2020

Q2 Report

BAYTEX

TSX BTE | NYSE BTE

BAYTEX ANNOUNCES SECOND QUARTER 2020 FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA (July 29, 2020) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three and six months ended June 30, 2020 (all amounts are in Canadian dollars unless otherwise noted).

"During the second quarter we took decisive steps to adjust our business model in the face of extremely volatile crude oil markets. We are now starting to benefit from the actions we have taken as we generated positive free cash flow during the quarter and maintained approximately $300 million of financial liquidity. We restarted approximately 80% of the previously announced shut-in volumes, which we expect will positively impact our adjusted funds flow for the remainder of the year," commented Ed LaFehr, President and Chief Executive Officer.

Q2 2020 Highlights

- Generated production of 72,508 boe/d (81% oil and NGL), consistent with our previously announced guidance range for the second quarter of 72,000 to 73,000 boe/d.
- Delivered adjusted funds flow of $18 million ($0.03 per basic share).
- Realized an operating netback (inclusive of realized financial derivatives gain) of $8.02/boe.
- Reduced net debt by $57 million as the Canadian dollar strengthened relative to the U.S. dollar and we generated positive free cash flow of $6 million.
- Maintained undrawn credit capacity of $363 million and liquidity, net of working capital, of approximately $300 million.
- Achieved a 15% reduction in our GHG emissions intensity in 2019 and remain committed to our 30% target by the end of 2021.

2020 Outlook

We continue to forecast annual capital spending of $260 to $290 million, an approximate 50% reduction from our original plan of $500 to $575 million. With this revised capital program, we suspended drilling operations in Canada and moderated the pace of activity in the Eagle Ford.

We previously announced voluntary production shut-ins of approximately 25,000 boe/d. These volumes remained off-line for April and May. As operating netbacks improved in June, we initiated plans to bring approximately 80% of these volumes back on-line. At current commodity prices, the resumption of production from these previously shut-in barrels is expected to have a positive impact on our adjusted funds flow and improve our financial liquidity. For the second half of 2020, we currently project about 5,000 boe/d of heavy oil production to remain shut-in.

On June 25, we revised our production guidance range for 2020 to 78,000 to 82,000 boe/d, from 70,000 to 74,000 boe/d previously, taking into account the production brought back on-line. Should operating netbacks change, we have the ability to shut-in additional volumes or restart wells in short order.

We remain intensely focused on driving further efficiencies to capture or sustain cost reductions identified during this downturn, while protecting the health and safety of our personnel.

	Three Months Ended			Six Months Ended	
	June 30, 2020	March 31, 2020	June 30, 2019	**June 30, 2020**	June 30, 2019
FINANCIAL					
(thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 152,689**	$ 336,614	$ 482,000	**$ 489,303**	$ 935,424
Adjusted funds flow (1)	**17,887**	132,935	236,130	**150,822**	456,900
Per share - basic	**0.03**	0.24	0.42	**0.27**	0.82
Per share - diluted	**0.03**	0.24	0.42	**0.27**	0.82
Net income (loss)	**(138,463)**	(2,498,217)	78,826	**(2,636,680)**	90,162
Per share - basic	**(0.25)**	(4.46)	0.14	**(4.71)**	0.16
Per share - diluted	**(0.25)**	(4.46)	0.14	**(4.71)**	0.16
Capital Expenditures					
Exploration and development expenditures (1)	**$ 9,852**	$ 176,777	$ 106,246	**$ 186,629**	$ 260,089
Acquisitions, net of divestitures	**(11)**	(40)	1,647	**(51)**	1,647
Total oil and natural gas capital expenditures	**$ 9,841**	$ 176,737	$ 107,893	**$ 186,578**	$ 261,736
Net Debt					
Bank loan (2)	**$ 704,135**	$ 678,740	$ 414,691	**$ 704,135**	$ 414,691
Long-term notes (2)	**1,225,395**	1,270,800	1,543,645	**1,225,395**	1,543,645
Long-term debt	**1,929,530**	1,949,540	1,958,336	**1,929,530**	1,958,336
Working capital deficiency	**65,423**	102,077	70,350	**65,423**	70,350
Net debt (1)	**$ 1,994,953**	$ 2,051,617	$ 2,028,686	**$ 1,994,953**	$ 2,028,686
Shares Outstanding - basic (thousands)					
Weighted average	**560,512**	559,804	556,599	**560,158**	556,022
End of period	**560,545**	560,483	556,798	**560,545**	556,798
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 27.85**	$ 46.17	$ 59.81	**$ 37.01**	$ 57.36
MEH oil (US$/bbl)	**26.40**	49.54	66.37	**37.97**	63.42
MEH oil differential to WTI (US$/bbl)	**(1.45)**	3.37	6.56	**0.96**	6.06
Edmonton par ($/bbl)	**29.85**	51.43	73.84	**40.64**	70.19
Edmonton par differential to WTI (US$/bbl)	**(6.31)**	(7.92)	(4.61)	**(7.24)**	(4.72)
WCS heavy oil ($/bbl)	**22.70**	34.48	65.73	**28.68**	61.17
WCS differential to WTI (US$/bbl)	**(11.47)**	(20.53)	(10.68)	**(16.00)**	(11.48)
Natural gas					
NYMEX (US$/mmbtu)	**$ 1.72**	$ 1.95	$ 2.64	**$ 1.83**	$ 2.89
AECO ($/mcf)	**1.91**	2.14	1.17	**2.03**	1.56
CAD/USD average exchange rate	**1.3860**	1.3445	1.3376	**1.3653**	1.3334

	Three Months Ended			Six Months Ended	
	June 30, 2020	March 31, 2020	June 30, 2019	**June 30, 2020**	June 30, 2019
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**38,951**	45,717	42,585	**42,333**	43,809
Heavy oil (bbl/d)	**11,832**	28,854	27,320	**20,343**	27,107
NGL (bbl/d)	**7,634**	7,822	10,986	**7,728**	11,356
Total liquids (bbl/d)	**58,417**	82,393	80,891	**70,404**	82,272
Natural gas (mcf/d)	**84,546**	96,356	105,065	**90,451**	104,874
Oil equivalent (boe/d @ 6:1) (3)	**72,508**	98,452	98,402	**85,479**	99,751
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (4)	**$ 147,229**	$ 315,257	$ 461,110	**$ 462,486**	$ 897,746
Royalties	**(29,156)**	(56,720)	(86,617)	**(85,876)**	(167,942)
Operating expense	**(73,680)**	(104,470)	(100,474)	**(178,150)**	(200,766)
Transportation expense	**(5,031)**	(10,342)	(11,869)	**(15,373)**	(25,199)
Operating netback (1)	**$ 39,362**	**$ 143,725**	**$ 262,150**	**$ 183,087**	**$ 503,839**
General and administrative	**(7,438)**	(9,775)	(11,506)	**(17,213)**	(25,642)
Cash financing and interest	**(27,387)**	(28,535)	(28,092)	**(55,922)**	(56,276)
Realized financial derivatives gain	**13,624**	26,850	12,993	**40,474**	31,807
Other (5)	**(274)**	670	585	**396**	3,172
Adjusted funds flow (1)	**$ 17,887**	**$ 132,935**	**$ 236,130**	**$ 150,822**	**$ 456,900**
Netback (per boe)					
Total sales, net of blending and other expense (4)	**$ 22.31**	$ 35.19	$ 51.49	**$ 29.73**	$ 49.72
Royalties	**(4.42)**	(6.33)	(9.67)	**(5.52)**	(9.30)
Operating expense	**(11.17)**	(11.66)	(11.22)	**(11.45)**	(11.12)
Transportation expense	**(0.76)**	(1.15)	(1.33)	**(0.99)**	(1.40)
Operating netback (1)	**$ 5.96**	**$ 16.05**	**$ 29.27**	**$ 11.77**	**$ 27.90**
General and administrative	**(1.13)**	(1.09)	(1.28)	**(1.11)**	(1.42)
Cash financing and interest	**(4.15)**	(3.19)	(3.14)	**(3.59)**	(3.12)
Realized financial derivatives gain	**2.06**	3.00	1.45	**2.60**	1.76
Other (5)	**(0.03)**	0.07	0.07	**0.02**	0.19
Adjusted funds flow (1)	**$ 2.71**	**$ 14.84**	**$ 26.37**	**$ 9.69**	**$ 25.31**

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 bank loan 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, and current income tax expense or recovery. Refer to the Q2/2020 MD&A for further information on these amounts.

Q2/2020 Results

During the second quarter we took decisive steps to adjust our business plan in the face of extremely volatile crude oil markets. In addition to voluntarily shutting-in production, we suspended drilling operations in Canada and moderated our pace of activity in the Eagle Ford. As a result, exploration and development spending totaled a modest $10 million during the second quarter.

Production during the second quarter averaged 72,508 boe/d (81% oil and NGL), as compared to 98,452 boe/d (83% oil and NGL) in Q1/2020. Production in Canada averaged 37,691 boe/d (83% oil and NGL), as compared to 62,262 boe/d in Q1/2020, while production in the Eagle Ford averaged 34,817 boe/d (77% oil and NGL), as compared to 36,190 boe/d in Q1/2020. Our second quarter production was reduced by approximately 20,000 boe/d due to the voluntary shut-ins.

We delivered adjusted funds flow of $18 million ($0.03 per basic share) in Q2/2020 and generated an operating netback of $5.96/boe ($8.02/boe inclusive of realized financial derivatives gain). The Eagle Ford generated an operating netback of $10.05/boe and our Canadian operations generated an operating netback of $2.19/boe.

We continue to emphasize cost reductions across all facets of our organization. We have identified approximately $98 million of cost reductions for 2020 (operating, transportation and general & administrative expenses). During the second quarter, our operating expense of $11.17/boe compared favorably to $11.66/boe in Q1/2020 as we strive to mitigate the costs associated with our field operations. In addition, we realized an approximate 35% reduction in our per boe transportation expense due to reduced volumes. General and administrative expense totaled $7.4 million ($1.13/boe) in Q2/2020, down from $9.8 million ($1.09/boe) in Q1/2020 as we implemented reductions to salaries and annual retainers and benefited from the Canadian Emergency Wage Subsidy.

Eagle Ford and Viking Light Oil

In the Eagle Ford, strong well performance continued across our acreage position. In Q2/2020, we commenced production from 17 (4.6 net) wells. These wells were brought on-stream in April and generated an average 30-day initial production rate of approximately 1,550 boe/d per well. We expect to bring approximately 16 to 18 net wells on production in the Eagle Ford in 2020, down from our original guidance of 22 net wells.

Production in the Viking averaged 19,717 boe/d (90% oil and NGL) during Q2/2020, as compared to 24,696 boe/d in Q1/2020. The quarterly impact of voluntary shut-ins in the Viking was approximately 2,000 boe/d. As operating netbacks improved in June, these volumes were brought back on-line. We suspended all drilling in the Viking, and as such, there was limited activity during the second quarter. In the first half of 2020, we invested $79 million on exploration and development in the Viking and commenced production from 83 (78.5 net) wells.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 13,082 boe/d (91% oil and NGL) during the second quarter, as compared to 31,211 boe/d in Q1/2020. The quarterly impact of voluntary shut-ins for heavy oil was approximately 17,000 boe/d. We suspended all heavy oil drilling, and as such, there was limited activity during the second quarter. In the first half of 2020, we invested $40 million on exploration and development and drilled 33 (33.0 net) wells. For the second half of 2020, we currently project about 5,000 boe/d of heavy oil production to remain shut-in.

Pembina Area Duvernay Light Oil

Production in the Pembina Duvernay averaged 717 boe/d (85% oil and NGL) during Q2/2020, as compared to 1,717 boe/d in Q1/2020. The quarterly impact of voluntary shut-ins for the Pembina Duvernay was approximately 1,000 boe/d. As operating netbacks improved in June, these volumes were brought back on-line.

In Q1/2020, we drilled two wells in the core of our Pembina acreage, bringing total wells drilled to nine in this area. Completion activities, originally scheduled for Q2/2020 have been deferred.

Financial Liquidity

Our credit facilities total approximately $1.1 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, 2020, we had $363 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of approximately $300 million. In addition, our first long-term note maturity of US$400 million is not until June 2024.

Our net debt, which includes our bank loan, long-term notes and working capital, totaled $2.0 billion at June 30, 2020. Based on the forward strip(1), we expect to maintain our financial liquidity and remain onside with our financial covenants through 2021.

Note:

(1) 2020 full year pricing assumptions: WTI - US$39/bbl; WCS differential - US$14/bbl; MSW differential – US$6/bbl, NYMEX Gas - US$1.90/mcf; AECO Gas - $2.05/mcf and Exchange Rate (CAD/USD) - 1.36. 2021 full year pricing assumptions: WTI - US$41/bbl; WCS differential - US$15/bbl; MSW differential – US$7/bbl, NYMEX Gas - US$2.60/mcf; AECO Gas - $2.35/mcf and Exchange Rate (CAD/USD) - 1.36.

Financial Covenants

The following table summarizes the financial covenants applicable to the credit facilities and Baytex's compliance therewith as at June 30, 2020.

Covenant Description	Position as at June 30, 2020	Covenant
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	1.0:1.0	3.5:1.0
Interest Coverage(3) (Minimum Ratio)	6.6:1.0	2.0:1.0

Notes:

(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, 2020, the Company's Senior Secured Debt totaled $719.9 million which includes $704.1 million of principal amounts outstanding and $15.8 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, 2020 was $704.4 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, 2020 was $106.5 million.

Risk Management

To manage commodity price movements, we utilize various financial derivative contracts and crude-by-rail to reduce the volatility of our adjusted funds flow. The following table summarizes our crude oil hedges in place.

	Q3/2020	Q4/2020	2021
WTI Fixed Hedges			
Volumes (bbl/d)	23,732	8,000	---
Fixed Price (US$/bbl)	$36.41	$42.78	---
WTI 3-Way Option (1)			
Volumes (bbl/d)	24,500	24,500	5,000
Baytex Receives (2) (3) (4)	WTI plus US$7.60	WTI plus US$7.60	US$45/bbl
Total Volumes (bbl/d)	48,232	32,500	5,000

Notes:

(1) WTI 3-way options consist of a sold put, a bought put and a sold call. Baytex's average sold put, bought put and sold call for Q3/2020 and Q4/2020 are US$50.44/bbl, US$58.04/bbl and US$63.06/bbl, respectively. Baytex's average sold put, bought put and sold call for 2021 are US$35/bbl, US$45/bbl and US$55/bbl, respectively.
(2) For Q3/2020 and Q4/2020, Baytex receives WTI plus US$7.60/bbl when WTI is at or below US$50.44/bbl; Baytex receives US$58.04/bbl when WTI is between US$50.44/bbl and US$58.04/bbl; Baytex receives WTI when WTI is between US$58.04/bbl and US$63.06/bbl; and Baytex receives US$63.06/bbl when WTI is above US$63.06/bbl.

(3) For 2021, Baytex receives WTI plus US$10/bbl when WTI is at or below US$35/bbl; Baytex receives US$45/bbl when WTI is between US$35/bbl and US$45/bbl; Baytex receives WTI when WTI is between US$45/bbl and US$55/bbl; and Baytex receives US$55/bbl when WTI is above US$55/bbl.
(4) Based on the forward strip for the balance of 2020, Baytex will receive WTI plus US$7.60/bbl. Based on the forward strip for 2021, Baytex will receive US$45/bbl.

For the remainder of 2020, we also have WTI-MSW basis differential swaps for 7,783 bbl/d of our light oil production in Canada at US$5.80/bbl and WCS differential hedges on 8,667 bbl/d at a WTI-WCS differential of US$14.57/bbl.

Crude-by-rail is an integral part of our egress and marketing strategy for our heavy oil production. For Q2/2020, we delivered approximately 5,250 bbl/d of our heavy oil volumes to market by rail.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q2/2020 financial statements.

Sustainability

We are committed to managing the environmental and social impacts of our business and continual improvement is an important element of this commitment. In 2019, Baytex established for the first time a GHG emissions reduction target. Our objective is to reduce our corporate GHG emission intensity (tonnes of CO2 per boe) by 30% by 2021, relative to our 2018 baseline.

