (10.2 net) wells that were brought on production. Exploration and development expenditures of $6.9 million for Q2/2020 reflects reduced drilling and completion activity following the sharp decline in crude oil pricing in March 2020 and includes final costs associated with 17 (4.6 net) wells that were brought on production during April 2020. Exploration and development expenditures of $72.2 million for YTD 2021 included costs associated with drilling 41 (9.2 net) wells along with 62 (17.2 net) wells that were brought on production. Exploration and development expenditures of $60.6 million for YTD 2020 included costs associated with drilling 17 (3.8 net) wells along with 47 (10.7 net) wells that were brought on production.

Our exploration and development expenditures for YTD 2021 are consistent with expectations and we continue to forecast expenditures of $285 - $315 million for 2021.

CAPITAL RESOURCES AND LIQUIDITY

Our objective for capital management involves maintaining 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, 2021, our capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables and the credit facilities.

The capital-intensive nature of our operations requires us to maintain adequate sources of liquidity to fund ongoing capital programs. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties. We believe that internally generated adjusted funds flow and availability under our credit facilities will provide sufficient liquidity to fund our planned capital expenditures. Adjusted funds flow depends on a number of factors, including commodity prices, production and sales volumes, royalties, operating expenses, taxes and foreign exchange rates. In order to manage our capital structure and liquidity, we may from time-to-time issue or repurchase 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.

Management of debt levels is a priority for Baytex in order to sustain operations and support our long-term plans. At June 30, 2021, net debt of $1.63 billion was $218.0 million lower than $1.85 billion at December 31, 2020. The decrease in net debt is primarily a result of free cash flow of $183.0 million generated during YTD 2021 being allocated to debt repayment along with a $35.0 million decrease in the reported amount of our U.S. dollar denominated net debt due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2021 compared to December 31, 2020.

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, 2021, our net debt to adjusted funds flow ratio was 3.3 compared to a ratio of 5.9 as at December 31, 2020. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2020 is attributed to a $218.0 million decrease in net debt as at June 30, 2021 combined with higher adjusted funds flow for the twelve months ended June 30, 2021.

Credit Facilities

At June 30, 2021, the principal amount of credit facilities and letters of credit outstanding was $501.4 million under our credit facilities that total approximately $1.0 billion. Our credit facilities include US$575 million of revolving credit facilities and a $300 million non-revolving term loan (collectively, the "Credit Facilities"). Our Credit Facilities mature on April 2, 2024 and will automatically be extended to June 4, 2024 providing we have either refinanced, or have the ability to repay, the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.

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 London Interbank Offered Rates ("LIBOR"), plus applicable margins.

The LIBOR benchmark transition begins on December 31, 2021. Certain tenors of the U.S. dollar LIBOR benchmark will no longer be published as of December 31, 2021 while some tenors will continue to be published through mid-2023. We expect the U.S. dollar LIBOR benchmarks to be replaced with an alternative that will apply to our U.S. dollar borrowing at our option. We do not expect this change to have a material impact to Baytex as U.S. dollar borrowings under the credit facilities can also bear interest at the U.S. base loan rate.

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 2.1% for Q2/2021 and YTD 2021 compared to 2.3% for Q2/2020 and 2.7% for YTD 2020.

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at June 30, 2021.

Covenant Description	Position as at June 30, 2021	Covenant
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0.8:1.0**	3.5:1.0
Interest Coverage (3) (Minimum Ratio)	**6.0:1.0**	2.0:1.0

(1) "Senior Secured Debt" is defined as the principal amount of the credit facilities and other secured obligations identified in the credit agreement. As at June 30, 2021, the Company's Senior Secured Debt totaled $501.4 million which includes $486.6 million of principal amounts outstanding and $14.7 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 (including depletion, depreciation, exploration and evaluation expenses, impairment, deferred income tax expense and recovery, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) 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, 2021 was $592.2 million.

(3) "Interest coverage" is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding accretion of debt issue costs and asset retirement obligations, and is calculated on a trailing twelve-month basis. Financing and interest expenses, excluding accretion of debt issue costs and asset retirement obligations, for the twelve months ended June 30, 2021 were $98.3 million.

Long-Term Notes

We have two series of long-term notes outstanding that total $1.1 billion as at June 30, 2021. The long-term notes do not contain any financial maintenance covenants but contain a debt incurrence covenant that restricts our ability to raise additional debt beyond our existing Credit Facilities and long-term notes.

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"), which were redeemed February 20, 2020, and US$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"). The 5.625% Notes pay interest semi-annually with the principal amount repayable at maturity. As of June 1, 2019, the 5.625% Notes are redeemable at our option, in whole or in part, at specified redemption prices and will be redeemable at par from June 1, 2022 to maturity.

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. Transaction costs of $12.5 million were incurred in conjunction with the issuance which resulted in net proceeds of $652.2 million.

During Q2/2021, we purchased and cancelled US$5.8 million principal of the 5.625% Notes at a discount and recorded a gain of $0.4 million. Subsequent to June 30, 2021, we amended the 2014 note indenture to expand our permitted secured indebtedness to align these amounts with the 2020 indenture. We also used free cash flow generated in the first half of 2021 to repurchase and cancel US$100.0 million principal amount of the 5.625% Notes due 2024 at the call price of 100.938%, plus accrued interest, effective July 28, 2021.

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, 2021, we issued 3.0 million common shares pursuant to our share-based compensation program. As at July 28, 2021, we had 564.2 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. These obligations are of a recurring nature and impact our adjusted funds flow in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of June 30, 2021 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	**$ 200,355**	$ 200,355	$ —	$ —	$ —
Credit facilities [1] [2]	**486,623**	—	486,623	—	—
Long-term notes [2]	**1,109,211**	—	488,986	—	620,225
Interest on long-term notes [3]	**392,641**	81,775	161,290	108,539	41,037
Lease agreements [2]	**9,431**	4,265	3,506	1,660	—
Processing agreements	**5,944**	820	1,037	473	3,614
Transportation agreements	**86,190**	16,119	39,041	19,057	11,973
Total	**$ 2,290,395**	$ 303,334	$ 1,180,483	$ 129,729	$ 676,849

(1) The credit facilities mature on April 2, 2024. Maturity will automatically be extended to June 4, 2024 providing Baytex has either refinanced, or has the ability to repay, the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.
(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