In 2019, we made significant improvements in our emissions profile, achieving a 15% reduction in our GHG emissions intensity as we commissioned our Peace River gas plant in mid-2018 and progressed our Viking gas conservation project. We remain committed to achieving our 30% target by the end of 2021.

2020 Guidance

There is no change to our guidance announced June 25, 2020.

	2020 Guidance
Exploration and development expenditures	$260 - $290 million
Production (boe/d)	78,000 - 82,000
Expenses:	
Royalty rate	~ 18.5%
Operating	$11.75 - $12.50/boe
Transportation	$0.95 - $1.05/boe
General and administrative	$38 million ($1.30/boe)
Interest	$112 million ($3.84/boe)
Leasing expenditures	$7 million
Asset retirement obligations	$10 million

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 30, 2020 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 30, 2020, 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/baytexq220200730.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; restarted shut-in volumes will have a positive impact on our adjusted funds flow; that the resumption of production from shut-in barrels is expected to positively impact adjusted funds flow and improve financial liquidity; our ability to re-start shut in wells or shut-in additional volumes; we expect 5,000 boe/d of heavy oil to remain shut-in for H2/2020; we are focused on further efficiencies to capture or sustain cost reduction while protecting the health and safety of our personnel; that we have identified $98 million of cost reductions for 2020 and continue to emphasize cost reductions; the number of Eagle Ford wells we expect to bring online in 2020; that we expect to maintain our financial liquidity and remain onside our financial covenants through 2021; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility; that we are committed to managing the environmental and social impacts of our business; that we are committed to achieving our 30% emissions intensity target; and our guidance for 2020 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations.

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, 2019, 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, 2020.

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 bank loan. 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 bank loan 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 bank loan 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, 2020. 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, 2020					**Six Months Ended June 30, 2020**				
	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	4,735	6	15	6,278	5,802	9,377	7	14	9,450	10,973
Lloydminster	7,098	10	—	1,039	7,281	10,966	14	—	1,160	11,174
Canada - Light										
Viking	—	17,735	105	11,267	19,717	—	20,110	109	11,925	22,206
Duvernay	—	430	176	670	717	—	680	348	1,381	1,258
Remaining Properties	—	581	638	17,728	4,174	—	690	654	18,124	4,365
United States										
Eagle Ford	—	20,189	6,701	47,564	34,817	—	20,832	6,603	48,410	35,503
Total	11,832	38,951	7,634	84,546	72,508	20,343	42,333	7,728	90,451	85,479

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 83% of Baytex's production is weighted toward crude oil and natural gas liquids. Baytex's common shares trade on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE.

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

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BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three and six months ended June 30, 2020 and 2019
Dated July 29, 2020

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, 2020. This information is provided as of July 29, 2020. 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, 2020 ("Q2/2020" and "YTD 2020") have been compared with the results for the three and six months ended June 30, 2019 ("Q2/2019" and "YTD 2019"). 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, 2020, its audited comparative consolidated financial statements for the years ended December 31, 2019 and 2018, together with the accompanying notes, and its Annual Information Form for the year ended December 31, 2019. 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.

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 oil and gas company based in Calgary, Alberta. The company operates in Canada and the United States. 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.

CURRENT ENVIRONMENT

In March 2020, the World Health Organization declared a global pandemic related to the novel coronavirus ("COVID-19"). The emergence of COVID-19 and the steps taken by governments to control the spread of the virus has resulted in significant instability in the global economy. The oil and gas industry has been severely impacted as actions taken to limit the spread of COVID-19 have resulted in a sharp decline in demand for crude oil. This combined with the increased supply of crude oil due to the Russia and Saudi Arabia price war resulted in an unprecedented collapse in global crude oil prices and significant volatility leading into Q2/2020. Global crude oil prices began to recover in Q2/2020 as members of OPEC+ agreed to historic production curtailments and governments began to ease restrictions that allowed economies to begin reopening. While these factors have resulted in recent improvements in crude oil prices the outlook for our industry remains uncertain due to the ongoing spread of COVID-19.

We have taken significant action in response to the uncertain outlook for our industry. With the health and safety of our personnel at the forefront, we have transitioned to a work-from-home program, where possible, that ensures the continuity of business as the COVID-19 pandemic continues. In March, we established a COVID-19 response team to coordinate, establish and implement our response measures. We have restricted travel, adjusted work schedules and continue to adhere to recommendations from applicable government and public health agencies.

We have also taken steps to preserve our financial liquidity. Exploration and development expenditures have been reduced with a moderated pace of development in the U.S. and a suspension of development operations in Canada. We also shut-in approximately 25,000 boe/d of production during April and May as operating netbacks were challenged by the sharp decline in crude oil prices. Approximately 80% of these volumes were brought back online in June after OPEC+ production cuts resulted in improved realized prices and operating netbacks. We currently have approximately 5,000 boe/d of heavy oil production shut-in which will be brought back online when pricing is supportive. As a result of these actions we have maintained $363.0 million of availability on our credit facilities at June 30, 2020 and we are forecasting compliance with the financial covenants in our credit facilities through at least December 31, 2021 at current forward prices.

The global health crisis surrounding COVID-19 has impacted our results for YTD 2020 and has resulted in heightened uncertainty regarding the outlook and future performance of our business. We do not know the extent and duration to which COVID-19 will impact the demand and price for oil. The overall effect on our business will depend on how quickly the world economy resumes activity which is highly dependent on the progression of the pandemic and the success of measures taken to prevent its spread.

SECOND QUARTER HIGHLIGHTS

Our financial and operating results for Q2/2020 reflect our actions to mitigate the impact of COVID-19 on our business. Production averaged 72,508 boe/d as we proactively shut-in production in April and May when prices were uneconomic and we suspended our Canadian capital program. With reduced development spending in the U.S., the suspension of our Canadian capital program and proactively shutting-in production, we were able to generate free cash flow of $5.9 million in Q2/2020 preserving our liquidity during this period of uncertainty. We had $363.0 million available on our credit facilities at June 30, 2020 and our first debt maturity is not until 2024.

In Canada, production was 37,691 boe/d for Q2/2020 which is 36% lower than 58,580 boe/d in Q2/2019 and is the result of shutting-in approximately 25,000 boe/d of production for April and May and suspending development activity during this period of volatile commodity prices. Approximately 80% of the shut-in volumes were restored by the end of Q2/2020. We did not drill any wells in our Canadian operations during Q2/2020 but had exploration and development expenditures of $2.9 million associated with completing primary development on a polymer flood project at Lloydminster that was initiated in Q1/2020.

In the U.S., we invested $6.9 million on exploration and development activity during Q2/2020 and commenced production from 17 (4.6 net) wells. These wells were brought on production in April and the majority of the costs were incurred in Q1/2020. Completion operations were suspended for the remainder of Q2/2020 which resulted in production declining to 34,817 boe/d compared to 39,822 boe/d for Q2/2019 when we commenced production from 29 (5.0 net) wells.

Global benchmark prices for crude oil were relatively strong leading into 2020 but declined rapidly in March 2020 as Saudi Arabia and Russia increased production of crude oil as demand was falling due to the spread of COVID-19. The unprecedented volatility in global benchmark prices continued throughout Q2/2020 despite a historic production curtailment agreement between members of the OPEC+ group to limit supply. Concerns about a lack of crude oil storage capacity along with decreased demand for crude oil as a result of the COVID-19 health crisis continue to weigh on crude oil prices. The WTI benchmark price averaged US$27.85/bbl for Q2/2020 compared to US$59.81/bbl during Q2/2019.

Adjusted funds flow was $17.9 million in Q2/2020 compared to $236.1 million for Q2/2019. Our financial and operating results for Q2/2020 were overshadowed by an unprecedented decline in crude oil prices combined with shut-in production which caused a $222.8 million decrease in operating netback relative to Q2/2019. The $256.4 million decrease in revenue, net of royalties and blending and other expense, was mitigated by our cost savings initiatives which resulted in a $37.7 million decrease in operating, transportation, and general and administrative expenses for Q2/2020 compared to Q2/2019. The decrease in adjusted funds flow for Q2/2020 was the primary factor resulting in a net loss of $138.5 million for Q2/2020 compared to net income of $78.8 million in Q2/2019.

Net debt was $2.0 billion at June 30, 2020 compared to $1.9 billion at December 31, 2019. The increase in net debt is primarily the result of a $60.1 million increase in the reported amount of our U.S. dollar denominated net debt, due to a weaker Canadian dollar at June 30, 2020, along with exploration and development expenditures that exceeded adjusted funds flow by $35.8 million.

2020 GUIDANCE

We previously announced that we had voluntarily shut-in approximately 25,000 boe/d of production. These volumes remained off-line for April and May. As operating netbacks improved in June, we brought approximately 80% of these volumes back on-line. At current commodity prices, we expect that the resumption of production from these previously shut-in barrels will have a positive impact on our adjusted funds flow and improve our financial liquidity. We currently have approximately 5,000 boe/d of heavy oil production shut-in.

We continue to emphasize cost reductions across all facets of our organization. On a per unit basis, our operating expense guidance is unchanged as we drive further efficiencies in our business to mitigate the fixed costs associated with our field operations. Transportation costs associated with the production brought back on-line has modestly increased our annual guidance for transportation expenses. We have also reduced our general and administrative expense guidance to $38 million ($1.30/boe). All full-time employee salaries and all annual retainers paid to our directors were reduced by 10% effective April 1, 2020 and we continue to benefit from extensions to the Canadian Emergency Wage Subsidy.

The following table compares our updated 2020 guidance to our previously announced guidance and our YTD 2020 results.

	Previous Annual Guidance [1]	Revised Annual Guidance [2]	YTD 2020 Results
Exploration and development expenditures ($ millions)	$260 - $290	no change	$186.6
Production (boe/d)	70,000 - 74,000	78,000 - 82,000	85,479
Expenses:			
Royalty rate (%)	~20.0	~18.5	18.6
Operating ($/boe)	$11.75 - $12.50	no change	$11.45
Transportation ($/boe)	$0.80 - $0.90	$0.95 - $1.05/boe	$0.99
General and administrative ($ millions)	$40 ($1.52/boe)	$38 ($1.30/boe)	$17.2 ($1.11/boe)
Cash interest ($ millions)	$120 ($4.57/boe)	$112 ($3.84/boe)	$55.9 ($3.59/boe)
Leasing expenditures ($ millions)	$7	no change	$3.0
Asset retirement obligations ($ millions)	$10	no change	$4.9

(1) As announced on May 7, 2020.
(2) As announced on June 25, 2020.

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					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**18,762**	**20,189**	**38,951**	22,130	20,455	42,585
Heavy oil	**11,832**	**—**	**11,832**	27,320	—	27,320
Natural Gas Liquids (NGL)	**933**	**6,701**	**7,634**	1,106	9,880	10,986
Total liquids (bbl/d)	**31,527**	**26,890**	**58,417**	50,556	30,335	80,891
Natural gas (mcf/d)	**36,982**	**47,564**	**84,546**	48,145	56,920	105,065
Total production (boe/d)	**37,691**	**34,817**	**72,508**	58,580	39,822	98,402
Production Mix						
Segment as a percent of total	**52 %**	**48 %**	**100 %**	60 %	40 %	100 %
Light oil and condensate	**50 %**	**58 %**	**54 %**	38 %	51 %	43 %
Heavy oil	**31 %**	**— %**	**16 %**	47 %	— %	28 %
NGL	**2 %**	**19 %**	**11 %**	2 %	25 %	11 %
Natural gas	**17 %**	**23 %**	**19 %**	13 %	24 %	18 %

	Six Months Ended June 30					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**21,501**	**20,832**	**42,333**	22,709	21,100	43,809
Heavy oil	**20,343**	**—**	**20,343**	27,107	—	27,107
Natural Gas Liquids (NGL)	**1,125**	**6,603**	**7,728**	1,356	10,000	11,356
Total liquids (bbl/d)	**42,969**	**27,435**	**70,404**	51,172	31,100	82,272
Natural gas (mcf/d)	**42,041**	**48,410**	**90,451**	48,742	56,132	104,874
Total production (boe/d)	**49,976**	**35,503**	**85,479**	59,296	40,455	99,751
Production Mix						
Segment as a percent of total	**58 %**	**42 %**	**100 %**	59 %	41 %	100 %
Light oil and condensate	**43 %**	**59 %**	**50 %**	38 %	52 %	44 %
Heavy oil	**41 %**	**— %**	**24 %**	46 %	— %	27 %
NGL	**2 %**	**19 %**	**9 %**	2 %	25 %	11 %
Natural gas	**14 %**	**22 %**	**17 %**	14 %	23 %	18 %

Production was 72,508 boe/d for Q2/2020 and 85,479 boe/d for YTD 2020 compared to 98,402 boe/d for Q2/2019 and 99,751 boe/d for YTD 2019. Our production results for Q2/2020 and YTD 2020 were in line with our expectations and reflect the production we shut-in in Canada and the moderated pace of activity in the U.S. following the sharp decline in crude oil prices in March 2020. With our development program limited to our U.S. operations and the majority of our shut-in production being heavy oil, our light oil and condensate production increased to 54% of our total production compared to 43% and our U.S. production increased to 48% of total production in Q2/2020 from 40% in Q2/2019.

In Canada, production was 37,691 boe/d for Q2/2020 and 49,976 boe/d for YTD 2020 compared to 58,580 boe/d for Q2/2019 and 59,296 boe/d for YTD 2019. Lower production in both periods of 2020 is a result of lower development activity relative to the comparative periods of 2019 along with shutting in approximately 25,000 boe/d of low and negative margin production for April and May with approximately 80% of these volumes back online in June.

Production in the U.S. was 34,817 boe/d for Q2/2020 and 35,503 boe/d for YTD 2020 compared to 39,822 boe/d for Q2/2019 and 40,455 boe/d for YTD 2019. U.S. production was lower for both periods of 2020 which reflects the timing of completion activity during Q2/2020 and fewer wells brought on production in YTD 2020 relative to YTD 2019. We initiated production from 17 (4.6 net) wells during Q2/2020 and 48 (11.0 net) wells during YTD 2020 compared to 29 (5.0 net) in Q2/2019 and 65 (14.0 net) wells in YTD 2019.

Our annual guidance range of 78,000 to 82,000 boe/d reflects suspended development activity in Canada for the remainder of 2020 along with a moderated pace of activity in the U.S. We currently project approximately 5,000 boe/d of heavy oil production to remain shut-in. We have the ability to shut-in additional volumes or restart production should our operating netbacks change.

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 were relatively strong leading into 2020 as stable demand and production outlooks continued from Q4/2019. Benchmark prices declined rapidly in March and April 2020 after members of the OPEC+ group began to increase the supply of crude oil to the global market and measures to limit the spread of COVID-19 resulted in a significant decrease in the demand for crude oil. The unprecedented volatility in global benchmark prices continued throughout Q2/2020 following a historic production curtailment agreement between members of the OPEC+ group to limit supply. Concerns about a lack of crude oil storage capacity along with decreased demand for crude oil as a result of the COVID-19 health crisis continue to weigh on crude oil prices.

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$26.40/bbl during Q2/2020 and US$37.97/bbl during YTD 2020 compared to US$66.37/bbl during Q2/2019 and US$63.42/bbl during YTD 2019. The MEH benchmark was at a US$1.45/bbl discount to WTI in Q2/2020 and a US$0.96/bbl premium to WTI in YTD 2020 compared to a US$6.56/bbl and US$6.06/bbl premium to WTI during Q2/2019 and YTD 2019. The decrease in the MEH benchmark premium to WTI was a result of an increase in supply at the Magellan East terminal due to higher oil production in Texas relative to both periods in 2019.