	2021		2020				2019	
($ thousands, except per common share amounts)	**Q2**	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Petroleum and natural gas sales	**442,354**	384,702	233,636	252,538	152,689	336,614	445,895	424,600
Net income (loss)	**1,052,999**	(35,352)	221,160	(23,444)	(138,463)	(2,498,217)	(117,772)	15,151
Per common share - basic	**1.87**	(0.06)	0.39	(0.04)	(0.25)	(4.46)	(0.21)	0.03
Per common share - diluted	**1.85**	(0.06)	0.39	(0.04)	(0.25)	(4.46)	(0.21)	0.03
Adjusted funds flow	**175,883**	156,582	82,176	78,508	17,887	132,935	232,147	213,379
Per common share - basic	**0.31**	0.28	0.15	0.14	0.03	0.24	0.42	0.38
Per common share - diluted	**0.31**	0.28	0.15	0.14	0.03	0.24	0.42	0.38
Exploration and development	**61,485**	83,588	77,809	15,902	9,852	176,777	153,117	139,085
Canada	**30,387**	42,503	45,030	3,882	2,929	123,110	104,460	96,774
U.S.	**31,098**	41,085	32,779	12,020	6,923	53,667	48,657	42,311
Acquisitions, net of divestitures	**(18)**	(203)	(33)	(98)	(11)	(40)	563	(30)
Net debt	**1,629,629**	1,758,894	1,847,601	1,906,079	1,994,953	2,051,617	1,871,791	1,971,339
Total assets	**4,438,162**	3,338,408	3,408,096	3,156,414	3,267,820	3,441,040	5,914,083	6,233,875
Common shares outstanding	**564,182**	564,111	561,227	561,163	560,545	560,483	558,305	557,972
Daily production								
Total production (boe/d)	**81,162**	78,780	70,475	77,814	72,508	98,452	96,360	94,927
Canada (boe/d)	**47,205**	52,039	45,321	49,164	37,691	62,262	57,794	58,134
U.S. (boe/d)	**33,957**	26,741	25,154	28,650	34,817	36,190	38,566	36,793
Benchmark prices								
WTI oil (US$/bbl)	**66.07**	57.84	42.66	40.93	27.85	46.17	56.96	56.45
WCS heavy ($/bbl)	**67.03**	57.46	43.46	42.40	22.70	34.48	54.29	58.39
Edmonton Light ($/bbl)	**77.28**	66.58	50.24	49.83	29.85	51.43	58.10	68.41
CAD/USD avg exchange rate	**1.2279**	1.2663	1.3031	1.3316	1.3860	1.3445	1.3201	1.3207
AECO gas ($/mcf)	**2.85**	2.93	2.77	2.18	1.91	2.14	2.34	1.04
NYMEX gas (US$/mmbtu)	**2.83**	2.69	2.66	1.98	1.72	1.95	2.50	2.23
Sales price ($/boe)	**57.19**	51.84	34.35	33.79	22.31	35.19	48.25	47.14
Royalties ($/boe)	**(11.04)**	(9.44)	(5.83)	(5.59)	(4.42)	(6.33)	(8.72)	(8.59)
Operating expense ($/boe)	**(11.22)**	(11.36)	(12.30)	(10.26)	(11.17)	(11.66)	(11.23)	(11.15)
Transportation expense ($/boe)	**(1.01)**	(1.24)	(1.03)	(0.89)	(0.76)	(1.15)	(1.00)	(1.13)
Operating netback ($/boe)	**33.92**	29.80	15.19	17.05	5.96	16.05	27.30	26.27
Financial derivatives gain (loss) ($/boe)	**(5.28)**	(2.93)	2.64	(1.36)	2.06	3.00	2.59	2.39
Operating netback after financial derivatives ($/boe)	**28.64**	26.87	17.83	15.69	8.02	19.05	29.89	28.66

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 was relatively consistent from Q3/2019 to Q1/2020 as relatively stable crude oil prices supported an active development program in Canada and the U.S. until the sharp decline in crude oil prices in March 2020 when we shut-in production in Canada and moderated the pace of activity in the U.S. Commodity prices began to recover in Q4/2020 and have strengthened in YTD 2021 which supported increased development activity and resulted in production of 81,162 boe/d for Q2/2021.

North American benchmark commodity prices were stable throughout 2019 and relatively strong leading into Q1/2020 with the West Texas Intermediate ("WTI") benchmark price averaging US$57.53/bbl in January 2020. Decisions made by Saudi Arabia and Russia to increase production of crude oil as demand was decreasing due to the spread of COVID-19 resulted in a sharp decline in global crude oil prices with WTI averaging US$27.85/bbl in Q2/2020. 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 continued to recover in 2021 with WTI averaging US$66.07/bbl in Q2/2021 as the outlook for demand improved with increasing global mobility. The impact of increased commodity prices is reflected in our realized sales price of $57.19/boe for Q2/2021 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 improved for Q2/2021 compared to lows in 2020 due to strong price realizations and our ongoing efforts to control operating and transportation costs.

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 has decreased from $1.97 billion at Q3/2019 to $1.63 billion at Q2/2021 as free cash flow of $345.7 million generated over the last eight quarters was directed towards debt repayment. Our net debt has also been reduced by a decrease in the CAD/USD exchange rate used to translate our U.S. dollar denominated debt from 1.3244 CAD/USD at Q3/2019 to 1.2405 CAD/USD at Q2/2021.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at June 30, 2021, 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, 2021. 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, 2020.

NYSE LISTING

On March 24, 2020 we received notice from the New York Stock Exchange (“NYSE”) that Baytex was no longer in compliance with one of the NYSE’s continued listing standards because the average closing price of Baytex’s common shares was less than US$1.00 per share over a consecutive 30-day trading period. Baytex did not regain compliance and its common shares were delisted from the NYSE on December 3, 2020.

Baytex's common shares remain registered with the U.S. Securities and Exchange Commission. However, provided that Baytex remains listed on the TSX and the average daily trading volume of Baytex’s common shares in the U.S. is less than 5% of Baytex’s worldwide average daily trading volume over the 12-month period following the delisting, Baytex may be eligible to deregister its common shares at that time. Deregistration of Baytex's common shares would terminate its reporting obligations under the Securities Exchange Act of 1934, as amended.

NON-GAAP AND CAPITAL MEASUREMENT MEASURES

In this MD&A, we refer to certain capital management measures (such as adjusted funds flow, exploration and development expenditures, free cash flow, net debt, operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). While adjusted funds flow, exploration and development expenditures, free cash flow, net debt, operating netback and Bank EBITDA 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. We believe that inclusion of these non-GAAP financial measures provide useful information to investors and shareholders when evaluating the financial results of the Company.

Adjusted Funds Flow

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. In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our operations on a continuing basis.

Adjusted funds flow should not be construed as an alternative to performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income or loss.

The following table reconciles cash flow from operating activities to adjusted funds flow.

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2021**	2020	**2021**	2020
Cash flow from operating activities	**$ 171,876**	$ 25,824	**$ 292,856**	$ 208,391
Change in non-cash working capital	**3,014**	(8,565)	**37,199**	(62,438)
Asset retirement obligations settled	**993**	628	**2,410**	4,869
Adjusted funds flow	**$ 175,883**	$ 17,887	**$ 332,465**	$ 150,822

Exploration and Development Expenditures

We use exploration and development expenditures to measure and evaluate the performance of our capital programs. The total amount of exploration and development expenditures is managed as part of our budgeting process and can vary from period to period depending on the availability of adjusted funds flow and other sources of liquidity. We eliminate changes in non-cash working capital, acquisition and dispositions, and additions to other plant and equipment from investing activities as these amounts are generated by activities outside of our programs to explore and develop our existing properties.

Changes in non-cash working capital are eliminated in the determination of exploration and development expenditures as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our operations on a continuing basis. Our capital budgeting process is focused on programs to explore and develop our existing properties, accordingly, cash flows arising from acquisition and disposition activities are eliminated as we analyze these activities on a transaction by transaction basis separately from our analysis of the performance of our capital programs. Additions to other plant and equipment is primarily comprised of expenditures on corporate assets which do not generate incremental oil and natural gas production and are therefore analyzed separately from our evaluation of the performance of our exploration and development programs.

The following table reconciles cash flow used in investing activities to exploration and development expenditures.

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2021**	2020	**2021**	2020
Cash flow used in investing activities	**$ 44,856**	$ 55,782	**$ 122,033**	$ 216,804
Change in non-cash working capital	**16,931**	(44,566)	**23,230**	(28,239)
Proceeds from dispositions	**18**	11	**246**	51
Property acquisitions	**—**	—	**(25)**	—
Additions to other plant and equipment	**(320)**	(1,375)	**(411)**	(1,987)
Exploration and development expenditures	**$ 61,485**	$ 9,852	**$ 145,073**	$ 186,629

Free Cash Flow

We define free cash flow as adjusted funds flow less exploration and development expenditures (both non-GAAP measures defined above), payments on lease obligations and asset retirement obligations settled. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition opportunities.

The following table provides our computation of free cash flow.

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2021**	2020	**2021**	2020
Adjusted funds flow	**$ 175,883**	$ 17,887	**$ 332,465**	$ 150,822
Exploration and development expenditures	**(61,485)**	(9,852)	**(145,073)**	(186,629)
Payments on lease obligations	**(919)**	(1,468)	**(2,001)**	(2,984)
Asset retirement obligations settled	**(993)**	(628)	**(2,410)**	(4,869)
Free cash flow	**$ 112,486**	$ 5,939	**$ 182,981**	$ (43,660)

Net Debt

We believe that net debt assists in providing a more complete understanding of our financial position and provides a key measure to assess our liquidity. We calculate net debt based on the principal amounts of our credit facilities and long-term notes outstanding, including trade and other payables, cash, and trade and other receivables. 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 total repayment obligation at maturity. The carrying amount of debt issue costs associated with the credit facilities and long-term notes are 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 liquidity or repayment obligation.

The following table summarizes our calculation of net debt.

($ thousands)	**June 30, 2021**	December 31, 2020
Credit facilities [(1)]	**$ 486,623**	$ 651,173
Long-term notes [(1)]	**1,109,211**	1,147,950
Trade and other payables	**200,355**	155,955
Cash	**(1,375)**	—
Trade and other receivables	**(165,185)**	(107,477)
Net debt	**$ 1,629,629**	$ 1,847,601

(1) Principal amount of instruments expressed in Canadian dollars.

Operating Netback

We define operating netback as petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense. Operating netback per boe is the operating netback divided by barrels of oil equivalent production volume for the applicable period. We believe that this measure assists in assessing our ability to generate cash margin on a unit of production basis and is a key measure used to evaluate our operating performance.

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2021**	2020	**2021**	2020
Petroleum and natural gas sales	**$ 442,354**	$ 152,689	**$ 827,056**	$ 489,303
Blending and other expense	**(19,967)**	(5,460)	**(37,087)**	(26,817)
Total sales, net of blending and other expense	**422,387**	147,229	**789,969**	462,486
Royalties	**(81,531)**	(29,156)	**(148,481)**	(85,876)
Operating expense	**(82,901)**	(73,680)	**(163,449)**	(178,150)
Transportation expense	**(7,486)**	(5,031)	**(16,274)**	(15,373)
Operating netback	**250,469**	39,362	**461,765**	183,087
Realized financial derivative (loss) gain	**(39,024)**	13,624	**(59,792)**	40,474
Operating netback after realized financial derivatives	**$ 211,445**	$ 52,986	**$ 401,973**	$ 223,561

Bank EBITDA

Bank EBITDA is used to assess compliance with certain financial covenants contained in our credit facility agreements. Net income is adjusted for the items set forth in the table below as prescribed by the credit facility agreements. The following table reconciles net income or loss to Bank EBITDA on a twelve month rolling basis.

	Twelve Months Ended June 30	
($ thousands)	**2021**	2020
Net income (loss)	**$ 1,215,363**	$ (2,739,301)
Plus:		
Financing and interest	**110,795**	130,032
Unrealized foreign exchange (gain) loss	**(49,095)**	43,511
Unrealized financial derivatives loss	**215,676**	17,520
Current income tax (recovery) expense	**424**	1,561
Deferred income tax expense (recovery)	**162,925**	(314,692)
Depletion and depreciation	**405,521**	646,486
Gain on dispositions	**(4,733)**	(1,329)
Impairment loss (recovery)	**(1,482,543)**	2,904,171
Non-cash items (1)	**17,851**	13,168
Bank EBITDA	**$ 592,184**	$ 701,127

(1) Non-cash items include share-based compensation, exploration and evaluation expense, note redemption premiums, interest on lease obligations, and non-cash other income.

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, 2021.

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 2021 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; the manner in which we fund our planned capital expenditures and monitor and manage our capital resources and liquidity; that a significant portion of our financial obligations will be funded by adjusted funds flow; our expectations with respect to the LIBOR transition and that we do not expect it to have a material impact on Baytex; and the circumstances in which we would be eligible to terminate our reporting obligations under the Securities Exchange Act of 1934, as amended.

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); availability and cost of gathering, processing and pipeline systems; failure to comply with the covenants in our debt agreements; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; risks associated with a third-party operating our Eagle Ford properties; the cost of developing and operating our assets; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; 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, 2020, 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, 2021	As at December 31, 2020
ASSETS			
Current assets			
Cash		**$ 1,375**	$ —
Trade and other receivables		**165,185**	107,477
Financial derivatives	16	**6,469**	5,057
		173,029	112,534
Non-current assets			
Exploration and evaluation assets	4	**181,563**	191,865
Oil and gas properties	5	**4,066,595**	3,077,548
Other plant and equipment		**7,733**	7,996
Lease assets		**9,242**	11,098
Deferred income tax asset	13	**—**	7,055
		$ 4,438,162	$ 3,408,096
LIABILITIES			
Current liabilities			
Trade and other payables		**$ 200,355**	$ 155,955
Financial derivatives	16	**186,922**	26,792
Lease obligations		**4,105**	4,289
Asset retirement obligations	8	**11,751**	11,820
		403,133	198,856
Non-current liabilities			
Financial derivatives	16	**11,749**	—
Credit facilities	6	**485,005**	649,221
Long-term notes	7	**1,095,775**	1,132,868
Lease obligations		**5,017**	6,787
Asset retirement obligations	8	**699,344**	748,563
Deferred income tax liability	13	**146,335**	93,588
		2,846,358	2,829,883
SHAREHOLDERS' EQUITY			
Shareholders' capital	9	**5,736,518**	5,729,418
Contributed surplus		**10,395**	14,345
Accumulated other comprehensive income		**611,770**	618,976
Deficit		**(4,766,879)**	(5,784,526)
		1,591,804	578,213
		$ 4,438,162	$ 3,408,096

Subsequent event (note 7)

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated Interim Statements of Income (Loss) and Comprehensive Income (Loss)
(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	**2021**	2020	**2021**	2020
Revenue, net of royalties					
Petroleum and natural gas sales	12	**$ 442,354**	$ 152,689	**$ 827,056**	$ 489,303
Royalties		**(81,531)**	(29,156)	**(148,481)**	(85,876)
		360,823	123,533	**678,575**	403,427
Expenses					
Operating		**82,901**	73,680	**163,449**	178,150
Transportation		**7,486**	5,031	**16,274**	15,373
Blending and other		**19,967**	5,460	**37,087**	26,817
General and administrative		**10,610**	7,438	**19,343**	17,213
Exploration and evaluation	4	**3,005**	1,831	**3,952**	2,091
Depletion and depreciation		**103,055**	104,540	**205,067**	285,926
Impairment (reversal) loss	4, 5	**(1,126,414)**	—	**(1,126,414)**	2,716,349
Share-based compensation	10	**2,770**	2,993	**5,751**	5,776
Financing and interest	14	**27,354**	30,230	**54,804**	69,450
Financial derivatives loss (gain)	16	**123,507**	55,662	**230,259**	(67,183)
Foreign exchange (gain) loss	15	**(2,256)**	(45,973)	**(5,061)**	53,919
Gain on dispositions		**(274)**	(11)	**(3,980)**	(148)
Other (income) expense		**(506)**	24	**(1,726)**	(2,007)
		(748,795)	240,905	**(401,195)**	3,301,726
Net income (loss) before income taxes		**1,109,618**	(117,372)	**1,079,770**	(2,898,299)
Income tax expense (recovery)	13				
Current income tax expense		**568**	89	**408**	558
Deferred income tax expense (recovery)		**56,051**	21,002	**61,715**	(262,177)
		56,619	21,091	**62,123**	(261,619)
Net income (loss)		**$ 1,052,999**	$ (138,463)	**$ 1,017,647**	$ (2,636,680)
Other comprehensive income (loss)					
Foreign currency translation adjustment		**(107)**	(53,452)	**(7,206)**	120,487
Comprehensive income (loss)		**$ 1,052,892**	$ (191,915)	**$ 1,010,441**	$ (2,516,193)
Net income (loss) per common share	11				
Basic		**$ 1.87**	$ (0.25)	**$ 1.81**	$ (4.71)
Diluted		**$ 1.85**	$ (0.25)	**$ 1.79**	$ (4.71)
Weighted average common shares (000's)	11				
Basic		**564,156**	560,512	**563,126**	560,158
Diluted		**569,931**	560,512	**568,115**	560,158

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, 2019		$ 5,718,835	$ 17,712	$ 556,224	$ (3,345,562)	**$ 2,947,209**
Vesting of share awards		7,873	(7,873)	—	—	**—**
Share-based compensation		—	4,637	—	—	**4,637**
Comprehensive income (loss)		—	—	120,487	(2,636,680)	**(2,516,193)**
Balance at June 30, 2020		$ 5,726,708	$ 14,476	$ 676,711	$ (5,982,242)	**$ 435,653**
Balance at December 31, 2020		$ 5,729,418	$ 14,345	$ 618,976	$ (5,784,526)	**$ 578,213**
Vesting of share awards	9	7,100	(7,100)	—	—	**—**
Share-based compensation	10	—	3,150	—	—	**3,150**
Comprehensive (loss) income		—	—	(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**