Prices for Canadian oil trade at a discount due to a lack of egress to diversified markets from Western Canada. Canadian oil differentials were wider in YTD 2020 compared to YTD 2019. Production curtailments mandated by the Government of Alberta came into effect in January 2019 and resulted in a significant narrowing of differentials for light and heavy grades of Canadian oil. Reductions in curtailment volumes combined with additional production in Western Canada caused these differentials to widen in early 2020. The WCS differential narrowed to US$4.34/bbl in June 2020 after heavy oil production in Western Canada was shut-in due to the decline in North American crude oil prices during Q2/2020.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price which is the representative benchmark for light grades of crude oil in Western Canada. The Edmonton par price averaged $29.85/bbl during Q2/2020 and $40.64/bbl during YTD 2020 compared to $73.84/bbl during Q2/2019 and $70.19/bbl during YTD 2019. Edmonton par traded at a discount to WTI of US$6.31/bbl for Q2/2020 and US$7.24/bbl for YTD 2020 compared to a discount of US$4.61/bbl for Q2/2019 and US$4.72/bbl for YTD 2019. The Edmonton par differential to WTI was narrower in Q2/2020 relative to Q2/2019 other than the month of May when the differential widened to US$14.47/bbl due to a lack of demand. This widening skewed the average differential resulting in a wider differential in Q2/2020.

The price received for our heavy oil production in Canada is based on the WCS benchmark price which is the representative benchmark for heavy grades of crude oil in Western Canada. The WCS heavy oil price averaged $22.70/bbl for Q2/2020 and $28.68/bbl for YTD 2020 as compared to $65.73/bbl for Q2/2019 and $61.17/bbl for YTD 2019. The WCS heavy oil differential was US$11.47/bbl in Q2/2020 and US$16.00/bbl in YTD 2020 compared to US$10.68/bbl for Q2/2019 and US$11.48/bbl for YTD 2019.

Natural Gas

U.S. natural gas prices for Q2/2020 and YTD 2020 were lower than Q2/2019 and YTD 2019 as higher U.S. natural gas production outpaced growth in natural gas demand. Canadian natural gas prices remained challenged during Q2/2020 and YTD 2020 as a lack of egress from Western Canada continues to impact natural gas prices in the region.

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$1.72/mmbtu in Q2/2020 and US$1.83/mmbtu in YTD 2020 which is lower compared to US$2.64/mmbtu in Q2/2019 and US$2.89/mmbtu in YTD 2019. Increasing natural gas production levels in the U.S. resulted in an oversupplied North American market and lower natural gas prices in YTD 2020 relative to YTD 2019.

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 $1.91/mcf during Q2/2020 and $2.03/mcf during YTD 2020 which is higher than $1.17/mcf for Q2/2019 and $1.56/mcf for YTD 2019. The AECO gas benchmark was higher in both periods of 2020 relative to 2019 due to lower associated gas production following the shut-in of oil production in Western Canada during both periods of 2020.

The following tables compare select benchmark prices and our average realized selling prices for the three and six months ended June 30, 2020 and 2019.

	Three Months Ended June 30			Six Months Ended June 30		
	2020	2019	Change	**2020**	2019	Change
Benchmark Averages						
WTI oil (US$/bbl)(1)	**27.85**	59.81	(31.96)	**37.01**	57.36	(20.35)
MEH oil (US$/bbl)(2)	**26.40**	66.37	(39.97)	**37.97**	63.42	(25.45)
MEH oil differential to WTI (US$/bbl)	**(1.45)**	6.56	(8.01)	**0.96**	6.06	(5.10)
Edmonton par oil ($/bbl)	**29.85**	73.84	(43.99)	**40.64**	70.19	(29.55)
Edmonton par oil differential to WTI (US$/bbl)	**(6.31)**	(4.61)	(1.70)	**(7.24)**	(4.72)	(2.52)
WCS heavy oil ($/bbl)(3)	**22.70**	65.73	(43.03)	**28.68**	61.17	(32.49)
WCS heavy oil differential to WTI (US$/bbl)	**(11.47)**	(10.68)	(0.79)	**(16.00)**	(11.48)	(4.52)
AECO natural gas price ($/mcf)(4)	**1.91**	1.17	0.74	**2.03**	1.56	0.47
NYMEX natural gas price (US$/mmbtu)(5)	**1.72**	2.64	(0.92)	**1.83**	2.89	(1.06)
CAD/USD average exchange rate	**1.3860**	1.3376	0.0484	**1.3653**	1.3334	0.0318

(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) WCS refers to the average posting price for the benchmark WCS heavy oil.
(4) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(5) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Three Months Ended June 30					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)	**$ 24.73**	**$ 33.23**	**$ 29.14**	$ 70.43	$ 82.47	$ 76.21
Heavy oil ($/bbl)(1)	**17.22**	**—**	**17.22**	50.34	—	50.34
NGL ($/bbl)	**9.98**	**13.18**	**12.79**	17.46	17.58	17.57
Natural gas ($/mcf)	**1.86**	**2.38**	**2.15**	1.16	3.47	2.41
Weighted average ($/boe)(1)	**$ 19.79**	**$ 25.05**	**$ 22.31**	$ 51.36	$ 51.69	$ 51.49

	Six Months Ended June 30					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)	**$ 38.67**	**$ 48.05**	**$ 43.29**	$ 66.71	$ 79.19	$ 72.72
Heavy oil ($/bbl)(1)	**19.72**	**—**	**19.72**	46.07	—	46.07
NGL ($/bbl)	**10.72**	**14.04**	**13.56**	21.18	20.23	20.34
Natural gas ($/mcf)	**1.94**	**2.50**	**2.24**	1.77	3.71	2.81
Weighted average ($/boe)(1)	**$ 26.53**	**$ 34.22**	**$ 29.73**	$ 48.55	$ 51.44	$ 49.72

(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 $22.31/boe for Q2/2020 and $29.73/boe for YTD 2020 compared to $51.49/boe for Q2/2019 and $49.72/boe for YTD 2019. Our realized price in the U.S. was $25.05/boe in Q2/2020 which is $26.64/boe lower than $51.69/boe in Q2/2019 due to the decrease in U.S. commodity benchmark prices. In Canada, our realized price of $19.79/boe for Q2/2020 was $31.57/boe lower than $51.36/boe for Q2/2019 due to the decrease in Canadian commodity benchmark prices.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price was $24.73/bbl in Q2/2020 and $38.67/bbl in YTD 2020 compared to $70.43/bbl in Q2/2019 and $66.71/bbl in YTD 2019. Our realized light oil and condensate price for Q2/2020 and YTD 2020 represents a discount of $5.12/bbl and $1.97/bbl to the Edmonton par price compared to discounts of $3.41/bbl in Q2/2019 and $3.48/bbl in YTD 2019. The discount of $5.12/bbl for Q2/2020 was impacted by certain fixed price physical delivery contracts which were entered prior to the month of delivery to secure pricing and support production. Our YTD 2020 discount of $1.97/bbl reflects improved price realizations on our light oil production relative to YTD 2019 when our discount to the Edmonton par price was $3.48/bbl. Without the impact of physical delivery contracts, we expect to receive a $2.50/bbl to $3.50/bbl discount to the Edmonton par price for the balance of 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 $33.23/bbl for Q2/2020 and $48.05/bbl for YTD 2020 compared to $82.47/bbl for Q2/2019 and $79.19/bbl for YTD 2019. Expressed in U.S. dollars, our realized light oil and condensate price of US$23.98/bbl for Q2/2020 and US $35.19/bbl for YTD 2020 represents a US$2.43/bbl discount to MEH for Q2/2020 and a discount of US$2.77/bbl for YTD 2020. A change in marketing contracts during Q3/2019 resulted in improved price realizations for both periods of 2020 relative to Q2/2019 and YTD 2019 when our discount to MEH was US$4.71/bbl and US$4.03/bbl, respectively.

Our realized heavy oil price, net of blending and other expense averaged $17.22/bbl in Q2/2020 and $19.72/bbl in YTD 2020 compared to $50.34/bbl in Q2/2019 and $46.07/bbl in YTD 2019. Our realized heavy oil price for Q2/2020 and YTD 2020 was $33.12/bbl and $26.35/bbl lower relative to Q2/2019 and YTD 2019 compared to a $43.03/bbl and $32.49/bbl decrease in the WCS benchmark price over the same periods. Our realized heavy oil price did not decrease as much as WCS benchmark pricing as we optimized production levels and the timing of deliveries during 2020 which achieved stronger price realizations.

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 $12.79/bbl in Q2/2020 or 33% of WTI (expressed in Canadian dollars) compared to $17.57/bbl or 22% of WTI (expressed in Canadian dollars) in Q2/2019. Our YTD 2020 realized NGL price was $13.56/bbl or 27% of WTI (expressed in Canadian dollars) compared to $20.34/bbl or 27% of WTI (expressed in Canadian dollars) in YTD 2019. Our realized NGL price was higher as a percentage of WTI in Q2/2020 compared to Q2/2019 as the decrease in the underlying product prices wasn't as large relative to the decrease in WTI over the same period.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price was $1.86/mcf for Q2/2020 and $1.94/mcf in YTD 2020 compared to $1.16/mcf in Q2/2019 and $1.77/mcf in YTD 2019. The increase in our realized natural gas price in Canada is consistent with the increase in the AECO benchmark price over the same periods. In the U.S., our realized natural gas price was US$1.72/mcf for Q2/2020 and US$1.83/mcf in YTD 2020 compared to US$2.59/mcf in Q2/2019 and US$2.78/mcf in YTD 2019. Our realized natural gas price in the U.S. is consistent with the NYMEX benchmark in both periods of 2020 and 2019.

Petroleum and Natural Gas Sales

	Three Months Ended June 30					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 42,231**	**$ 61,043**	**$ 103,274**	$ 141,827	$ 153,504	$ 295,331
Heavy oil	**24,003**	**—**	**24,003**	146,038	—	146,038
NGL	**847**	**8,035**	**8,882**	1,757	15,808	17,565
Total oil sales	**67,081**	**69,078**	**136,159**	289,622	169,312	458,934
Natural gas sales	**6,244**	**10,286**	**16,530**	5,076	17,990	23,066
Total petroleum and natural gas sales	**73,325**	**79,364**	**152,689**	294,698	187,302	482,000
Blending and other expense	**(5,460)**	**—**	**(5,460)**	(20,890)	—	(20,890)
Total sales, net of blending and other expense	**$ 67,865**	**$ 79,364**	**$ 147,229**	$ 273,808	$ 187,302	$ 461,110

	Six Months Ended June 30					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 151,314**	**$ 182,198**	**$ 333,512**	$ 274,195	$ 302,419	$ 576,614
Heavy oil	**99,846**	**—**	**99,846**	263,724	—	263,724
NGL	**2,196**	**16,877**	**19,073**	5,198	36,610	41,808
Total oil sales	**253,356**	**199,075**	**452,431**	543,117	339,029	882,146
Natural gas sales	**14,813**	**22,059**	**36,872**	15,620	37,658	53,278
Total petroleum and natural gas sales	**268,169**	**221,134**	**489,303**	558,737	376,687	935,424
Blending and other expense	**(26,817)**	**—**	**(26,817)**	(37,678)	—	(37,678)
Total sales, net of blending and other expense	**$ 241,352**	**$ 221,134**	**$ 462,486**	$ 521,059	$ 376,687	$ 897,746

Total sales, net of blending and other expense, of $147.2 million for Q2/2020 decreased $313.9 million from $461.1 million reported for Q2/2019 while total sales, net of blending and other expense, of $462.5 million for YTD 2020 decreased $435.3 million from $897.7 million in YTD 2019. The decrease in total sales in both periods of 2020 is a result of lower realized pricing as a result of the decrease in benchmark pricing along with lower production relative to the comparative periods of 2019.

In Canada, total sales, net of blending and other expense, was $67.9 million for Q2/2020 which is a decrease of $205.9 million from Q2/2019. Total petroleum and natural gas sales decreased due lower realized pricing combined with lower production in Q2/2020 relative to Q2/2019. Our average realized price of $19.79/boe for Q2/2020 was lower than $51.36/boe for Q2/2019 due to the decrease in benchmark pricing in Canada and resulted in a $108.3 million decrease in total sales, net of blending and other expense. Production in Canada was 20,889 boe/d lower in Q2/2020 which resulted in a $97.6 million decrease in total sales, net of blending and other expense relative to Q2/2019. Lower production and the decrease in benchmark prices resulted in our total sales, net of blending and other expense, decreasing to $241.4 million in YTD 2020 from $521.1 million in YTD 2019.

In the U.S., petroleum and natural gas sales were $79.4 million for Q2/2020 which is a decrease of $107.9 million from $187.3 million reported for Q2/2019. Our realized price for Q2/2020 was $26.64/boe lower than Q2/2019 and resulted in a $84.4 million decrease in total petroleum and natural gas sales. Lower completion activity on our lands during YTD 2020 resulted in a 5,005 boe/d decrease in production in Q2/2020 and a $23.5 million decrease in total sales, net of blending and other expense relative to Q2/2019. Lower production and realized pricing in YTD 2020 resulted in petroleum and natural gas sales of $221.1 million which was $155.6 million lower than $376.7 million for YTD 2019.

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, 2020 and 2019.

	Three Months Ended June 30					
	2020			2019		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 6,157**	**$ 22,999**	**$ 29,156**	$ 30,936	$ 55,681	$ 86,617
Average royalty rate[(1)]	**9.1 %**	**29.0 %**	**19.8 %**	11.3 %	29.7 %	18.8 %
Royalties per boe	**$ 1.80**	**$ 7.26**	**$ 4.42**	$ 5.80	$ 15.37	$ 9.67

	Six Months Ended June 30					
	2020			2019		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 21,675**	**$ 64,201**	**$ 85,876**	$ 56,120	$ 111,822	$ 167,942
Average royalty rate[(1)]	**9.0 %**	**29.0 %**	**18.6 %**	10.8 %	29.7 %	18.7 %
Royalties per boe	**$ 2.38**	**$ 9.94**	**$ 5.52**	$ 5.23	$ 15.27	$ 9.30

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

Royalties for Q2/2020 were $29.2 million or 19.8% of total sales, net of blending and other expense compared to $86.6 million or 18.8% in Q2/2019. Total royalties in YTD 2020 were $85.9 million or 18.6% of total sales, net of blending and other expense compared to $167.9 million or 18.7% in YTD 2019. Total royalty expense is lower in Q2/2020 and YTD 2020 due to lower total sales, net of blending and other expense, relative to the same periods of 2019. Our royalty rate of 19.8% for Q2/2020 was slightly higher than 18.8% for Q2/2019 as a higher proportion of our total sales, net of blending and other expense, were from our U.S. properties in Q2/2020 relative to the same period of 2019. Our royalty rate of 18.6% for YTD 2020 was consistent with 18.7% in YTD 2019.

Our Canadian royalty rate of 9.1% for Q2/2020 and 9.0% for YTD 2020 was lower than 11.3% for Q2/2019 and 10.8% for YTD 2019 due to lower benchmark commodity prices which resulted in a lower royalty rate on our Canadian properties in 2020 relative to 2019. In the U.S., royalties for Q2/2020 and YTD 2020 averaged 29.0% of total sales which is consistent with the same periods of 2019 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

Our average royalty rate of 18.6% for YTD 2020 is consistent with our revised annual guidance of approximately 18.5% for 2020.

Operating Expense

	Three Months Ended June 30					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 49,162**	**$ 24,518**	**$ 73,680**	$ 73,877	$ 26,597	$ 100,474
Operating expense per boe	**$ 14.33**	**$ 7.74**	**$ 11.17**	$ 13.86	$ 7.34	$ 11.22

	Six Months Ended June 30					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 128,084**	**$ 50,066**	**$ 178,150**	$ 147,979	$ 52,787	$ 200,766
Operating expense per boe	**$ 14.08**	**$ 7.75**	**$ 11.45**	$ 13.79	$ 7.21	$ 11.12

Operating expense was $73.7 million ($11.17/boe) for Q2/2020 and $178.2 million ($11.45/boe) for YTD 2020 compared to $100.5 million ($11.22/boe) in Q2/2019 and $200.8 million ($11.12/boe) in YTD 2019. The decrease in total operating expense can be attributed to a decrease in production and our cost savings initiatives as per boe operating expense for Q2/2020 and YTD 2020 was relatively consistent with the comparative periods of 2019.