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	**2021**	2020	**2021**	2020
CASH PROVIDED BY (USED IN):					
Operating activities					
Net income (loss) for the period		**$ 1,052,999**	$ (138,463)	**$ 1,017,647**	$ (2,636,680)
Adjustments for:					
Non-cash share-based compensation	10	**1,646**	2,375	**3,150**	4,637
Unrealized foreign exchange (gain) loss	15	**(1,792)**	(45,516)	**(4,322)**	54,005
Exploration and evaluation	4	**3,005**	1,831	**3,952**	2,091
Depletion and depreciation		**103,055**	104,540	**205,067**	285,926
Impairment (reversal) loss	4, 5	**(1,126,414)**	—	**(1,126,414)**	2,716,349
Non-cash financing, accretion, and early redemption expense	14	**3,800**	2,843	**6,847**	13,528
Non-cash other income	8	**(676)**	—	**(1,664)**	—
Unrealized financial derivatives loss (gain)	16	**84,483**	69,286	**170,467**	(26,709)
Gain on dispositions		**(274)**	(11)	**(3,980)**	(148)
Deferred income tax expense (recovery)	13	**56,051**	21,002	**61,715**	(262,177)
Asset retirement obligations settled	8	**(993)**	(628)	**(2,410)**	(4,869)
Change in non-cash working capital		**(3,014)**	8,565	**(37,199)**	62,438
		171,876	25,824	**292,856**	208,391
Financing activities					
Increase (decrease) in credit facilities		**(117,939)**	31,426	**(160,660)**	187,347
Payments on lease obligations		**(919)**	(1,468)	**(2,001)**	(2,984)
Net proceeds from issuance of long-term notes		**—**	—	**—**	652,150
Redemption of long-term notes	7	**(6,787)**	—	**(6,787)**	(833,672)
		(125,645)	29,958	**(169,448)**	2,841
Investing activities					
Additions to exploration and evaluation assets	4	**(428)**	(72)	**(644)**	(3,860)
Additions to oil and gas properties	5	**(61,057)**	(9,780)	**(144,429)**	(182,769)
Additions to other plant and equipment		**(320)**	(1,375)	**(411)**	(1,987)
Property acquisitions		**—**	—	**(25)**	—
Proceeds from dispositions		**18**	11	**246**	51
Change in non-cash working capital		**16,931**	(44,566)	**23,230**	(28,239)
		(44,856)	(55,782)	**(122,033)**	(216,804)
Change in cash		**1,375**	—	**1,375**	(5,572)
Cash, beginning of period		**—**	—	**—**	5,572
Cash, end of period		**$ 1,375**	$ —	**$ 1,375**	$ —
Supplementary information					
Interest paid		**$ 16,764**	$ 29,183	**$ 47,601**	$ 51,780
Income taxes paid		**$ —**	$ —	**$ —**	$ —

See accompanying notes to the condensed consolidated interim financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the “Company” or “Baytex”) is an oil and gas corporation 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, 2020.

The consolidated financial statements were approved by the Board of Directors of Baytex on July 28, 2021.

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, 2020 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 2020 annual financial statements have been applied in the preparation of these consolidated financial statements.

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, 2021, the global economy continued to show signs of recovery from the impacts of the COVID-19 pandemic. The outlook for crude oil demand has improved due to the easing of restrictions combined with the distribution of vaccines in developed countries. Global spot prices for crude oil have recovered to pre-pandemic levels as optimism for demand recovery improves and have also been supported by limited production growth from independent producers. While we have benefited from these recent improvements in crude oil prices there is a degree of uncertainty related to COVID-19 that has been considered in our estimates for the period ended June 30, 2021.

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	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 254,026**	$ 73,325	**$ 188,328**	$ 79,364	**$ —**	$ —	**$ 442,354**	$ 152,689
Royalties	**(26,193)**	(6,157)	**(55,338)**	(22,999)	**—**	—	**(81,531)**	(29,156)
	227,833	67,168	**132,990**	56,365	**—**	—	**360,823**	123,533
Expenses								
Operating	**61,793**	49,162	**21,108**	24,518	**—**	—	**82,901**	73,680
Transportation	**7,486**	5,031	**—**	—	**—**	—	**7,486**	5,031
Blending and other	**19,967**	5,460	**—**	—	**—**	—	**19,967**	5,460
General and administrative	**—**	—	**—**	—	**10,610**	7,438	**10,610**	7,438
Exploration and evaluation	**3,005**	1,831	**—**	—	**—**	—	**3,005**	1,831
Depletion and depreciation	**63,088**	57,650	**38,663**	44,972	**1,304**	1,918	**103,055**	104,540
Impairment reversal	**(684,000)**	—	**(442,414)**	—	**—**	—	**(1,126,414)**	—
Share-based compensation	**—**	—	**—**	—	**2,770**	2,993	**2,770**	2,993
Financing and interest	**—**	—	**—**	—	**27,354**	30,230	**27,354**	30,230
Financial derivatives loss	**—**	—	**—**	—	**123,507**	55,662	**123,507**	55,662
Foreign exchange gain	**—**	—	**—**	—	**(2,256)**	(45,973)	**(2,256)**	(45,973)
Gain on dispositions	**(274)**	(11)	**—**	—	**—**	—	**(274)**	(11)
Other income	**(676)**	—	**—**	—	**170**	24	**(506)**	24
	(529,611)	119,123	**(382,643)**	69,490	**163,459**	52,292	**(748,795)**	240,905
Net income (loss) before income taxes	**757,444**	(51,955)	**515,633**	(13,125)	**(163,459)**	(52,292)	**1,109,618**	(117,372)
Income tax expense (recovery)								
Current income tax expense	**—**	—	**568**	89	**—**	—	**568**	89
Deferred income tax expense (recovery)	**60,556**	6,421	**48,996**	21,002	**(53,501)**	(6,421)	**56,051**	21,002
	60,556	6,421	**49,564**	21,091	**(53,501)**	(6,421)	**56,619**	21,091
Net income (loss)	**$ 696,888**	$ (58,376)	**$ 466,069**	$ (34,216)	**$ (109,958)**	$ (45,871)	**$ 1,052,999**	$ (138,463)
Total oil and natural gas capital expenditures [1]	**$ 30,369**	$ 2,918	**$ 31,098**	$ 6,923	**$ —**	$ —	**$ 61,467**	$ 9,841

	Canada		U.S.		Corporate		Consolidated	
Six Months Ended June 30	**2021**	2020	**2021**	2020	**2021**	2020	**2021**	2020
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 493,448**	$ 268,169	**$ 333,608**	$ 221,134	**$ —**	$ —	**$ 827,056**	$ 489,303
Royalties	**(50,857)**	(21,675)	**(97,624)**	(64,201)	**—**	—	**(148,481)**	(85,876)
	442,591	246,494	**235,984**	156,933	**—**	—	**678,575**	403,427
Expenses								
Operating	**123,154**	128,084	**40,295**	50,066	**—**	—	**163,449**	178,150
Transportation	**16,274**	15,373	**—**	—	**—**	—	**16,274**	15,373
Blending and other	**37,087**	26,817	**—**	—	**—**	—	**37,087**	26,817
General and administrative	**—**	—	**—**	—	**19,343**	17,213	**19,343**	17,213
Exploration and evaluation	**3,952**	2,091	**—**	—	**—**	—	**3,952**	2,091
Depletion and depreciation	**133,562**	180,398	**68,928**	101,642	**2,577**	3,886	**205,067**	285,926
Impairment (reversal) loss	**(684,000)**	1,855,000	**(442,414)**	861,349		—	**(1,126,414)**	2,716,349
Share-based compensation	**—**	—	**—**	—	**5,751**	5,776	**5,751**	5,776
Financing and interest	**—**	—	**—**	—	**54,804**	69,450	**54,804**	69,450
Financial derivatives loss (gain)	**—**	—	**—**	—	**230,259**	(67,183)	**230,259**	(67,183)
Foreign exchange (gain) loss	**—**	—	**—**	—	**(5,061)**	53,919	**(5,061)**	53,919
Gain on dispositions	**(3,980)**	(148)	**—**	—	**—**	—	**(3,980)**	(148)
Other income	**(1,664)**	—	**—**	—	**(62)**	(2,007)	**(1,726)**	(2,007)
	(375,615)	2,207,615	**(333,191)**	1,013,057	**307,611**	81,054	**(401,195)**	3,301,726
	818,206	(1,961,121)	**569,175**	(856,124)	**(307,611)**	(81,054)	**1,079,770**	(2,898,299)
Income tax expense (recovery)								
Current income tax (recovery) expense	**(296)**	469	**704**	89	**—**	—	**408**	558
Deferred income tax expense (recovery)	**68,976**	(85,276)	**54,660**	(164,994)	**(61,921)**	(11,907)	**61,715**	(262,177)
	68,680	(84,807)	**55,364**	(164,905)	**(61,921)**	(11,907)	**62,123**	(261,619)
Net income (loss)	**$ 749,526**	$ (1,876,314)	**$ 513,811**	$ (691,219)	**$ (245,690)**	$ (69,147)	**$ 1,017,647**	$ (2,636,680)
Total oil and natural gas capital expenditures [(1)]	**$ 72,669**	$ 125,989	**$ 72,183**	$ 60,589	**$ —**	$ —	**$ 144,852**	$ 186,578

(1) Includes additions to exploration and evaluation assets, oil and gas properties, and property acquisitions, net of proceeds from divestitures.

	June 30, 2021	December 31, 2020
Canadian assets	**$ 2,251,609**	$ 1,646,412
U.S. assets	**2,163,109**	1,737,533
Corporate assets	**23,444**	24,151
Total consolidated assets	**$ 4,438,162**	$ 3,408,096

4. EXPLORATION AND EVALUATION ASSETS

		June 30, 2021		December 31, 2020
Balance, beginning of period	**$**	**191,865**	$	320,210
Capital expenditures		**644**		4,490
Property swaps		**(78)**		468
Impairment		**—**		(113,058)
Exploration and evaluation expense		**(3,952)**		(14,011)
Transfer to oil and gas properties (note 5)		**(4,434)**		(8,585)
Foreign currency translation		**(2,482)**		2,351
Balance, end of period	**$**	**181,563**	$	191,865

At June 30, 2021, there were no indicators of impairment or impairment reversal for exploration and evaluation assets in any of the Company's CGUs.

At March 31, 2020, the Company identified indicators of impairment for the exploration and evaluation assets within each of its six CGUs. The estimated recoverable amount was below the carrying value of the exploration and evaluation assets in the Conventional, Peace River, Lloydminster, Viking, and Eagle Ford CGUs and an impairment loss of $127.9 million was recorded at March 31, 2020. The recoverable amount of each CGU was based on its fair value less costs of disposal ("FVLCD") and was estimated with reference to arm's length transactions in comparable locations and the discounted cash flows associated with the Company's future development plans. The following table indicates the impairment loss booked for each CGU at March 31, 2020.

		Impairment loss at March 31, 2020
Conventional CGU	$	4,000
Peace River CGU		20,000
Lloydminster CGU		42,000
Viking CGU		13,000
Eagle Ford CGU		48,861
	$	127,861

At December 31, 2020, the Company estimated the recoverable amount of the exploration and evaluation assets within each of its six CGUs due to the ongoing volatility in future oil and natural gas prices. The recoverable amount supported the carrying amount for the Conventional, Peace River, Lloydminster, and Duvernay CGUs and no impairment loss or impairment reversal was recorded. The recoverable amount for the Viking and Eagle Ford CGUs exceeded their carrying amounts which resulted in an impairment reversal of $14.8 million at December 31, 2020. The recoverable amount of each CGU was based on its FVLCD and was estimated with reference to arm's length transaction in comparable locations and the discounted cash flows associated with the Company's future development plans. The following table indicates the impairment reversal booked for the Viking and Eagle Ford CGUs at December 31, 2020.

		Impairment Reversal at December 31, 2020
Viking CGU	$	2,000
Eagle Ford CGU		12,803
	$	14,803

5. OIL AND GAS PROPERTIES

		Cost		Accumulated depletion		Net book value
Balance, December 31, 2019	**$**	**11,128,297**	**$**	**(5,740,408)**	**$**	**5,387,889**
Capital expenditures		275,850		—		275,850
Transfers from exploration and evaluation assets (note 4)		8,585		—		8,585
Change in asset retirement obligations (note 8)		94,994		—		94,994
Property swaps		(1,190)		178		(1,012)
Impairment		—		(2,247,162)		(2,247,162)
Foreign currency translation		(82,860)		120,123		37,263
Depletion		—		(478,859)		(478,859)
Balance, December 31, 2020	**$**	**11,423,676**	**$**	**(8,346,128)**	**$**	**3,077,548**
Capital expenditures		144,429		—		144,429
Property acquisitions		156		—		156
Transfers from exploration and evaluation assets (note 4)		4,434		—		4,434
Change in asset retirement obligations (note 8)		(46,165)		—		(46,165)
Property swaps		(21,283)		21,312		29
Impairment reversal		—		1,126,414		1,126,414
Foreign currency translation		(114,516)		76,756		(37,760)
Depletion		—		(202,490)		(202,490)
Balance, June 30, 2021	**$**	**11,390,731**	**$**	**(7,324,136)**	**$**	**4,066,595**

Baytex recorded an impairment reversal of $1.1 billion for its oil and gas properties at June 30, 2021 and a net impairment loss of $2.2 billion for the year ended December 31, 2020.

At June 30, 2021, we identified indicators of impairment reversal for oil and gas properties in each of our six CGU's 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 and 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 June 30, 2021, the recoverable amount of the Company's CGUs were calculated using the following benchmark reference prices for the years 2021 to 2030 adjusted for commodity differentials specific to the Company. The prices and costs subsequent to 2030 have been adjusted for inflation at an annual rate of 2.0%.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
WTI crude oil (US$/bbl)	71.33	67.20	63.95	63.23	64.50	65.79	67.10	68.44	69.81	71.21
WCS heavy oil (CA$/bbl)	72.22	66.84	61.73	60.70	61.91	63.15	64.42	65.70	67.02	68.36
LLS crude oil (US$/bbl)	72.17	68.53	65.80	65.10	66.39	67.71	69.05	70.42	71.82	73.26
Edmonton par oil (CA$/bbl)	83.20	78.27	74.06	73.05	74.51	76.00	77.52	79.07	80.66	82.27
Henry Hub gas (US$/mmbtu)	3.42	3.19	2.92	2.96	3.02	3.08	3.14	3.21	3.27	3.34
AECO gas (CA$/mmbtu)	3.46	3.13	2.72	2.71	2.76	2.82	2.88	2.94	2.99	3.05
Exchange rate (CAD/USD)	1.24	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25	1.25

The following table summarizes the recoverable amount and impairment reversal at June 30, 2021 and demonstrates the sensitivity of the estimated recoverable amount of the Company's CGUs comprising oil and gas properties to reasonably possible changes in key assumptions inherent in the estimate.

	Recoverable amount	Impairment reversal	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU	$ 57,891	$ 15,000	$ 1,000	$ 1,000	$ 8,000
Peace River CGU	238,714	154,000	4,000	40,000	2,500
Lloydminster CGU	340,730	154,000	12,500	52,000	—
Duvernay CGU (1)	115,157	5,000	45,000	44,500	44,500
Viking CGU	1,338,985	356,000	47,000	89,500	4,500
Eagle Ford CGU	2,015,118	442,415	109,400	103,900	24,400
	$ 4,106,595	$ 1,126,415	$ 218,900	$ 330,900	$ 83,900

(1) The impairment reversal for the Duvernay CGU was limited to total accumulated impairments less subsequent depletion of $5.0 million.

At March 31, 2020, the Company identified indicators of impairment for each of its six CGUs due to a significant decline in forecasted commodity prices. The recoverable amount was not sufficient to support the carrying amount which resulted in an impairment of $2.6 billion recorded at March 31, 2020. The recoverable amount of 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, 2019 and was adjusted for operations between December 31, 2019 and March 31, 2020. The after-tax discount rates applied to the cash flows were between 8% and 14%.