In Canada, operating expense was $49.2 million ($14.33/boe) for Q2/2020 and $128.1 million ($14.08/boe) for YTD 2020 compared to $73.9 million ($13.86/boe) for Q2/2019 and $148.0 million ($13.79/boe) in YTD 2019. Total operating expense in Canada has decreased with lower production in both periods of 2020 compared to 2019. With the decrease in production we expected per unit costs to increase, but due to our cost savings initiatives in Canada per unit operating expense of $14.33/boe for Q2/2020 and $14.08/boe for YTD 2020 was only slightly higher than the comparative periods of 2019.

U.S. operating expense was $24.5 million ($7.74/boe) for Q2/2020 and $50.1 million ($7.75/boe) for YTD 2020 compared to $26.6 million ($7.34/boe) for Q2/2019 and $52.8 million ($7.21/boe) in YTD 2019. Lower total operating expense is primarily a result of lower U.S. production in Q2/2020 and YTD 2020 relative to the comparative periods of 2019. Expressed in U.S. dollars, per unit operating expense was US$5.58/boe in Q2/2020 and US$5.68/boe in YTD 2020 which is relatively consistent with US $5.49/boe for Q2/2019 and US$5.41/boe in YTD 2019.

Operating expense of $11.45/boe for YTD 2020 is consistent with our expectations and slightly below our annual guidance range of $11.75 - $12.50/boe for 2020 as we had higher operating cost production shut-in for a portion of 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, 2020 and 2019.

	Three Months Ended June 30					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 5,031**	**$ —**	**$ 5,031**	$ 11,869	$ —	$ 11,869
Transportation expense per boe	**$ 1.47**	**$ —**	**$ 0.76**	$ 2.23	$ —	$ 1.33

	Six Months Ended June 30					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 15,373**	**$ —**	**$ 15,373**	$ 25,199	$ —	$ 25,199
Transportation expense per boe	**$ 1.69**	**$ —**	**$ 0.99**	$ 2.35	$ —	$ 1.40

Transportation expense was $5.0 million ($0.76/boe) for Q2/2020 and $15.4 million ($0.99/boe) for YTD 2020 compared to $11.9 million ($1.33/boe) in Q2/2019 and $25.2 million ($1.40/boe) in YTD 2019. The decrease in total transportation expense in both periods of 2020 relative to 2019 is primarily the result of lower crude oil shipments after we shut-in light and heavy oil production in Canada due to the decline in crude oil prices during 2020. Optimization of light and heavy oil deliveries in Canada resulted in lower per boe transportation expense for both periods of 2020 relative to the same periods of 2019. Transportation expense of $0.99 per boe for YTD 2020 is consistent with expectations and our annual guidance of $0.95 to $1.05 per boe for 2020.

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 $5.5 million for Q2/2020 and $26.8 million for YTD 2020 compared to $20.9 million for Q2/2019 and $37.7 million for YTD 2019. Lower blending and other expense in both periods of 2020 compared to 2019 reflects lower heavy oil sales after we shut-in heavy oil production in response to the decline in commodity prices in Q2/2020.

Financial Derivatives

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. 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, 2020 and 2019.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2020**	2019	Change	**2020**	2019	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ 13,524**	$ 12,501	$ 1,023	**$ 40,169**	$ 30,313	$ 9,856
Natural gas	**378**	504	(126)	**589**	1,470	(881)
Interest and financing	**(278)**	(12)	(266)	**(284)**	24	(308)
Total	**$ 13,624**	$ 12,993	$ 631	**$ 40,474**	$ 31,807	$ 8,667
Unrealized financial derivatives gain (loss)						
Crude oil	**$ (71,936)**	$ 13,524	$ (85,460)	**$ 27,873**	$ (37,642)	$ 65,515
Natural gas	**1,181**	1,230	(49)	**1,059**	(350)	1,409
Interest and financing	**204**	(81)	285	**(474)**	(596)	122
Equity total return swap ("Equity TRS")	**1,265**	—	1,265	**(1,749)**	—	(1,749)
Total	**$ (69,286)**	$ 14,673	$ (83,959)	**$ 26,709**	$ (38,588)	$ 65,297
Total financial derivatives gain (loss)						
Crude oil	**$ (58,412)**	$ 26,025	$ (84,437)	**$ 68,042**	$ (7,329)	$ 75,371
Natural gas	**1,559**	1,734	(175)	**1,648**	1,120	528
Interest and financing	**(74)**	(93)	19	**(758)**	(572)	(186)
Equity TRS	**1,265**	—	1,265	**(1,749)**	—	(1,749)
Total	**$ (55,662)**	$ 27,666	$ (83,328)	**$ 67,183**	$ (6,781)	$ 73,964

We recorded total financial derivative losses of $55.7 million for Q2/2020 and gains of $67.2 million for YTD 2020. Realized financial derivatives gains of $13.6 million for Q2/2020 and $40.5 million for YTD 2020 are primarily a result of the market prices for crude oil settling at levels below those set in our contracts. The unrealized loss of $69.3 million for Q2/2020 and the unrealized gain of $26.7 million for YTD 2020 is primarily due to fluctuations in future commodity prices and revaluation of contracts in place at June 30, 2020 compared to the value of contracts in place at the start of the respective periods.

Realized gains on crude oil financial derivatives of $13.5 million in Q2/2020 and $40.2 million in YTD 2020 are primarily a result of market prices for WTI settling at levels below the prices set in our contracts outstanding during the periods. Our natural gas financial derivatives generated gains of $0.4 million in Q2/2020 and $0.6 million in YTD 2020. These gains were a result of the NYMEX index for both periods of 2020 averaging less than the fixed price on our NYMEX contracts in place. We also recorded realized losses of $0.3 million in Q2/2020 and YTD 2020 as the Canadian Dollar Offered Rate settled below the fixed interest rate set in a swap contract we acquired in 2018.

Unrealized losses of $69.3 million in Q2/2020 and gains of $26.7 million for YTD 2020 reflect the volatility in forecasted crude oil pricing used to revalue our contracts in place at June 30, 2020 relative to March 31, 2020 and December 31, 2019 along with the valuation of new contracts entered during the period. Forecasted crude oil prices at June 30, 2020 were higher relative to March 31, 2020 and lower relative to December 31, 2019. The fair value of our financial derivative contracts resulted in a net asset of $23.5 million at June 30, 2020 compared to a net asset of $92.8 million at March 31, 2020 and a net liability of $3.2 million at December 31, 2019.

We had the following commodity financial derivative contracts as at July 29, 2020.

	Period	Volume	Price/Unit[1]	Index
Oil				
WCS Stream[8]	July 2020	8,000 bbl/d	$27.15/bbl	Blended
WCS Stream[8]	August 2020	5,000 bbl/d	$32.05/bbl	Blended
Basis Swap	July 2020 to Dec 2020	6,500 bbl/d	WTI less US$16.27/bbl	WCS
Basis Swap	Jan 2021 to Dec 2021	4,000 bbl/d	WTI less US$14.26/bbl	WCS
MSW Stream[7]	July 2020	11,695 bbl/d	$27.17/bbl	Blended
MSW Stream[7]	August 2020	5,000 bbl/d	$42.28/bbl	Blended
Basis Swap	July 2020 to Dec 2020	5,000 bbl/d	WTI less US$6.15/bbl	MSW
Basis Swap[9]	Jan 2021 to Dec 2021	2,000 bbl/d	WTI less US$5.95/bbl	MSW
Fixed - Sell	July 2020	4,000 bbl/d	US$24.73/bbl	WTI
Fixed - Sell	July 2020	9,500 bbl/d	$36.32/bbl	WTI-CAD
Fixed - Sell	August 2020	5,000 bbl/d	US$36.30/bbl	WTI
Fixed - Sell	August 2020	5,000 bbl/d	$48.55/bbl	WTI-CAD
Fixed - Sell	July 2020 to Dec 2020	6,000 bbl/d	US$43.50/bbl	WTI
Fixed - Sell	October 2020 to Dec 2020	2,000 bbl/d	US$40.61/bbl	WTI
3-way option[2]	July 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$56.00/US$61.35	WTI
3-way option[2]	July 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$57.00/US$60.00	WTI
3-way option[2]	July 2020 to Dec 2020	4,500 bbl/d	US$50.00/US$57.00/US$62.00	WTI
3-way option[2]	July 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$58.00/US$62.00	WTI
3-way option[2]	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.50	WTI
3-way option[2]	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.83	WTI
3-way option[2]	July 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI
3-way option[2]	July 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI
3-way option[2]	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI
3-way option[2]	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI
3-way option[2]	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI
3-way option[2]	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI
3-way option[2]	July 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	WTI
3-way option[2][9]	Jan 2021 to Dec 2021	5,000 bbl/d	US$35.00/US$45.00/US$55.00	WTI
Swaption[3]	Jan 2021 to Dec 2021	3,000 bbl/d	US$64.50/bbl	Brent
Swaption[4]	Jan 2021 to Dec 2021	3,000 bbl/d	US$70.00/bbl	Brent
Swaption[4]	Jan 2021 to Dec 2021	3,000 bbl/d	US$60.75/bbl	WTI
Swaption[6][9]	Jan 2022 to Dec 2022	5,000 bbl/d	US$53.00/bbl	WTI
Natural Gas				
Fixed - Sell	July 2020 to Dec 2020	10,500 GJ/d	$2.01/GJ	AECO 7A
Fixed - Sell	Jan 2021 to Dec 2021	13,000 GJ/d	$2.29/GJ	AECO 7A
Fixed - Sell	July 2020 to Dec 2020	2,500 GJ/d	$2.29/GJ	AECO 5A
Fixed - Sell [9]	Jan 2021 to Dec 2021	2,500 GJ/d	$2.40/GJ	AECO 5A
Fixed - Sell	Oct 2020 to Dec 2020	5,500 mmbtu/d	US$2.64/mmbtu	NYMEX
Fixed - Sell	Jan 2021 to Dec 2021	12,000 mmbtu/d	US$2.70/mmbtu	NYMEX
3-way option[2]	July 2020 to Dec 2020	5,000 mmbtu/d	US$2.25/US$2.60/US$2.85	NYMEX
Swaption[5]	Jan 2021 to Dec 2021	5,000 mmbtu/d	US$2.90/mmbtu	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$58.00/US$62.00 contract, Baytex receives WTI plus US$8.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$58.00/bbl when WTI is between US$50.00/bbl and US$58.00/bbl; Baytex receives the market price when WTI is between US$58.00/bbl and US$62.00/bbl; and Baytex receives US$62.00/bbl when WTI is above US$62.00/bbl.

(3) For these contracts, the counterparty has the right, if exercised on September 30, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

(4) For these contracts, the counterparty has the right, if exercised on December 31, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

(5) For these contracts, the counterparty has the right, if exercised on December 23, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

(6) *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.*
(7) *For these contracts, the contract price per unit is the sum of the average WTI price for the period and the average of the Edmonton SW blend differential (the average of TMX SW 1a index as determined by NGX and the NE Monthly Index for physical SW as determined by Net Energy), converted to CAD at the noon day average rate.*
(8) *For these contracts, the contract price per unit is the sum of the average WTI price for the period and the average of the Western Canadian Select blend differential (the average of the Natural Gas Exchange Inc's WCS Index Differential and the Net Energy Inc.'s WCS Index Differential), converted to CAD at the noon day average rate.*
(9) *Contracts entered subsequent to June 30, 2020.*

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, 2020 and 2019.

	Three Months Ended June 30					
	2020			2019		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**37,691**	**34,817**	**72,508**	58,580	39,822	98,402
Operating netback:						
Total sales, net of blending and other expense	**$ 19.79**	**$ 25.05**	**$ 22.31**	$ 51.36	$ 51.69	$ 51.49
Less:						
Royalties	**(1.80)**	**(7.26)**	**(4.42)**	(5.80)	(15.37)	(9.67)
Operating expense	**(14.33)**	**(7.74)**	**(11.17)**	(13.86)	(7.34)	(11.22)
Transportation expense	**(1.47)**	**—**	**(0.76)**	(2.23)	—	(1.33)
Operating netback	**$ 2.19**	**$ 10.05**	**$ 5.96**	$ 29.47	$ 28.98	$ 29.27
Realized financial derivatives gain	**—**	**—**	**2.06**	—	—	1.45
Operating netback after financial derivatives	**$ 2.19**	**$ 10.05**	**$ 8.02**	$ 29.47	$ 28.98	$ 30.72

	Six Months Ended June 30					
	2020			2019		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**49,976**	**35,503**	**85,479**	59,296	40,455	99,751
Operating netback:						
Total sales, net of blending and other expense	**$ 26.53**	**$ 34.22**	**$ 29.73**	$ 48.55	$ 51.44	$ 49.72
Less:						
Royalties	**(2.38)**	**(9.94)**	**(5.52)**	(5.23)	(15.27)	(9.30)
Operating expense	**(14.08)**	**(7.75)**	**(11.45)**	(13.79)	(7.21)	(11.12)
Transportation expense	**(1.69)**	**—**	**(0.99)**	(2.35)	—	(1.40)
Operating netback	**$ 8.38**	**$ 16.53**	**$ 11.77**	$ 27.18	$ 28.96	$ 27.90
Realized financial derivatives gain	**—**	**—**	**2.60**	—	—	1.76
Operating netback after financial derivatives	**$ 8.38**	**$ 16.53**	**$ 14.37**	$ 27.18	$ 28.96	$ 29.66

Our operating netback after financial derivatives was $8.02/boe for Q2/2020 and $14.37/boe for YTD 2020 compared to $30.72/boe for Q2/2019 and $29.66/boe for YTD 2019. Operating netback was lower in both periods of 2020 relative to the comparative periods of 2019 due to the significant decrease in benchmark pricing which resulted in lower per unit sales, net of royalties, in Canada and the U.S. Total operating and transportation expense of $11.93/boe in Q2/2020 and $12.44/boe in YTD 2020 reflects our cost savings initiatives and resulted lower costs relative to $12.55/boe in Q2/2019 and $12.52/boe in YTD 2019. Lower operating netback in both periods of 2020 was partially offset by realized gains on financial derivatives that were $0.61/boe higher in Q2/2020 and $0.84/boe higher in YTD 2020 relative to the same periods of 2019.

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, 2020 and 2019.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2020**	2019	Change	**2020**	2019	Change
Gross general and administrative expense	**$ 7,476**	$ 12,655	$ (5,179)	**$ 19,364**	$ 28,274	$ (8,910)
Overhead recoveries	**(38)**	(1,149)	1,111	**(2,151)**	(2,632)	481
General and administrative expense	**$ 7,438**	$ 11,506	$ (4,068)	**$ 17,213**	$ 25,642	$ (8,429)
General and administrative expense per boe	**$ 1.13**	$ 1.28	$ (0.15)	**$ 1.11**	$ 1.42	$ (0.31)

G&A expense was $7.4 million ($1.13/boe) for Q2/2020 and $17.2 million ($1.11/boe) in YTD 2020 compared to $11.5 million ($1.28/boe) for Q2/2019 and $25.6 million ($1.42/boe) for YTD 2019.

G&A expense for Q2/2020 and YTD 2020 was lower relative to Q2/2019 and YTD 2019 primarily due to lower staffing costs after we reduced employee salaries and director compensation by 10% on April 1, 2020 along with $2.0 million of benefit associated with the Canada Emergency Wage Subsidy ("CEWS") included in Q2/2020. G&A per boe was lower in Q2/2020 and YTD 2020 despite lower production relative to comparative periods of 2019 which reflects our ongoing cost savings initiatives and the benefit of the CEWS.

G&A expense of $17.2 million ($1.11/boe) in YTD 2020 is below our annual guidance of $38 million ($1.30/boe) as YTD 2020 production exceeded the high end of our guidance range, and also reflects our continued cost saving initiatives along with government incentives received during Q2/2020. Our annual guidance of $38 million ($1.30/boe) reflects the benefit of the CEWS which has been extended until Q4/2020.