The recoverable amount of the Company's CGUs were calculated at March 31, 2020 using the following benchmark reference prices for the years 2020 to 2029 adjusted for commodity differentials specific to the Company. The prices and costs subsequent to 2029 have been adjusted for inflation at an annual rate of 2%.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
WTI crude oil (US$/bbl)	29.17	40.45	49.17	53.28	55.66	56.87	58.01	59.17	60.35	61.56
WCS heavy oil (CA$/bbl)	19.21	34.65	46.34	51.25	54.28	55.72	56.96	58.22	59.51	60.82
LLS crude oil (US$/bbl)	32.17	43.80	52.55	56.68	59.10	60.35	61.52	62.72	63.94	65.19
Edmonton par oil (CA$/bbl)	29.22	46.85	59.27	65.02	68.43	69.81	71.24	72.70	74.19	75.71
Henry Hub gas (US$/mmbtu)	2.10	2.58	2.79	2.86	2.93	3.00	3.07	3.13	3.19	3.25
AECO gas (CA$/mmbtu)	1.74	2.20	2.38	2.45	2.53	2.60	2.66	2.72	2.79	2.85
Exchange rate (CAD/USD)	1.41	1.37	1.34	1.34	1.34	1.33	1.33	1.33	1.33	1.33

The following table demonstrates the sensitivity of the estimated recoverable amount of the Company's CGUs to reasonably possible changes in key assumptions inherent in the estimate.

	Recoverable amount	Impairment loss	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU	$ 37,444	$ 41,000	$ 3,000	$ 3,500	$ 8,500
Peace River CGU	109,631	345,000	9,500	53,500	3,000
Lloydminster CGU	227,967	470,000	25,000	69,500	—
Duvernay CGU	61,197	5,000	5,500	9,500	1,500
Viking CGU	962,134	915,000	57,000	123,000	4,000
Eagle Ford CGU	1,576,423	812,488	120,750	141,500	32,000
	$ 2,974,796	$ 2,588,488	$ 220,750	$ 400,500	$ 49,000

At December 31, 2020, the Company estimated the recoverable amount of each of its six CGUs due to the volatility in commodity prices during the year and a reduction in future development costs per well for the Viking and Eagle Ford CGUs. The recoverable amount supported the carrying amount for the Conventional, Peace River, Lloydminster, and Duvernay CGUs and no impairment or impairment reversal was recorded. The recoverable amount for the Viking and Eagle Ford CGUs exceeded their carrying amounts which resulted in an impairment reversal of $341.3 million recorded at December 31, 2020. 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. The after-tax discount rates applied to the cash flows were between 10% and 17%.

The recoverable amount of the Company's CGUs were calculated at December 31, 2020 using the following benchmark reference prices for the years 2021 to 2030 adjusted for commodity differentials specific to the Company. The prices and costs subsequent to 2030 have been adjusted for inflation at an annual rate of 2%.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
WTI crude oil (US$/bbl)	47.17	50.17	53.17	54.97	56.07	57.19	58.34	59.50	60.69	61.91
WCS heavy oil (CA$/bbl)	44.63	48.18	52.10	54.10	55.19	56.29	57.42	58.57	59.74	60.93
LLS crude oil (US$/bbl)	49.50	52.85	55.87	57.69	58.82	59.97	61.15	62.34	63.56	64.83
Edmonton par oil (CA$/bbl)	55.76	59.89	63.48	65.76	67.13	68.53	69.95	71.40	72.88	74.34
Henry Hub gas (US$/mmbtu)	2.83	2.87	2.90	2.96	3.02	3.08	3.14	3.20	3.26	3.33
AECO gas (CA$/mmbtu)	2.78	2.70	2.61	2.65	2.70	2.76	2.81	2.87	2.92	2.98
Exchange rate (CAD/USD)	1.30	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31

The following table demonstrates the sensitivity of the estimated recoverable amount of the Company's CGUs to reasonably possible changes in key assumptions inherent in the estimate.

	Recoverable amount	Impairment reversal	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU	$ 54,265	$ —	$ 1,000	$ 3,000	$ 9,000
Peace River CGU	104,225	—	1,000	49,500	3,000
Lloydminster CGU	212,979	—	7,000	57,500	500
Duvernay CGU	70,491	—	5,500	12,000	1,500
Viking CGU	1,026,026	116,000	34,500	106,500	5,000
Eagle Ford CGU	1,609,562	225,326	91,600	157,500	38,400
	$ 3,077,548	$ 341,326	$ 140,600	$ 386,000	$ 57,400

6. CREDIT FACILITIES

	June 30, 2021	December 31, 2020
Credit facilities - U.S. dollar denominated (1)	**$ 140,419**	$ 140,815
Credit facilities - Canadian dollar denominated	**346,204**	510,358
Credit facilities - principal	**486,623**	651,173
Unamortized debt issuance costs	**(1,618)**	(1,952)
Credit facilities	**$ 485,005**	$ 649,221

(1) U.S. dollar denominated credit facilities balance was US$113.2 million as at June 30, 2021 (December 31, 2020 - US$110.4 million).

Baytex has US$575 million of revolving credit facilities (the "Revolving Facilities") and a $300 million non-revolving secured term loan (the "Term Loan") (collectively the "Credit Facilities"). The Credit Facilities mature on April 2, 2024 and will automatically be extended to June 4, 2024 providing Baytex has either refinanced, or has the ability to repay, the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.

The extendible secured Revolving Facilities are comprised of a US$50 million operating loan and a US$325 million syndicated revolving loan for Baytex and a US$200 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. The $300 million Term Loan is secured by the assets of Baytex's wholly-owned subsidiary, Baytex Energy Limited Partnership.

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 Baytex's 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 London Interbank Offered Rates ("LIBOR"), plus applicable margins.

The LIBOR benchmark transition begins on December 31, 2021. Certain tenors of the U.S. dollar LIBOR benchmark will no longer be published as of December 31, 2021 while some tenors will continue to be published through mid-2023. We expect the U.S. dollar LIBOR benchmarks to be replaced with an alternative that will apply to our U.S. dollar borrowing at our option. We do not expect this change to have a material impact to Baytex as U.S. dollar borrowings under the credit facilities can also bear interest at the U.S. base loan rate.

At June 30, 2021, Baytex had $14.7 million of outstanding letters of credit (December 31, 2020 - $15.0 million) under the Credit Facilities.

At June 30, 2021, Baytex was in compliance with all of the covenants contained in the Credit Facilities and is forecasting compliance with these covenants based on current forward commodity prices. The following table summarizes the financial covenants applicable to the Credit Facilities and Baytex's compliance therewith as at June 30, 2021.

Covenant Description	Position as at June 30, 2021	Covenant
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**0.8:1.0**	**3.5:1.0**
Interest Coverage (3) (Minimum Ratio)	**6.0:1.0**	**2.0:1.0**

(1) "Senior Secured Debt" is defined as the principal amount of the credit facilities and other secured obligations identified in the credit agreement. As at June 30, 2021, the Company's Senior Secured Debt totaled $501.4 million which included $486.6 million of principal amounts outstanding and $14.7 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 expense, income tax, non-recurring losses, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expense, impairment, deferred income tax expense or recovery, unrealized gains and losses on financial derivatives and foreign exchange, and share-based compensation) 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, 2021 was $592.2 million.

(3) "Interest Coverage" is computed as the ratio of Bank EBITDA to financing and interest expense, excluding accretion of debt issue costs and asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expense, excluding accretion of debt issue costs and asset retirement obligations, for the twelve months ended June 30, 2021 was $98.3 million.

7. LONG-TERM NOTES

	June 30, 2021	December 31, 2020
5.625% notes (US$394,200 – principal) due June 1, 2024	**$ 488,986**	$ 510,200
8.75% notes (US$500,000 – principal) due April 1, 2027	**620,225**	637,750
Total long-term notes - principal (1)	**1,109,211**	1,147,950
Unamortized debt issuance costs	**(13,436)**	(15,082)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,095,775**	$ 1,132,868

(1) The decrease in the principal amount of long-term notes outstanding from December 31, 2020 to June 30, 2021 is the result of principal repayments of $7.1 million and changes in the reported amount of U.S. denominated debt of $31.6 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.