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 and 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, 2020 and 2019.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2020**	2019	Change	**2020**	2019	Change
Interest on credit facilities	**$ 4,248**	$ 5,109	$ (861)	**$ 8,383**	$ 10,521	$ (2,138)
Interest on long-term notes	**23,015**	22,825	190	**47,288**	45,427	1,861
Interest on lease obligations	**124**	158	(34)	**$ 251**	$ 328	(77)
Cash interest	**$ 27,387**	$ 28,092	$ (705)	**$ 55,922**	$ 56,276	$ (354)
Accretion of debt issue costs	**665**	1,051	(386)	**5,107**	2,146	2,961
Accretion of asset retirement obligations	**2,178**	3,398	(1,220)	**5,109**	6,861	(1,752)
Early redemption expense	**—**	—	—	**3,312**	—	3,312
Financing and interest expense	**$ 30,230**	$ 32,541	$ (2,311)	**$ 69,450**	$ 65,283	$ 4,167
Cash interest per boe	**$ 4.15**	$ 3.14	$ 1.01	**$ 3.59**	$ 3.12	$ 0.47
Financing and interest expense per boe	**$ 4.58**	$ 3.63	$ 0.95	**$ 4.46**	$ 3.62	$ 0.84

Financing and interest expense was $30.2 million in Q2/2020 and $69.5 million in YTD 2020 compared to $32.5 million in Q2/2019 and $65.3 million in YTD 2019.

Cash interest of $27.4 million ($4.15/boe) in Q2/2020 and $55.9 million ($3.59/boe) in YTD 2020 is slightly lower than $28.1 million ($3.14/boe) in Q2/2019 and $56.3 million ($3.12/boe) in YTD 2019. On February 5, 2020, we issued US$500 million principal amount of 8.75% senior unsecured notes. Proceeds from this issuance were used to reduce amounts outstanding on our credit facilities prior to the early redemption of the US$400 million principal amount of 5.125% senior unsecured notes on February 20, 2020 and the early redemption of the $300 million principal amount of the 6.625% senior unsecured notes on March 5, 2020. Interest on our credit facilities was also lower in both periods of 2020 due to a lower weighted average borrowing rate on amounts outstanding relative to 2019. The weighted average interest rate on our credit facilities was 2.7% in YTD 2020 compared to 3.6% in YTD 2019.

Financing and interest expense for YTD 2020 includes the accelerated amortization of debt issue costs and $3.3 million of early redemption expense associated with the $300 million principal amount of 6.625% senior unsecured notes which were redeemed at 101.104% of the principal amount on March 5, 2020.

Cash interest expense of $3.59/boe is slightly below our annual guidance of $3.84/boe as production in YTD 2020 exceeded the high end of our annual guidance range. We continue to expect cash financing and interest expense of $112 million ($3.84/boe) for 2020.

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 $1.8 million for Q2/2020 and $2.1 million in YTD 2020 which is lower than $4.7 million for Q2/2019 and $6.5 million in YTD 2019 due to less acreage expiring in both periods of 2020 relative to 2019.

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, 2020 and 2019.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2020**	2019	Change	**2020**	2019	Change
Depletion	**$ 102,622**	$ 185,232	$ (82,610)	**$ 282,040**	$ 370,076	$ (88,036)
Depreciation	**1,918**	540	1,378	**3,886**	1,050	2,836
Depletion and depreciation	**$ 104,540**	$ 185,772	$ (81,232)	**$ 285,926**	$ 371,126	$ (85,200)
Depletion and depreciation per boe	**$ 15.84**	$ 20.75	$ (4.91)	**$ 18.38**	$ 20.56	$ (2.18)

Depletion and depreciation expense was $104.5 million ($15.84/boe) for Q2/2020 and $285.9 million ($18.38/boe) in YTD 2020 compared to $185.8 million ($20.75/boe) for Q2/2019 and $371.1 million ($20.56/boe) for YTD 2019. Total depletion and depreciation expense and the depletion rate per boe were lower in both periods of 2020 relative to the comparative periods of 2019 due to lower production in 2020 along with $2.6 billion of impairment write-downs recorded in Q1/2020 which reduced the depletable base of our oil and gas properties.

Impairment

We did not identify indicators of impairment or impairment reversal for any of our cash generating units ("CGU") at June 30, 2020.

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 all of our CGUs. We recorded total impairments of $2.7 billion in Q1/2020 as the carrying value of the E&E assets and oil and gas properties of our CGUs exceeded their estimated recoverable amounts. The total impairment includes $2.6 billion related to the CGUs comprising oil and gas properties and $0.1 billion related to the CGUs comprising E&E assets.

The recoverable amount of each CGU was 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.

	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

This data is combined with assumptions relating to long-term prices, inflation rates and exchange rates together with estimates of transportation costs and pricing of competing fuels to forecast long-term energy prices, consistent with external sources of information. The prices and costs subsequent to 2029 have been adjusted for inflation at an annual rate of 2.0%.

The following table summarizes the recoverable amount and impairment at March 31, 2020 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	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

Share-Based Compensation Expense

Share-based compensation ("SBC") expense includes expense associated with our Share Award Incentive Plan and our Incentive Award 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 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 $3.0 million for Q2/2020 and $5.8 million for YTD 2020 compared to $5.0 million for Q2/2019 and $10.8 million for YTD 2019. SBC expense is lower in both periods of 2020 as the total value of awards granted in 2020 was lower than prior years. The total expense for YTD 2020 is comprised of non-cash compensation expense of $4.6 million related to the Share Award Incentive Plan and cash compensation expense of $1.1 million related to the Incentive Award Plan.

Foreign Exchange

Unrealized foreign exchange gains and losses represent the change in value of the long-term notes and credit facilities denominated in U.S. dollars. The long-term notes and credit facilities are translated to Canadian dollars on the balance sheet date using the closing CAD/USD exchange rate. When the Canadian dollar strengthens against the U.S. dollar at the end of the current period compared to the previous period an unrealized gain is recorded and conversely when the Canadian dollar weakens at the end of the current period compared to the previous period an unrealized loss is recorded. 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)	**2020**	2019	Change	**2020**	2019	Change
Unrealized foreign exchange (gain) loss	**$ (45,516)**	$ (25,318)	$ (20,198)	**$ 54,005**	$ (52,259)	$ 106,264
Realized foreign exchange (gain) loss	**(457)**	639	(1,096)	**(86)**	44	(130)
Foreign exchange (gain) loss	**$ (45,973)**	$ (24,679)	$ (21,294)	**$ 53,919**	$ (52,215)	$ 106,134
CAD/USD exchange rates:						
At beginning of period	**1.4120**	1.3360		**1.2965**	1.3646	
At end of period	**1.3616**	1.3091		**1.3616**	1.3091	

We recorded 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. This compares to an unrealized foreign exchange gain of $25.3 million in Q2/2019 due to the strengthening of the Canadian dollar relative to the U.S. dollar over Q2/2019.

We recorded an unrealized foreign exchange loss of $54.0 million for YTD 2020 due to the weakening of the Canadian dollar relative to the U.S. dollar at June 30, 2020 compared to December 31, 2019. This compares to an unrealized foreign exchange gain of $52.3 million in YTD 2019 due to the strengthening of the Canadian dollar relative to the U.S. dollar at June 30, 2019 relative to December 31, 2018.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange gain of $0.5 million for Q2/2020 and $0.1 million in YTD 2020 compared to a loss of $0.6 million for Q2/2019 and $44 thousand in YTD 2019.

Income Taxes

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2020**	2019	Change	**2020**	2019	Change
Current income tax expense	**$ 89**	$ 495	$ (406)	**$ 558**	$ 1,090	$ (532)
Deferred income tax expense (recovery)	**21,002**	(1,555)	22,557	**(262,177)**	(16,040)	(246,137)
Total income tax expense (recovery)	**$ 21,091**	$ (1,060)	$ 22,151	**$ (261,619)**	$ (14,950)	$ (246,669)

Current income tax expense was $0.1 million for Q2/2020 and $0.6 million for YTD 2020 compared to $0.5 million for Q2/2019 and $1.1 million in YTD 2019. Current income tax was lower in both periods of 2020 due to lower state tax owed on our U.S. operations relative to the comparative periods of 2019.

We recorded a deferred income tax expense of $21.0 million for Q2/2020 compared to a recovery of $1.6 million for Q2/2019. The increased expense is primarily related to final regulations published on April 7, 2020 addressing "anti-hybrid" rules under section 267A of the U.S. tax code. Pursuant to these regulations, the Company is no longer entitled to certain tax benefits previously recognized during 2019 and Q1/2020. Accordingly, a non-cash charge against deferred income taxes of $20.2 million has been recorded in the three months ended June 30, 2020.

We recorded a deferred income tax recovery of $262.2 million for YTD 2020 compared to $16.0 million for YTD 2019. Our deferred income tax recovery was higher in YTD 2020 primarily due to the impairment of assets recorded in Q1/2020.

As disclosed in the 2019 annual financial statements, certain indirect subsidiaries received reassessments from the Canada Revenue Agency (the "CRA") that deny $591 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, 2020 and 2019 are set forth in the following table.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2020**	2019	Change	**2020**	2019	Change
Petroleum and natural gas sales	**$ 152,689**	$ 482,000	$ (329,311)	**$ 489,303**	$ 935,424	$ (446,121)
Royalties	**(29,156)**	(86,617)	57,461	**(85,876)**	(167,942)	82,066
Revenue, net of royalties	**123,533**	395,383	(271,850)	**403,427**	767,482	(364,055)
Expenses						
Operating	**(73,680)**	(100,474)	26,794	**(178,150)**	(200,766)	22,616
Transportation	**(5,031)**	(11,869)	6,838	**(15,373)**	(25,199)	9,826
Blending and other	**(5,460)**	(20,890)	15,430	**(26,817)**	(37,678)	10,861
Operating netback	**$ 39,362**	$ 262,150	$ (222,788)	**$ 183,087**	$ 503,839	$ (320,752)
General and administrative	**(7,438)**	(11,506)	4,068	**(17,213)**	(25,642)	8,429
Cash financing and interest	**(27,387)**	(28,092)	705	**(55,922)**	(56,276)	354
Realized financial derivatives gain	**13,624**	12,993	631	**40,474**	31,807	8,667
Realized foreign exchange gain (loss)	**457**	(639)	1,096	**86**	(44)	130
Other income (expense)	**(24)**	1,719	(1,743)	**2,007**	4,306	(2,299)
Current income tax expense	**(89)**	(495)	406	**(558)**	(1,090)	532
Share based compensation	**(618)**	—	(618)	**(1,139)**	—	(1,139)
Adjusted funds flow	**$ 17,887**	$ 236,130	$ (218,243)	**$ 150,822**	$ 456,900	$ (306,078)
Exploration and evaluation	**(1,831)**	(4,685)	2,854	**(2,091)**	(6,529)	4,438
Depletion and depreciation	**(104,540)**	(185,772)	81,232	**(285,926)**	(371,126)	85,200
Share based compensation	**(2,375)**	(5,001)	2,626	**(4,637)**	(10,844)	6,207
Non-cash financing and accretion	**(2,843)**	(4,449)	1,606	**(13,528)**	(9,007)	(4,521)
Unrealized financial derivatives (loss) gain	**(69,286)**	14,673	(83,959)	**26,709**	(38,588)	65,297
Unrealized foreign exchange gain (loss)	**45,516**	25,318	20,198	**(54,005)**	52,259	(106,264)
Gain on dispositions	**11**	1,057	(1,046)	**148**	1,057	(909)
Impairment	**—**	—	—	**(2,716,349)**	—	(2,716,349)
Deferred income tax (expense) recovery	**(21,002)**	1,555	(22,557)	**262,177**	16,040	246,137
Net income (loss) for the period	**$ (138,463)**	$ 78,826	$ (217,289)	**$(2,636,680)**	$ 90,162	$(2,726,842)

We generated adjusted funds flow of $17.9 million for Q2/2020 and $150.8 million for YTD 2020 compared to $236.1 million reported in Q2/2019 and $456.9 million for YTD 2019. The decrease in adjusted funds flow in both periods of 2020 is primarily due to the decline in commodity benchmark prices which resulted in a $256.4 million decrease in revenue, net of royalties and blending and other expense for Q2/2020 and a $353.2 million decrease for YTD 2020. This decrease in adjusted funds flow in 2020 relative to 2019 was mitigated by our costs savings initiatives which resulted in a $37.7 million drop in operating, transportation, and general and administrative expenses for Q2/2020 and $40.9 million for YTD 2020.

We reported a net loss of $138.5 million for Q2/2020 and $2.6 billion for YTD 2020 compared to net income of $78.8 million for Q2/2019 and $90.2 million for YTD 2019. The net loss for Q2/2020 was primarily a result of lower commodity prices and shut-in production which resulted in a $218.2 million decrease in adjusted funds flow compared to Q2/2019 and was the main contributor to the $217.3 million decrease in net income over the same period. The net loss of $2.6 billion for YTD 2020 was $2.7 billion lower than net income of $90.2 million for YTD 2019 due to the $2.7 billion impairment of our oil and gas properties in Q1/2020 which resulted from the significant decrease in forecasted oil and natural gas prices.

Other Comprehensive Income (Loss)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets which is not recognized in profit or loss. The foreign currency translation loss of $53.5 million for Q2/2020 and the gain of $120.5 million for YTD 2020 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the change of the Canadian dollar relative to the U.S. dollar at June 30, 2020 compared to March 31, 2020 and December 31, 2019. The CAD/USD exchange rate was 1.3616 CAD/USD as at June 30, 2020 compared to 1.4120 CAD/USD at March 31, 2020 and 1.2965 CAD/USD at December 31, 2019.

Capital Expenditures

Capital expenditures for the three and six months ended June 30, 2020 and 2019 are summarized as follows.

	Three Months Ended June 30					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 8**	**$ 6,768**	**$ 6,776**	$ 54,056	$ 35,926	$ 89,982
Facilities	**2,693**	**—**	**2,693**	8,527	1,920	10,447
Land, seismic and other	**228**	**155**	**383**	5,676	141	5,817
Total exploration and development	**$ 2,929**	**$ 6,923**	**$ 9,852**	$ 68,259	$ 37,987	$ 106,246
Total acquisitions, net of proceeds from divestitures	**$ (11)**	**$ —**	**$ (11)**	$ 1,647	$ —	$ 1,647

	Six Months Ended June 30					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 99,545**	**$ 59,839**	**$ 159,384**	$ 142,937	$ 81,985	$ 224,922
Facilities	**21,697**	**299**	**21,996**	21,467	4,582	26,049
Land, seismic and other	**4,798**	**451**	**5,249**	8,725	393	9,118
Total exploration and development	**$ 126,040**	**$ 60,589**	**$ 186,629**	$ 173,129	$ 86,960	$ 260,089
Total acquisitions, net of proceeds from divestitures	**$ (51)**	**$ —**	**$ (51)**	$ 1,647	$ —	$ 1,647

Exploration and development expenditures were $9.9 million for Q2/2020 and $186.6 million for YTD 2020 compared to $106.2 million for Q2/2019 and $260.1 million for YTD 2019. Expenditures in Q2/2020 and YTD 2020 were lower than the comparative periods of 2019 as we suspended our operated capital activity in Canada and moderated the pace of development in the U.S. as a result of the sharp decline in crude oil prices in March 2020.

In Canada, we invested $2.9 million on exploration and development activities in Q2/2020 which is $65.3 million lower than $68.3 million in Q2/2019. Exploration and development expenditures of $2.9 million for Q2/2020 were associated with primary development of one of our polymer flood projects at Lloydminster. Drilling and completion operations were suspended after the sharp decline in crude oil prices in March 2020 and we did not drill any wells in our Canadian operations during Q2/2020. Exploration and development expenditures of $126.0 million for YTD 2020 included costs associated with drilling 72 (69.2 net) light oil wells in the Viking, 2 (2.0 net) light oil wells in the Duvernay, 33 (33.0 net) heavy oil wells, 6 (6.0 net) stratigraphic exploration wells and investing $21.7 million on facilities. Exploration and development expenditures of $173.1 million for YTD 2019 included costs associated with 141 (121.2 net) light oil wells, 5 (5.0 net) heavy oil wells and 4 (4.0 net) stratigraphic exploration wells. Total exploration and development costs were lower in YTD 2020 relative to YTD 2019 as we suspended development operations following the sharp decline in crude oil pricing in March 2020.