During the three months ended June 30, 2021, we redeemed and cancelled US$5.8 million principal of the 5.625% Notes at a discount and recorded a gain of $0.4 million. Subsequent to June 30, 2021, we amended the 2014 note indenture to expand our permitted secured indebtedness to align these amounts with the 2020 indenture. We also used free cash flow generated in the first half of 2021 to repurchase and cancel US$100.0 million principal amount of the 5.625% Notes due 2024 at the call price of 100.938%, plus accrued interest, effective July 28, 2021.

8. ASSET RETIREMENT OBLIGATIONS

		June 30, 2021		December 31, 2020
Balance, beginning of period	**$**	**760,383**	$	667,974
Liabilities incurred		**6,609**		15,189
Liabilities settled		**(2,410)**		(7,168)
Liabilities acquired from property acquisitions		**131**		—
Liabilities divested		**(257)**		(721)
Property swaps		**(3,526)**		(525)
Accretion (note 14)		**5,665**		8,978
Government grants (1)		**(1,664)**		(2,128)
Change in estimate		**(323)**		(12,771)
Changes in discount rates and inflation rates (2)		**(52,451)**		92,576
Foreign currency translation		**(1,062)**		(1,021)
Balance, end of period	**$**	**711,095**	$	760,383
Less current portion of asset retirement obligations		**11,751**		11,820
Non-current portion of asset retirement obligations	**$**	**699,344**	$	748,563

(1) During the six months ended June 30, 2021, Baytex recognized $1.7 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 ($2.1 million for the year ended December 31, 2020).

(2) The discount and inflation rates at June 30, 2021 were 1.8% and 1.7%, respectively, compared to 1.2% and 1.5% at December 31, 2020.

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, 2021, 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.

	Number of Common Shares (000s)		Amount
Balance, December 31, 2019	**558,305**	**$**	**5,718,835**
Vesting of share awards	2,922		10,583
Balance, December 31, 2020	**561,227**	**$**	**5,729,418**
Vesting of share awards	2,955		7,100
Balance, June 30, 2021	**564,182**	**$**	**5,736,518**

10. SHARE AWARD INCENTIVE PLAN

For the three and six months ended June 30, 2021 the Company recorded total compensation expense related to the share awards of $2.8 million and $5.8 million respectively ($3.0 million and $5.8 million for the three and six months ended June 30, 2020). Included in compensation expense related to share awards for the three and six months ended June 30, 2021 is $1.1 million and $2.6 million of cash compensation expense related to the incentive award plan, deferred share unit plan and the associated equity total return swaps ($0.6 million and $1.1 million for the three and six months ended June 30, 2020).

Share Award Plans

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.

The weighted average fair value of share awards granted was $1.29 per restricted and performance award for the six months ended June 30, 2021 ($1.48 per restricted and performance award for the six months ended June 30, 2020).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards(1)	Total number of share awards
Balance, December 31, 2019	**3,801**	**3,135**	**6,936**
Granted	2,239	3,253	5,492
Vested and converted to common shares	(1,730)	(1,192)	(2,922)
Forfeited	(188)	(1,108)	(1,296)
Balance, December 31, 2020	**4,122**	**4,088**	**8,210**
Granted	—	4,023	4,023
Vested and converted to common shares	(1,839)	(1,143)	(2,982)
Forfeited	(103)	(66)	(169)
Balance, June 30, 2021	**2,180**	**6,902**	**9,082**

(1) Based on underlying awards before applying the payout multiplier which can range from 0x to 2x.

Incentive Award Plan

Baytex has a cash-settled 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, 2021, Baytex granted 4.9 million awards under the Incentive Award plan at a fair value of $1.29 per award (2.9 million awards granted at a fair value of $1.50 per incentive award for the six months ended June 30, 2020). At June 30, 2021 there were 6.5 million awards outstanding under the Incentive Award plan.

Deferred Share Unit Plan

Baytex has a deferred share unit plant (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, 2021, Baytex granted 0.9 million awards under the DSU plan at a fair value of $1.29 per award. At June 30, 2021, there were 0.8 million awards outstanding under the DSU plan.

The Company uses equity total return swaps on the equivalent number of Baytex common shares in order to fix the aggregate cost of the Incentive Award plan and the DSU plan at the fair value determined on the grant date. The carrying value of the financial derivatives includes the unrealized fair value of the equity total return swaps which was an asset of $4.2 million at June 30, 2021 (December 31, 2020 - liability of $1.1 million).

11. NET LOSS 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 or loss per share amounts reflect the potential dilution that could occur if share awards and share options were converted to common shares. The treasury stock method is used to determine the dilutive effect of share awards and share options whereby the potential conversion of share awards and share options 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								
	2021				2020				
	Net income	**Weighted average common shares (000s)**		**Net income per share**		Net loss	Weighted average common shares (000s)		Net loss per share
Net income (loss) - basic	**$ 1,052,999**	**564,156**	**$**	**1.87**	$	(138,463)	560,512	$	(0.25)
Dilutive effect of share awards	**—**	**5,775**		**—**		—	—		—
Net income (loss) - diluted	**$ 1,052,999**	**569,931**	**$**	**1.85**	$	(138,463)	560,512	$	(0.25)

	Six Months Ended June 30								
	2021				2020				
	Net income	**Weighted average common shares (000s)**		**Net income per share**		Net loss	Weighted average common shares (000s)		Net loss per share
Net income (loss) - basic	**$ 1,017,647**	**563,126**	**$**	**1.81**	$	(2,636,680)	560,158	$	(4.71)
Dilutive effect of share awards	**—**	**4,989**		**—**		—	—		—
Net income (loss) - diluted	**$ 1,017,647**	**568,115**	**$**	**1.79**	$	(2,636,680)	560,158	$	(4.71)

For the three and six months ended June 30, 2021, no share awards were excluded from the calculation of diluted income per share as their effect was dilutive. For the three and six months ended June 30, 2020, all share awards were excluded from the calculation of diluted loss per share as their effect was anti-dilutive given the Company recorded a net loss.

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					
	2021			2020		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 106,269**	**$ 158,390**	**$ 264,659**	$ 42,231	$ 61,043	$ 103,274
Heavy oil	**129,782**	**—**	**129,782**	24,003	—	24,003
NGL	**3,786**	**16,796**	**20,582**	847	8,035	8,882
Natural gas sales	**14,189**	**13,142**	**27,331**	6,244	10,286	16,530
Total petroleum and natural gas sales	**$ 254,026**	**$ 188,328**	**$ 442,354**	$ 73,325	$ 79,364	$ 152,689

	Six Months Ended June 30					
	2021			2020		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 217,814**	**$ 263,986**	**$ 481,800**	$ 151,314	$ 182,198	$ 333,512
Heavy oil	**238,820**	**—**	**238,820**	99,846	—	99,846
NGL	**8,150**	**29,939**	**38,089**	2,196	16,877	19,073
Natural gas sales	**28,664**	**39,683**	**68,347**	14,813	22,059	36,872
Total petroleum and natural gas sales	**$ 493,448**	**$ 333,608**	**$ 827,056**	$ 268,169	$ 221,134	$ 489,303

Included in accounts receivable at June 30, 2021 is $145.1 million of accrued production revenue related to delivered volumes (December 31, 2020 - $81.3 million).

13. INCOME TAXES

The provision for income taxes has been computed as follows:

	Six Months Ended June 30	
	2021	2020
Net income (loss) before income taxes	**$ 1,079,770**	$ (2,898,299)
Expected income taxes at the statutory rate of 24.89% (2020 – 25.89%)	**268,755**	(750,370)
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	**784**	1,200
Effect of foreign exchange	**(656)**	6,968
Effect of change in income tax rates	**—**	22,269
Effect of rate adjustments for foreign jurisdictions	**(17,339)**	36,097
Effect of change in deferred tax benefit not recognized	**(191,235)**	400,423
Effect of U.S. tax change	**—**	20,160
Adjustments and assessments	**1,814**	1,634
Income tax expense (recovery)	**$ 62,123**	$ (261,619)

At June 30, 2021, a deferred tax asset of $277.1 million remains unrecognized due to uncertainty surrounding future commodity prices and future capital gains (December 31, 2020 - $469.7 million).