Total U.S. exploration and development expenditures were $6.9 million for Q2/2020 which is $31.1 million lower than $38.0 million for Q2/2019. Exploration and development expenditures of $6.9 million for Q2/2020 included final completion and equipping costs associated with 17 (4.6 net) wells that were brought on production in April. We moderated the pace of our development operations in the U.S. following the sharp decline in crude oil prices in March 2020 and did not initiate any new drilling or completions operations during Q2/2020. Exploration and development expenditures of $60.6 million for YTD 2020 included costs associated with the drilling of 17 (3.8 net) wells and completion activities on 47 (10.7 net) wells. Development expenditures were lower in YTD 2020 due to lower drilling and completions activity relative to YTD 2019 when we drilled 43 (9.2 net) wells and brought 65 (13.9 net) wells on production and spent $87.0 million.

Our 2020 annual guidance range of $260 - $290 million reflects suspended capital activity in Canada for the remainder of 2020 and a moderated pace of development on our Eagle Ford properties in the U.S. We have the flexibility to increase capital expenditures in Canada if the commodity price environment supports additional development in 2020 but expect to remain within our guidance range.

CAPITAL RESOURCES AND LIQUIDITY

We took action to improve our capital structure and financial liquidity during YTD 2020. On February 5, 2020, we issued US$500 million of senior unsecured notes bearing interest at 8.75% which mature on April 1, 2027. Proceeds from the issuance were used in conjunction with availability on the credit facilities to complete the early redemption of the US$400 million principal amount of 5.125% senior unsecured notes due June 1, 2021 and the $300 million principal amount of 6.625% senior unsecured notes due July 19, 2022. We also negotiated an extension to the maturity of our credit facilities from April 2, 2021 to April 2, 2024. As a result of these actions we do not have any debt maturities until 2024 and we had $363.0 million of undrawn capacity on our credit facilities at June 30, 2020.

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, 2020, our capital structure was comprised of shareholders' capital, long-term notes, trade and other receivable, trade and other payables and the credit facilities.

In response to the collapse in oil prices and the global economic instability related to COVID-19, we have taken additional action to protect our financial liquidity. Our 2020 exploration and development expenditures have been reduced with a suspension of drilling operations in Canada and a moderated pace of development in the U.S. We also shut-in low or negative margin production and have the ability to shut-in additional volumes or quickly restart production in response to further changes in the commodity price environment. We have also reduced salaries for all full time employees and all annual retainers paid to our directors by 10% effective April 1, 2020.

At current forward commodity prices we expect to remain in compliance with the financial covenants applicable to our credit facilities through at least December 31, 2021. A decrease or a sustained period of low commodity prices may result in non-compliance with our financial covenants and reduced liquidity on our existing credit facilities. Non-compliance with the financial covenants in our credit facilities could result in our debt becoming due and payable on demand. Should we anticipate non-compliance we will pro-actively approach our lending syndicate to amend the credit facilities to maintain their availability. There is no certainty that we will be successful in negotiating such amendments.

The capital intensive nature of our operations requires us to maintain adequate sources of liquidity to fund ongoing exploration and development. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties. We believe that our internally generated adjusted funds flow and our existing undrawn 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 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.

At June 30, 2020, net debt of $2.0 billion was $123.2 million higher than $1.9 billion at December 31, 2019. The increase in net debt is primarily the result of a $60.1 million increase in the reported amount of our U.S. dollar denominated net debt due to a weaker Canadian dollar at June 30, 2020 along with exploration and development expenditures that exceeded adjusted funds flow by $35.8 million for YTD 2020. We also incurred total transaction and financing costs of $17.6 million related to refinancing transactions in Q1/2020 including the issuance of the US$500 million senior notes due 2027, the early redemption of the $300 million senior notes due 2022 along with extending the maturity of our credit facilities to 2024.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio calculated on a twelve month trailing basis. At June 30, 2020, our net debt to adjusted funds flow ratio was 3.3 compared to a ratio of 2.1 as at December 31, 2019. The increase in the net debt to adjusted funds flow ratio relative to December 31, 2019 is attributed to lower adjusted funds flow due to lower commodity pricing combined with a $123.2 million increase in net debt at June 30, 2020.

Credit Facilities

At June 30, 2020, the principal amount of credit facilities and letters of credit outstanding was $719.9 million and we had $363.0 million of undrawn capacity under our credit facilities that total approximately $1.1 billion. Our credit facilities include US$575 million of revolving credit facilities and a $300 million non-revolving term loan (collectively, the "Credit Facilities").

On March 3, 2020, we amended our Credit Facilities to extend maturity from April 2, 2021 to April 2, 2024. These facilities 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, plus applicable margins. In the event that Baytex breaches any of the covenants under the Credit Facilities, Baytex may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to shareholders.

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 2.3% for Q2/2020 and 2.7% for YTD 2020 compared to 3.9% for Q2/2019 and 3.6% for YTD 2019.

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at June 30, 2020.

Covenant Description	Position as at June 30, 2020	Covenant
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	**1.0:1.0**	3.5:1.0
Interest Coverage[3] (Minimum Ratio)	**6.6:1.0**	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, 2020, the Company's Senior Secured Debt totaled $719.9 million which includes $704.1 million of principal amounts outstanding and $15.8 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, 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, 2020 was $704.4 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 three months ended June 30, 2020 were $106.5 million.

Long-Term Notes

We have two series of long-term notes outstanding that total $1.2 billion as at June 30, 2020. The long-term notes do not contain any financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts our ability to raise additional debt beyond our existing Credit Facilities and long-term notes unless we maintain a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA to financing and interest expenses on a trailing twelve month basis) of 2.00:1.00. The fixed charge coverage ratio was 6.2:1.0 as at June 30, 2020.

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"), which remain outstanding. 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.

On February 20, 2020, we used a portion of the net proceeds from the issuance of the 8.75% Senior Notes to complete the early redemption of the US$400 million principal amount of the 5.125% senior unsecured notes due June 1, 2021 at par plus accrued interest. The payment at redemption was $530.4 million.

On March 5, 2020, Baytex completed the early redemption of the $300 million principal amount of the 6.625% senior unsecured notes due July 19, 2022 at 101.104% of the principal amount plus accrued interest. The payment at redemption includes principal of $300.0 million plus early redemption expense of $3.3 million.

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, 2020, we issued 2.2 million common shares pursuant to our share-based compensation program. As at July 29, 2020, we had 561.2 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, 2020 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	**$ 167,193**	$ 167,193	$ —	$ —	$ —
Credit facilities[1] [2]	**704,135**	—	—	704,135	—
Long-term notes[2]	**1,225,395**	—	—	544,620	680,775
Interest on long-term notes[3]	**522,472**	90,203	180,405	147,253	104,611
Lease agreements	**12,591**	6,268	5,834	489	—
Processing agreements	**10,321**	4,991	1,406	568	3,356
Transportation agreements	**111,737**	14,885	42,033	31,891	22,928
Total	**$ 2,753,844**	$ 283,540	$ 229,678	$ 1,428,956	$ 811,670

(1) The credit facilities matures 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

($ thousands, except per common share amounts)	**2020**		2019				2018	
	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Petroleum and natural gas sales	**152,689**	336,614	445,895	424,600	482,000	453,424	358,437	436,761
Net income (loss)	**(138,463)**	(2,498,217)	(117,772)	15,151	78,826	11,336	(231,238)	27,412
Per common share - basic	**(0.25)**	(4.46)	(0.21)	0.03	0.14	0.02	(0.42)	0.07
Per common share - diluted	**(0.25)**	(4.46)	(0.21)	0.03	0.14	0.02	(0.42)	0.07
Adjusted funds flow	**17,887**	132,935	232,147	213,379	236,130	220,770	110,828	171,210
Per common share - basic	**0.03**	0.24	0.42	0.38	0.42	0.40	0.20	0.46
Per common share - diluted	**0.03**	0.24	0.42	0.38	0.42	0.40	0.20	0.45
Exploration and development	**9,852**	176,777	153,117	139,085	106,246	153,843	184,162	139,195
Canada	**2,929**	123,110	104,460	96,774	68,259	104,870	125,507	94,477
U.S.	**6,923**	53,667	48,657	42,311	37,987	48,973	58,655	44,718
Acquisitions, net of divestitures	**(11)**	(40)	563	(30)	1,647	—	229	—
Net debt	**1,994,953**	2,051,617	1,871,791	1,971,339	2,028,686	2,175,241	2,265,167	2,112,090
Total assets	**3,267,820**	3,441,040	5,914,083	6,233,875	6,222,190	6,359,157	6,377,198	6,491,303
Common shares outstanding	**560,545**	560,483	558,305	557,972	556,798	555,872	554,060	553,950
Daily production								
Total production (boe/d)	**72,508**	98,452	96,360	94,927	98,402	101,115	98,890	82,412
Canada (boe/d)	**37,691**	62,262	57,794	58,134	58,580	60,018	60,453	45,214
U.S. (boe/d)	**34,817**	36,190	38,566	36,793	39,822	41,097	38,437	37,198
Benchmark prices								
WTI oil (US$/bbl)	**27.85**	46.17	56.96	56.45	59.81	54.90	58.81	69.50
WCS heavy (US$/bbl)	**16.38**	25.65	41.13	44.21	49.14	42.61	19.39	47.25
CAD/USD avg exchange rate	**1.3860**	1.3445	1.3201	1.3207	1.3376	1.3293	1.3215	1.3070
AECO gas ($/mcf)	**1.91**	2.14	2.34	1.04	1.17	1.94	1.94	1.35
NYMEX gas (US$/mmbtu)	**1.72**	1.95	2.50	2.23	2.64	3.15	3.64	2.90
Sales price ($/boe)	**22.31**	35.19	48.25	47.14	51.49	47.98	37.89	55.03
Royalties ($/boe)	**(4.42)**	(6.33)	(8.72)	(8.59)	(9.67)	(8.94)	(8.77)	(12.13)
Operating expense ($/boe)	**(11.17)**	(11.66)	(11.23)	(11.15)	(11.22)	(11.02)	(10.76)	(10.25)
Transportation expense ($/boe)	**(0.76)**	(1.15)	(1.00)	(1.13)	(1.33)	(1.46)	(1.21)	(1.26)
Operating netback ($/boe)	**5.96**	16.05	27.30	26.27	29.27	26.56	17.15	31.39
Financial derivatives gain (loss) ($/boe)	**2.06**	3.00	2.59	2.39	1.45	2.07	(0.34)	(4.07)
Operating netback after financial derivatives ($/boe)	**8.02**	19.05	29.89	28.66	30.72	28.63	16.81	27.32

Q2/2020 marks the eighth quarter of financial and operating results including the strategic combination with Raging River Exploration Inc. which occurred on August 22, 2018. Production reached a high of 101,115 boe/d during Q1/2019 after relatively stable crude oil prices supported an active development program in Canada and the U.S. leading into 2019. Production was relatively consistent in the quarters following Q1/2019 until we shut-in production in Canada and moderated the pace of activity in the U.S. after the sharp decline in crude oil prices in March 2020. Production of 72,508 boe/d for Q2/2020 reflects the impact of shutting in approximately 25,000 boe/d of production for April and May with approximately 80% of this back online during June.

North American benchmark commodity prices were stable throughout 2019 and were relatively strong leading into Q1/2020 with the West Texas Intermediate ("WTI") benchmark price averaging US$57.53/bbl in January. 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. The impact of this sharp decline is reflected in our realized sales price of $22.31/boe for Q2/2020. Our development programs were significantly reduced in Canada and the U.S. as a result of this decline in crude oil pricing with exploration and development spending of $9.9 million during Q2/2020 which was the lowest level of capital investment in the last 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 throughout 2019 following the strategic combination with Raging River Exploration Inc. due to increased production and higher realizations associated with the higher weighting of light oil production, as well as strong well performance. Adjusted funds flow of $17.9 million in Q2/2020 reflects the impact of lower commodity prices and shut-in production during April and May.

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 $2.1 billion at Q3/2018 to $2.0 billion at Q2/2020 which is primarily due to adjusted funds flow exceeding exploration and development expenditures by $273.0 million over the last eight quarters which reflects our efforts to preserve liquidity during periods of challenging crude oil prices. This decrease was partially offset by an increase in the CAD/USD exchange rate used to translate our U.S. dollar denominated debt from 1.2924 CAD/USD at Q3/2018 to 1.36155 CAD/USD at Q2/2020.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at June 30, 2020, 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, 2020. 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, 2019.

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 trading period.

Baytex can avoid delisting if its common shares have a closing price on the last trading day of any calendar month and a concurrent 30 trading day average closing price of at least US$1.00 per share prior to December 3, 2020. If Baytex has not regained compliance at the expiration of this date the NYSE will commence suspension and delisting procedures.

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)	**2020**	2019	**2020**	2019
Cash flow from operating activities	**$ 25,824**	$ 247,585	**$ 208,391**	$ 404,950
Change in non-cash working capital	**(8,565)**	(16,253)	**(62,438)**	42,224
Asset retirement obligations settled	**628**	4,798	**4,869**	9,726
Adjusted funds flow	**$ 17,887**	$ 236,130	**$ 150,822**	$ 456,900

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 is 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)	**2020**	2019	**2020**	2019
Cash flow used in investing activities	**$ 55,782**	$ 109,596	**$ 216,804**	$ 297,184
Change in non-cash working capital	**(44,566)**	(1,389)	**(28,239)**	(35,069)
Proceeds from dispositions	**11**	950	**51**	950
Property acquisitions	**—**	(2,597)	**—**	(2,597)
Additions to other plant and equipment	**(1,375)**	(314)	**(1,987)**	(379)
Exploration and development expenditures	**$ 9,852**	$ 106,246	**$ 186,629**	$ 260,089

Free Cash Flow

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. 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)	**2020**	2019	**2020**	2019
Adjusted funds flow	**$ 17,887**	$ 236,130	**$ 150,822**	$ 456,900
Exploration and development expenditures	**(9,852)**	(106,246)	**(186,629)**	(260,089)
Payments on lease obligations	**(1,468)**	(1,623)	**(2,984)**	(3,012)
Asset retirement obligations settled	**(628)**	(4,798)	**(4,869)**	(9,726)
Free cash flow	**$ 5,939**	$ 123,463	**$ (43,660)**	$ 184,073

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. The current portion of financial derivatives is excluded as the valuation of the underlying contracts is subject to a high degree of volatility prior to the ultimate settlement. Onerous contracts are excluded from net debt as the underlying contracts do not represent an available source of 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 liquidity or repayment obligation.

The following table summarizes our calculation of net debt.

($ thousands)	**June 30, 2020**	December 31, 2019
Credit facilities(1)	**$ 704,135**	$ 506,471
Long-term notes(1)	**1,225,395**	1,337,200
Trade and other payables	**167,193**	207,454
Cash	**—**	(5,572)
Trade and other receivables	**(101,770)**	(173,762)
Net debt	**$ 1,994,953**	$ 1,871,791

(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)	**2020**	2019	**2020**	2019
Petroleum and natural gas sales	**$ 152,689**	$ 482,000	**$ 489,303**	$ 935,424
Blending and other expense	**(5,460)**	(20,890)	**(26,817)**	(37,678)
Total sales, net of blending and other expense	**147,229**	461,110	**462,486**	897,746
Royalties	**(29,156)**	(86,617)	**(85,876)**	(167,942)
Operating expense	**(73,680)**	(100,474)	**(178,150)**	(200,766)
Transportation expense	**(5,031)**	(11,869)	**(15,373)**	(25,199)
Operating netback	**39,362**	262,150	**183,087**	503,839
Realized financial derivative gain	**13,624**	12,993	**40,474**	31,807
Operating netback after realized financial derivatives	**$ 52,986**	$ 275,143	**$ 223,561**	$ 535,646

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.