As disclosed in the 2020 annual financial statements, in June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the "CRA") that denied $591 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	
	2021	2020	**2021**	2020
Interest on credit facilities	**$ 3,250**	$ 4,248	**$ 6,586**	$ 8,383
Interest on long-term notes	**20,246**	23,015	**41,253**	47,288
Interest on lease obligations	**58**	124	**118**	251
Non-cash financing	**790**	665	**1,539**	5,107
Accretion on asset retirement obligations (note 8)	**3,367**	2,178	**5,665**	5,109
Gain on redemption of long-term notes (note 7)	**(357)**	—	**(357)**	—
Early redemption expense	**—**	—	**—**	3,312
Financing and interest	**$ 27,354**	$ 30,230	**$ 54,804**	$ 69,450

15. FOREIGN EXCHANGE

	Three Months Ended June 30		Six Months Ended June 30	
	2021	2020	**2021**	2020
Unrealized foreign exchange loss - intercompany notes (1)	**$ 12,579**	$ —	**$ 26,320**	$ —
Unrealized foreign exchange (gain) loss - long-term notes	**(14,371)**	(45,516)	**(30,642)**	54,005
Realized foreign exchange gain	**(464)**	(457)	**(739)**	(86)
Foreign exchange (gain) loss	**$ (2,256)**	$ (45,973)	**$ (5,061)**	$ 53,919

(1) During 2020, a series of intercompany notes totaling US$751.0 million were issued from a Canadian subsidiary to a U.S. subsidiary. These notes are eliminated upon consolidation within the Condensed Consolidated 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 subsidiary are recognized in unrealized foreign exchange gain or loss whereas those within the U.S. subsidiary 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 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, 2021		December 31, 2020		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial derivatives	**$ 6,469**	**$ 6,469**	$ 5,057	$ 5,057	Level 2
Total	**$ 6,469**	**$ 6,469**	$ 5,057	$ 5,057	
Financial assets at amortized cost					
Cash	**$ 1,375**	**$ 1,375**	$ —	$ —	—
Trade and other receivables	**165,185**	**165,185**	107,477	107,477	—
Total	**$ 166,560**	**$ 166,560**	$ 107,477	$ 107,477	
Financial Liabilities					
FVTPL					
Financial derivatives	**$ (198,671)**	**$ (198,671)**	$ (26,792)	$ (26,792)	Level 2
Total	**$ (198,671)**	**$ (198,671)**	$ (26,792)	$ (26,792)	
Financial liabilities at amortized cost					
Trade and other payables	**$ (200,355)**	**$ (200,355)**	$ (155,955)	$ (155,955)	—
Credit facilities	**(485,005)**	**(486,623)**	(649,221)	(651,173)	—
Long-term notes	**(1,095,775)**	**(1,120,203)**	(1,132,868)	(761,129)	Level 1
Total	**$ (1,781,135)**	**$ (1,807,181)**	$ (1,938,044)	$ (1,568,257)	

There were no transfers between Level 1 and Level 2 during the six months ended June 30, 2021 and 2020.

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, 2021	December 31, 2020	**June 30, 2021**	December 31, 2020
U.S. dollar denominated	**US$752,172**	US$759,508	**US$1,125,409**	US$934,731

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of July 28, 2021:

	Remaining Period	Volume	Price/Unit [1]	Index
Oil				
Basis Swap	Jul 2021 to Dec 2021	8,000 bbl/d	WTI less US$13.41/bbl	WCS
Basis Swap	Jan 2022 to Dec 2022	9,000 bbl/d	WTI less US$12.47/bbl	WCS
Basis Swap [4]	Jan 2022 to Dec 2022	1,000 bbl/d	WTI less US$13.00/bbl	WCS
Basis Swap	Jul 2021 to Dec 2021	7,500 bbl/d	WTI less US$5.03/bbl	MSW
Basis Swap	Jan 2022 to Dec 2022	1,000 bbl/d	WTI less US$4.75/bbl	MSW
Basis Swap [4]	Jan 2022 to Dec 2022	1,000 bbl/d	WTI less US$4.50/bbl	MSW
Fixed Sell	Jul 2021 to Dec 2021	4,000 bbl/d	US$45.00/bbl	WTI
3-way option [2]	Jul 2021 to Dec 2021	500 bbl/d	US$35.00/US$45.00/US$49.03	WTI
3-way option [2]	Jul 2021 to Dec 2021	1,500 bbl/d	US$35.00/US$45.00/US$49.10	WTI
3-way option [2]	Jul 2021 to Dec 2021	3,500 bbl/d	US$35.00/US$45.00/US$49.50	WTI
3-way option [2]	Jul 2021 to Dec 2021	10,000 bbl/d	US$35.00/US$45.00/US$55.00	WTI
3-way option [2]	Jul 2021 to Dec 2021	2,000 bbl/d	US$37.00/US$42.50/US$48.00	WTI
3-way option [2]	Jan 2022 to Dec 2022	1,500 bbl/d	US$40.00/US$50.00/US$58.10	WTI
3-way option [2]	Jan 2022 to Dec 2022	2,000 bbl/d	US$46.00/US$56.00/US$66.72	WTI
3-way option [2]	Jan 2022 to Dec 2022	2,500 bbl/d	US$47.00/US$57.00/US$67.00	WTI
3-way option [2]	Jan 2022 to Dec 2022	2,500 bbl/d	US$50.00/US$60.00/US$70.00	WTI
3-way option [2]	Jan 2022 to Dec 2022	2,000 bbl/d	US$53.00/US$63.50/US$72.90	WTI
Swaption [3]	Jan 2022 to Dec 2022	5,000 bbl/d	US$53.00/bbl	WTI
Swaption [3]	Jan 2022 to Dec 2022	5,000 bbl/d	US$54.00/bbl	WTI
Natural Gas				
Fixed Sell	Jul 2021 to Dec 2021	16,000 GJ/d	$2.36/GJ	AECO 7A
Fixed Sell	Jan 2022 to Dec 2022	5,000 GJ/d	$2.53/GJ	AECO 7A
Fixed Sell	Jul 2021 to Dec 2021	2,500 GJ/d	$2.40/GJ	AECO 5A
Fixed Sell	Jan 2022 to Dec 2022	6,250 GJ/d	$2.59/GJ	AECO 5A
Fixed Sell [4]	Jan 2022 to Dec 2022	6,000 GJ/d	$2.95/GJ	AECO 5A
Fixed Sell	Jul 2021 to Dec 2021	12,000 mmbtu/d	US$2.70/mmbtu	NYMEX
Fixed Sell	Jan 2022 to Dec 2022	1,000 mmbtu/d	US$2.94/mmbtu	NYMEX
3-way option [2]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.25/US$2.75/US$3.06	NYMEX
3-way option [2]	Jan 2022 to Dec 2022	1,500 mmbtu/d	US$2.60/US$2.91/US$3.56	NYMEX
3-way option [2]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.60/US$3.00/US$3.83	NYMEX
3-way option [2]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.65/US$2.90/US$3.40	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.

(3) For these contracts, the counterparty has the right, if exercised on December 31, 2021, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

(4) Contracts entered subsequent to June 30, 2021.

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	
	2021	2020	**2021**	2020
Realized financial derivatives loss (gain)	**$ 39,024**	$ (13,624)	**$ 59,792**	$ (40,474)
Unrealized financial derivatives loss (gain)	**84,483**	69,286	**170,467**	(26,709)
Financial derivatives loss (gain)	**$ 123,507**	$ 55,662	**$ 230,259**	$ (67,183)

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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Chair 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

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Executive Vice President and
Chief Financial Officer

Chad E. Lundberg
Chief Operating and
Sustainability Officer

Brian G. Ector
Vice President, Capital Markets

Kendall D. Arthur
Vice President, Heavy Oil

Chad L. Kalmakoff
Vice President, Finance

Scott Lovett
Vice President, Corporate Development

AUDITORS

KPMG LLP

RESERVES ENGINEERS

McDaniel & Associates Consultants

TRANSFER AGENT

Odyssey Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Symbol: BTE