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2020**	2019	**2020**	2019
Net income (loss)	**$ (138,463)**	$ 78,826	**$ (2,636,680)**	$ 90,162
Plus:				
Financing and interest	**30,230**	32,541	**69,450**	65,283
Unrealized foreign exchange (gain) loss	**(45,516)**	(25,318)	**54,005**	(52,259)
Unrealized financial derivatives (gain) loss	**69,286**	(14,673)	**(26,709)**	38,588
Current income tax expense	**89**	495	**558**	1,090
Deferred income tax expense (recovery)	**21,002**	(1,555)	**(262,177)**	(16,040)
Depletion and depreciation	**104,540**	185,772	**285,926**	371,126
Gain on dispositions	**(11)**	(1,057)	**(148)**	(1,057)
Impairment	**—**	—	**2,716,349**	—
Non-cash items(1)	**4,206**	9,686	**6,728**	17,373
Bank EBITDA	**$ 45,363**	$ 264,717	**$ 207,302**	$ 514,266

(1) Non-cash items include share-based compensation and exploration and evaluation expense.

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, 2020.

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; that the outlook for our industry is uncertain; that we expect to remain onside our financial covenants through 2021; that the resumption of production from shut-in barrels is expected to positively impact adjusted funds flow and improve financial liquidity; our capital budget and expected average daily production for 2020; our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2020; we expect 5,000 boe/d of heavy oil to remain shut-in for the remainder of 2020; our ability to shut-in and quickly restart production; 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; that we have flexibility to increase capital expenditures in Canada in 2020; that we may pro-actively negotiate amendment to our credit facilities; that our internally generated adjusted funds flow and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures; that a significant portion of our financial obligations will be funded by adjusted funds flow.

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, 2019, 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 Statements of Financial Position
(thousands of Canadian dollars) (unaudited)

	Notes	As at June 30, 2020	As at December 31, 2019
ASSETS			
Current assets			
Cash		$ —	$ 5,572
Trade and other receivables		101,770	173,762
Financial derivatives	17	41,906	5,433
		143,676	184,767
Non-current assets			
Financial derivatives	17	1,393	—
Exploration and evaluation assets	5	198,875	320,210
Oil and gas properties	6	2,888,287	5,387,889
Other plant and equipment		8,523	7,598
Lease assets		11,853	13,619
Deferred income tax asset	14	15,213	—
		$ 3,267,820	$ 5,914,083
LIABILITIES			
Current liabilities			
Trade and other payables		$ 167,193	$ 207,454
Financial derivatives	17	19,825	8,668
Lease obligations		5,919	5,798
Asset retirement obligations	9	10,948	11,579
		203,885	233,499
Non-current liabilities			
Credit facilities	7	701,770	505,412
Long-term notes	8	1,208,066	1,328,175
Lease obligations		6,037	8,085
Asset retirement obligations	9	712,409	656,395
Deferred income tax liability		—	235,308
		2,832,167	2,966,874
SHAREHOLDERS' EQUITY			
Shareholders' capital	10	5,726,708	5,718,835
Contributed surplus		14,476	17,712
Accumulated other comprehensive income		676,711	556,224
Deficit		(5,982,242)	(3,345,562)
		435,653	2,947,209
		$ 3,267,820	$ 5,914,083

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated 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	**2020**	2019	**2020**	2019
Revenue, net of royalties					
Petroleum and natural gas sales	13	**$ 152,689**	$ 482,000	**$ 489,303**	$ 935,424
Royalties		**(29,156)**	(86,617)	**(85,876)**	(167,942)
		123,533	395,383	**403,427**	767,482
Expenses					
Operating		**73,680**	100,474	**178,150**	200,766
Transportation		**5,031**	11,869	**15,373**	25,199
Blending and other		**5,460**	20,890	**26,817**	37,678
General and administrative		**7,438**	11,506	**17,213**	25,642
Exploration and evaluation	5	**1,831**	4,685	**2,091**	6,529
Depletion and depreciation		**104,540**	185,772	**285,926**	371,126
Impairment	5, 6	**—**	—	**2,716,349**	—
Share-based compensation	11	**2,993**	5,001	**5,776**	10,844
Financing and interest	15	**30,230**	32,541	**69,450**	65,283
Financial derivatives loss (gain)	17	**55,662**	(27,666)	**(67,183)**	6,781
Foreign exchange (gain) loss	16	**(45,973)**	(24,679)	**53,919**	(52,215)
Gain on dispositions		**(11)**	(1,057)	**(148)**	(1,057)
Other expense (income)		**24**	(1,719)	**(2,007)**	(4,306)
		240,905	317,617	**3,301,726**	692,270
Net income (loss) before income taxes		**(117,372)**	77,766	**(2,898,299)**	75,212
Income tax expense (recovery)	14				
Current income tax expense		**89**	495	**558**	1,090
Deferred income tax expense (recovery)		**21,002**	(1,555)	**(262,177)**	(16,040)
		21,091	(1,060)	**(261,619)**	(14,950)
Net income (loss)		**$ (138,463)**	$ 78,826	**$ (2,636,680)**	$ 90,162
Other comprehensive income (loss)					
Foreign currency translation adjustment		**(53,452)**	(45,395)	**120,487**	(93,189)
Comprehensive income (loss)		**$ (191,915)**	$ 33,431	**$ (2,516,193)**	$ (3,027)
Net income (loss) per common share	12				
Basic		**$ (0.25)**	$ 0.14	**$ (4.71)**	$ 0.16
Diluted		**$ (0.25)**	$ 0.14	**$ (4.71)**	$ 0.16
Weighted average common shares (000's)	12				
Basic		**560,512**	556,599	**560,158**	556,022
Diluted		**560,512**	560,685	**560,158**	559,972

See accompanying notes to the condensed consolidated interim financial statements.

Baytex Energy Corp.
Condensed Consolidated 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, 2018		$ 5,701,516	$ 19,137	$ 667,874	$ (3,333,103)	**$ 3,055,424**
Vesting of share awards		10,373	(10,373)	—	—	**—**
Share-based compensation		—	10,844	—	—	**10,844**
Comprehensive income (loss)		—	—	(93,189)	90,162	**(3,027)**
Balance at June 30, 2019		$ 5,711,889	$ 19,608	$ 574,685	$ (3,242,941)	**$ 3,063,241**
Balance at December 31, 2019		$ 5,718,835	$ 17,712	$ 556,224	$ (3,345,562)	**$ 2,947,209**
Vesting of share awards	10	7,873	(7,873)	—	—	**—**
Share-based compensation	11	—	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**

See accompanying notes to the condensed consolidated interim financial statements.

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

	Notes	Three Months Ended June 30 2020	Three Months Ended June 30 2019	Six Months Ended June 30 2020	Six Months Ended June 30 2019
CASH PROVIDED BY (USED IN):					
Operating activities					
Net income (loss) for the period		**$ (138,463)**	$ 78,826	**$ (2,636,680)**	$ 90,162
Adjustments for:					
Share-based compensation	11	**2,375**	5,001	**4,637**	10,844
Unrealized foreign exchange (gain) loss	16	**(45,516)**	(25,318)	**54,005**	(52,259)
Exploration and evaluation	5	**1,831**	4,685	**2,091**	6,529
Depletion and depreciation		**104,540**	185,772	**285,926**	371,126
Impairment	5, 6	**—**	—	**2,716,349**	—
Non-cash financing, accretion, and early redemption expense	15	**2,843**	4,449	**13,528**	9,007
Unrealized financial derivatives loss (gain)	17	**69,286**	(14,673)	**(26,709)**	38,588
Gain on dispositions		**(11)**	(1,057)	**(148)**	(1,057)
Deferred income tax expense (recovery)	14	**21,002**	(1,555)	**(262,177)**	(16,040)
Asset retirement obligations settled	9	**(628)**	(4,798)	**(4,869)**	(9,726)
Change in non-cash working capital		**8,565**	16,253	**62,438**	(42,224)
		25,824	247,585	**208,391**	404,950
Financing activities					
Increase (decrease) in credit facilities		**31,426**	(136,366)	**187,347**	(104,754)
Payments on lease obligations		**(1,468)**	(1,623)	**(2,984)**	(3,012)
Net proceeds from issuance of long-term notes	8	**—**	—	**652,150**	—
Redemption of long-term notes	8	**—**	—	**(833,672)**	—
		29,958	(137,989)	**2,841**	(107,766)
Investing activities					
Additions to exploration and evaluation assets	5	**(72)**	(269)	**(3,860)**	(1,394)
Additions to oil and gas properties	6	**(9,780)**	(105,977)	**(182,769)**	(258,695)
Additions to other plant and equipment		**(1,375)**	(314)	**(1,987)**	(379)
Property acquisitions		**—**	(2,597)	**—**	(2,597)
Proceeds from dispositions		**11**	950	**51**	950
Change in non-cash working capital		**(44,566)**	(1,389)	**(28,239)**	(35,069)
		(55,782)	(109,596)	**(216,804)**	(297,184)
Change in cash		**—**	—	**(5,572)**	—
Cash, beginning of period		**—**	—	**5,572**	—
Cash, end of period		**$ —**	$ —	**$ —**	$ —
Supplementary information					
Interest paid		**$ 29,183**	$ 34,143	**$ 51,780**	$ 56,179
Income taxes paid		**$ —**	$ 1,082	**$ —**	$ 1,082

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 the United States. The Company’s common shares are traded on the Toronto Stock Exchange and the New York 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 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, 2019.

The consolidated financial statements were approved by the Board of Directors of Baytex on July 29, 2020.

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, 2019 are available through its filings on SEDAR at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies, critical accounting judgments and significant estimates used in preparation of the 2019 annual financial statements have been applied in the preparation of these consolidated financial statements, except for the adoption of amendments to IFRS 3 *Business Combinations* as described below.

Current environment and estimation uncertainty

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

In March 2020, the World Health Organization declared a global pandemic related to the novel coronavirus disease 2019 ("COVID-19"). The emergence of COVID-19 and the steps taken by governments to control the spread of the virus has resulted in significant instability in the global economy. The North American oil and gas industry has been particularly impacted as restrictions attempting to limit the spread of COVID-19 have resulted in a sharp decline in demand for crude oil combined with additional supply from the OPEC+ price war have resulted in unprecedented volatility in global crude oil prices. Global crude oil prices began to recover in Q2/2020 as members of OPEC+ agreed to production curtailments and governments began to ease restrictions that allowed economies to begin reopening. While these factors have resulted in recent improvements in crude oil prices the outlook for our industry remains uncertain due to the ongoing spread of COVID-19.

These factors have impacted our results for the six months ended June 30, 2020. At March 31, 2020, we recorded a total impairment of $2.7 billion which included amounts related to our exploration and evaluation assets (note 5) and oil and gas properties (note 6). There is potential for further impairments or reversal of impairments over the balance of 2020 due to the current volatility in forecasted prices for the commodities we produce. In the current environment, assumptions and estimates regarding future commodity prices, the amount of economically recoverable reserves, exchange rates, and interest rates are subject to greater variability than normal. Actual results may differ from these estimates as the effect of future events cannot be determined with certainty.

We have taken action to protect our financial liquidity in response to the recent volatility in commodity prices and instability in the global economy. We have reduced our planned capital expenditures and have reduced production of oil and natural gas when commodity prices do not support economic production. Production could be further reduced or restarted in response to further changes in the commodity price environment. We currently have $363.0 million of availability on our credit facilities and are currently forecasting to remain in compliance with the financial covenants applicable to our credit facilities through at least December 31, 2021 based on current forward commodity prices.

Business Combinations

Baytex adopted amendments to IFRS 3 *Business Combinations* effective January 1, 2020, which will be applied prospectively to acquisitions that occur on or after January 1, 2020. These amendments did not result in changes to the Company's accounting policies for applying the acquisition method but could result in future acquisitions being accounted for as an asset acquisition as opposed to a business combination.

4. 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	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 73,325**	$ 294,698	**$ 79,364**	$ 187,302	**$ —**	$ —	**$ 152,689**	$ 482,000
Royalties	**(6,157)**	(30,936)	**(22,999)**	(55,681)	**—**	—	**(29,156)**	(86,617)
	67,168	263,762	**56,365**	131,621	**—**	—	**123,533**	395,383
Expenses								
Operating	**49,162**	73,877	**24,518**	26,597	**—**	—	**73,680**	100,474
Transportation	**5,031**	11,869	**—**	—	**—**	—	**5,031**	11,869
Blending and other	**5,460**	20,890	**—**	—	**—**	—	**5,460**	20,890
General and administrative	**—**	—	**—**	—	**7,438**	11,506	**7,438**	11,506
Exploration and evaluation	**1,831**	4,685	**—**	—	**—**	—	**1,831**	4,685
Depletion and depreciation	**57,650**	116,325	**44,972**	68,907	**1,918**	540	**104,540**	185,772
Share-based compensation	**—**	—	**—**	—	**2,993**	5,001	**2,993**	5,001
Financing and interest	**—**	—	**—**	—	**30,230**	32,541	**30,230**	32,541
Financial derivatives loss (gain)	**—**	—	**—**	—	**55,662**	(27,666)	**55,662**	(27,666)
Foreign exchange gain	**—**	—	**—**	—	**(45,973)**	(24,679)	**(45,973)**	(24,679)
Gain on dispositions	**(11)**	(1,057)	**—**	—	**—**	—	**(11)**	(1,057)
Other expense (income)	**—**	—	**—**	—	**24**	(1,719)	**24**	(1,719)
	119,123	226,589	**69,490**	95,504	**52,292**	(4,476)	**240,905**	317,617
Net income (loss) before income taxes	**(51,955)**	37,173	**(13,125)**	36,117	**(52,292)**	4,476	**(117,372)**	77,766
Income tax expense (recovery)								
Current income tax expense	**—**	—	**89**	495	**—**	—	**89**	495
Deferred income tax expense (recovery)	**6,421**	(140)	**21,002**	2,014	**(6,421)**	(3,429)	**21,002**	(1,555)
	6,421	(140)	**21,091**	2,509	**(6,421)**	(3,429)	**21,091**	(1,060)
Net income (loss)	**$ (58,376)**	$ 37,313	**$ (34,216)**	$ 33,608	**$ (45,871)**	$ 7,905	**$ (138,463)**	$ 78,826
Total oil and natural gas capital expenditures[(1)]	**$ 2,918**	$ 69,906	**$ 6,923**	$ 37,987	**$ —**	$ —	**$ 9,841**	$ 107,893

	Canada		U.S.		Corporate		Consolidated	
Six Months Ended June 30	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 268,169**	$ 558,737	**$ 221,134**	$ 376,687	**$ —**	$ —	**$ 489,303**	$ 935,424
Royalties	**(21,675)**	(56,120)	**(64,201)**	(111,822)	**—**	—	**(85,876)**	(167,942)
	246,494	502,617	**156,933**	264,865	**—**	—	**403,427**	767,482
Expenses								
Operating	**128,084**	147,979	**50,066**	52,787	**—**	—	**178,150**	200,766
Transportation	**15,373**	25,199	**—**	—	**—**	—	**15,373**	25,199
Blending and other	**26,817**	37,678	**—**	—	**—**	—	**26,817**	37,678
General and administrative	**—**	—	**—**	—	**17,213**	25,642	**17,213**	25,642
Exploration and evaluation	**2,091**	6,529	**—**	—	**—**	—	**2,091**	6,529
Depletion and depreciation	**180,398**	231,345	**101,642**	138,731	**3,886**	1,050	**285,926**	371,126
Impairment	**1,855,000**	—	**861,349**	—	**—**	—	**2,716,349**	—
Share-based compensation	**—**	—	**—**	—	**5,776**	10,844	**5,776**	10,844
Financing and interest	**—**	—	**—**	—	**69,450**	65,283	**69,450**	65,283
Financial derivatives (gain) loss	**—**	—	**—**	—	**(67,183)**	6,781	**(67,183)**	6,781
Foreign exchange loss (gain)	**—**	—	**—**	—	**53,919**	(52,215)	**53,919**	(52,215)
Gain on dispositions	**(148)**	(1,057)	**—**	—	**—**	—	**(148)**	(1,057)
Other income	**—**	—	**—**	—	**(2,007)**	(4,306)	**(2,007)**	(4,306)
	2,207,615	447,673	**1,013,057**	191,518	**81,054**	53,079	**3,301,726**	692,270
Net income (loss) before income taxes	**(1,961,121)**	54,944	**(856,124)**	73,347	**(81,054)**	(53,079)	**(2,898,299)**	75,212
Income tax expense (recovery)								
Current income tax expense	**469**	—	**89**	1,090	**—**	—	**558**	1,090
Deferred income tax (recovery) expense	**(85,276)**	4,108	**(164,994)**	4,708	**(11,907)**	(24,856)	**(262,177)**	(16,040)
	(84,807)	4,108	**(164,905)**	5,798	**(11,907)**	(24,856)	**(261,619)**	(14,950)
Net income (loss)	**$(1,876,314)**	$ 50,836	**$ (691,219)**	$ 67,549	**$ (69,147)**	$ (28,223)	**$(2,636,680)**	$ 90,162
Total oil and natural gas capital expenditures[1]	**$ 125,989**	$ 174,776	**$ 60,589**	$ 86,960	**$ —**	$ —	**$ 186,578**	$ 261,736

(1) Includes acquisitions and property swaps, net of proceeds from divestitures.

	June 30, 2020	December 31, 2019
Canadian assets	**$ 1,571,844**	$ 3,484,123
U.S. assets	**1,632,301**	2,403,310
Corporate assets	**63,675**	26,650
Total consolidated assets	**$ 3,267,820**	$ 5,914,083

5. EXPLORATION AND EVALUATION ASSETS

	June 30, 2020	December 31, 2019
Balance, beginning of period	**$ 320,210**	$ 358,935
Capital expenditures	**3,860**	2,948
Property acquisitions	**—**	1,523
Divestitures	**—**	(443)
Property swaps	**479**	417
Impairment	**(127,861)**	(7,822)
Exploration and evaluation expense	**(2,091)**	(11,764)
Transfer to oil and gas properties (note 6)	**(3,689)**	(16,204)
Foreign currency translation	**7,967**	(7,380)
Balance, end of period	**$ 198,875**	$ 320,210

At June 30, 2020, 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 of $127.9 million was recorded as 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 booked for each CGU at March 31, 2020.

	Impairment
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, 2019, the Company identified indicators of impairment for the exploration and evaluation assets within the Peace River CGU. The estimated recoverable amount was below the carrying value of the exploration and evaluation assets in the Peace River CGU and an impairment of $7.8 million was recorded as at December 31, 2019. There were no indicators of impairment for exploration and evaluation assets in the remaining CGUs at December 31, 2019.

6. OIL AND GAS PROPERTIES

		Cost		Accumulated depletion		Net book value
Balance, December 31, 2018	**$**	**10,744,533**	**$**	**(4,926,644)**	**$**	**5,817,889**
Capital expenditures		549,343		—		549,343
Property acquisitions		2,636		—		2,636
Transfers from exploration and evaluation assets (note 5)		16,204		—		16,204
Change in asset retirement obligations (note 9)		23,894		—		23,894
Divestitures		(2,069)		1,690		(379)
Property swaps		1,773		—		1,773
Impairment		—		(180,000)		(180,000)
Foreign currency translation		(208,017)		89,813		(118,204)
Depletion		—		(725,267)		(725,267)
Balance, December 31, 2019	**$**	**11,128,297**	**$**	**(5,740,408)**	**$**	**5,387,889**
Capital expenditures		182,769		—		182,769
Transfers from exploration and evaluation assets (note 5)		3,689		—		3,689
Change in asset retirement obligations (note 9)		54,155		—		54,155
Property swaps		(1,190)		178		(1,012)
Impairment		—		(2,588,488)		(2,588,488)
Foreign currency translation		194,643		(63,318)		131,325
Depletion		—		(282,040)		(282,040)
Balance, June 30, 2020	**$**	**11,562,363**	**$**	**(8,674,076)**	**$**	**2,888,287**

At June 30, 2020, there were no indicators of impairment or impairment reversal for oil and gas properties in any of the Company's CGUs.

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.

	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

This data is combined with assumptions relating to long-term prices, inflation rates and exchange rates together with estimates of transportation costs and pricing of competing fuels to forecast long-term energy prices, consistent with external sources of information. The prices and costs subsequent to 2029 have been adjusted for inflation at an annual rate of 2.0%.

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		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, 2019, the Company identified indicators of impairment for its Peace River CGU due to a sustained decline in Canadian heavy oil prices and a reduction in planned exploration and development expenditures related to thermal properties in the Peace River CGU. The recoverable amount of the Peace River CGU was based on its value-in-use ("VIU") which was estimated using a discounted cash flow model using proved plus probable cash flows from an independent reserve report prepared as at December 31,2019 and an after-tax discount rate of 11%. The recoverable amount was not sufficient to support the carrying amount of the CGU which resulted in an impairment of $180.0 million recorded as at December 31, 2019. There were no indicators of impairment or impairment reversal for the remaining CGUs as at December 31, 2019.

7. CREDIT FACILITIES

		June 30, 2020		December 31, 2019
Credit facilities - U.S. dollar denominated[(1)]	**$**	**153,730**	$	206,144
Credit facilities - Canadian dollar denominated		**550,405**		300,327
Credit facilities - principal		**704,135**		506,471
Unamortized debt issuance costs		**(2,365)**		(1,059)
Credit facilities	**$**	**701,770**	$	505,412

(1) U.S. dollar denominated credit facilities balance was US$112.9 million as at June 30, 2020 (December 31, 2019 - US$159.0 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"). On March 3, 2020, Baytex amended its Credit Facilities to extend maturity from April 2, 2021 to April 2, 2024. These facilities 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, plus applicable margins. In the event that Baytex breaches any of the covenants under the Credit Facilities, Baytex may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to shareholders.

At June 30, 2020, Baytex had $15.8 million of outstanding letters of credit (December 31, 2019 - $15.2 million) under the Credit Facilities.

At June 30, 2020, Baytex was in compliance with all of the covenants contained in the Credit Facilities and is forecasting compliance with these covenants through at least December 31, 2021 based on current forward commodity prices. A decrease or a sustained period of low commodity prices may result in non-compliance with our financial covenants and reduced liquidity on our existing credit facilities. Non-compliance with the financial covenants in our credit facilities could result in our debt becoming due and payable on demand. If we anticipate non-compliance we will pro-actively approach our lending syndicate to amend the credit facilities to maintain their availability. There is no certainty that we will be successful in negotiating such amendments. The following table summarizes the financial covenants applicable to the Credit Facilities and Baytex's compliance therewith as at June 30, 2020.

Covenant Description	**Position as at June 30, 2020**	**Covenant**
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**1.0:1.0**	**3.5:1.0**
Interest Coverage(3) (Minimum Ratio)	**6.6:1.0**	**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, 2020, the Company's Senior Secured Debt totaled $719.9 million which includes $704.1 million of principal amounts outstanding and $15.8 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, 2020 was $704.4 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, 2020 was $106.5 million.

8. LONG-TERM NOTES

		June 30, 2020		December 31, 2019
5.125% notes (US$400,000 – principal) due June 1, 2021	**$**	**—**	$	518,600
6.625% notes ($300,000 – principal) due July 19, 2022		**—**		300,000
5.625% notes (US$400,000 – principal) due June 1, 2024		**544,620**		518,600
8.75% notes (US$500,000 – principal) due April 1, 2027		**680,775**		—
Total long-term notes - principal(1)		**1,225,395**		1,337,200
Unamortized debt issuance costs		**(17,329)**		(9,025)
Total long-term notes - net of unamortized debt issuance costs	**$**	**1,208,066**	$	1,328,175

(1) The decrease in the principal amount of long-term notes outstanding from December 31, 2019 to June 30, 2020 is the result of principal repayments of $830.4 million, the issuance of $664.7 million aggregate principal amount and changes in the reported amount of U.S. dollar denominated debt of $53.8 million.

On February 5, 2020, Baytex 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 Baytex's 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.

On February 20, 2020, Baytex used a portion of the net proceeds from the issuance of the 8.75% Senior Notes to complete the early redemption of the US$400 million principal amount of the 5.125% senior unsecured notes due June 1, 2021 at par plus accrued interest. The principal payment was $530.4 million.

On March 5, 2020, Baytex completed the early redemption of the $300 million principal amount of the 6.625% senior unsecured notes due July 19, 2022 at 101.104% of the principal amount, plus accrued interest. The principal payment was $300.0 million plus early redemption expense of $3.3 million.

The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts the Company's ability to raise additional debt beyond the existing Credit Facilities and long-term notes unless the Company maintains a minimum coverage ratio (computed as the ratio of Bank EBITDA (as defined in note 7) to financing and interest expense on a trailing twelve month basis) of 2.00:1.00. At June 30, 2020, the fixed charge coverage ratio was 6.2:1.0.

9. ASSET RETIREMENT OBLIGATIONS

		June 30, 2020		December 31, 2019
Balance, beginning of period	**$**	**667,974**	$	646,898
Liabilities incurred		**10,362**		21,748
Liabilities settled		**(4,869)**		(15,417)
Liabilities acquired from property acquisitions		**—**		1,648
Liabilities divested		**(116)**		(1,331)
Property swaps		**(514)**		792
Accretion (note 15)		**5,109**		13,713
Change in estimate		**(3,978)**		19,632
Changes in discount rates and inflation rates(1)		**47,771**		(17,486)
Foreign currency translation		**1,618**		(2,223)
Balance, end of period	**$**	**723,357**	$	667,974
Less current portion of asset retirement obligations		**10,948**		11,579
Non-current portion of asset retirement obligations	**$**	**712,409**	$	656,395

(1) The discount and inflation rates at June 30, 2020 were both 1.0%, compared to 1.8% and 1.4%, respectively, at December 31, 2019.

10. 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, 2020, 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, 2018	**554,060**	**$**	**5,701,516**
Vesting of share awards	4,245		17,319
Balance, December 31, 2019	**558,305**	**$**	**5,718,835**
Vesting of share awards	2,240		7,873
Balance, June 30, 2020	**560,545**	**$**	**5,726,708**

11. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to the share awards of $3.0 million and $5.8 million for the three and six months ended June 30, 2020 ($5.0 million and $10.8 million for the three and six months ended June 30, 2019) which includes $0.6 million and $1.1 million of cash compensation expense related to the incentive award plan and the associated equity total return swaps.

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 $1.48 per restricted and performance award for the six months ended June 30, 2020 ($2.65 per restricted and performance award for the six months ended June 30, 2019).

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, 2018	**3,243**	**3,273**	**6,516**
Granted	3,184	3,245	6,429
Vested and converted to common shares	(2,081)	(2,164)	(4,245)
Forfeited	(545)	(1,219)	(1,764)
Balance, December 31, 2019	**3,801**	**3,135**	**6,936**
Granted	2,239	3,253	5,492
Vested and converted to common shares	(1,378)	(862)	(2,240)
Forfeited	(137)	(185)	(322)
Balance, June 30, 2020	**4,525**	**5,341**	**9,866**

(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.

The Company uses equity total return swaps ("Equity TRS") on the equivalent number of Baytex common shares in order to fix the aggregate cost of the Incentive Award plan at the fair value determined on the grant date. The cumulative expense is recognized at fair value each period with realized gains or losses included in share-based compensation expense and unrealized gains or losses included in unrealized financial derivatives gain or loss. The carrying value of the financial derivatives includes the fair value of the Equity TRS which was a liability of $1.7 million on June 30, 2020.

During the three and six months ended June 30, 2020, Baytex granted 2.9 million awards under the Incentive Award plan at a fair value of $1.50 per award.

Share Options

Baytex assumed share option plans pursuant to a business combination in 2018. No new grants will be made under the option plans.

The Company accounts for share options using the fair value method. Under this method, compensation is expensed over the vesting period for the share options, with a corresponding increase to contributed surplus.

Share options granted under the option plans had a maximum term of 3.5 years to expiry. One third of the options granted vest on each of the first, second, and third anniversaries of the date of grant. The following tables summarize the information about the share options.

	Number of options (000s)		Weighted average exercise price
Balance, December 31, 2018	**4,865**	**$**	**6.70**
Forfeited/Expired	(2,390)		6.56
Balance, December 31, 2019	**2,475**	**$**	**6.83**
Forfeited/Expired	(1,385)		7.25
Balance, June 30, 2020	**1,090**	**$**	**6.30**

	Options Outstanding				**Options Exercisable**		
Exercise price	Number outstanding at June 30, 2020 (000s)	Weighted average remaining life (years)		Weighted average exercise price	Number exercisable at June 30, 2020 (000s)		Weighted average exercise price
$5.00 - $7.00	1,090	0.40	$	6.30	998	$	6.39
Total	**1,090**	**0.40**	**$**	**6.30**	**998**	**$**	**6.39**

12. NET INCOME (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					
	2020			2019		
	Net loss	**Weighted average common shares (000s)**	**Net loss per share**	Net income	Weighted average common shares (000s)	Net income per share
Net income (loss) - basic	**$ (138,463)**	**560,512**	**$ (0.25)**	$ 78,826	556,599	$ 0.14
Dilutive effect of share awards	**—**	**—**	**—**	—	4,086	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net income (loss) - diluted	**$ (138,463)**	**560,512**	**$ (0.25)**	$ 78,826	560,685	$ 0.14

	Six Months Ended June 30					
	2020			2019		
	Net loss	**Weighted average common shares (000s)**	**Net loss per share**	Net income	Weighted average common shares (000s)	Net income per share
Net income (loss) - basic	**$ (2,636,680)**	**560,158**	**$ (4.71)**	$ 90,162	556,022	$ 0.16
Dilutive effect of share awards	**—**	**—**	**—**	—	3,950	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net income (loss) - diluted	**$ (2,636,680)**	**560,158**	**$ (4.71)**	$ 90,162	559,972	$ 0.16

For the three and six months ended June 30, 2020, all share awards and share options were excluded from the calculation as their effect was anti-dilutive as the Company recorded a net loss. For the three and six months ended June 30, 2019, no share awards were considered to be anti-dilutive and 4.0 million share options were excluded from the calculation of diluted earnings per share as they were determined to be anti-dilutive.

13. 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					
	2020			2019		
	Canada	U.S.	Total	Canada	U.S.	Total
Light oil and condensate	$ 42,231	$ 61,043	$ 103,274	$ 141,827	$ 153,504	$ 295,331
Heavy oil	24,003	—	24,003	146,038	—	146,038
NGL	847	8,035	8,882	1,757	15,808	17,565
Natural gas sales	6,244	10,286	16,530	5,076	17,990	23,066
Total petroleum and natural gas sales	$ 73,325	$ 79,364	$ 152,689	$ 294,698	$ 187,302	$ 482,000

	Six Months Ended June 30					
	2020			2019		
	Canada	U.S.	Total	Canada	U.S.	Total
Light oil and condensate	$ 151,314	$ 182,198	$ 333,512	$ 274,195	$ 302,419	$ 576,614
Heavy oil	99,846	—	99,846	263,724	—	263,724
NGL	2,196	16,877	19,073	5,198	36,610	41,808
Natural gas sales	14,813	22,059	36,872	15,620	37,658	53,278
Total petroleum and natural gas sales	$ 268,169	$ 221,134	$ 489,303	$ 558,737	$ 376,687	$ 935,424

Included in accounts receivable at June 30, 2020 is $79.8 million of accrued production revenue related to delivered volumes (December 31, 2019 - $138.0 million).

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Six Months Ended June 30	
	2020	2019
Net loss before income taxes	$ (2,898,299)	$ 75,212
Expected income taxes at the statutory rate of 25.89% (2019 – 26.72%)	(750,370)	20,097
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	1,200	2,898
Non-taxable portion of foreign exchange loss (gain)	6,968	(7,044)
Effect of change in income tax rates	22,269	(10,573)
Effect of rate adjustments for foreign jurisdictions	36,097	(14,427)
Effect of change in deferred tax benefit not recognized	400,423	(6,532)
Effect of U.S. tax change	20,160	—
Adjustments and assessments	1,634	631
Income tax recovery	$ (261,619)	$ (14,950)

On May 28, 2019 the Alberta government tabled legislation to decrease the corporate income tax rate from 12% to 8% over a multi-year period beginning July 1, 2019 and ending January 1, 2022. On June 29, 2020 the Alberta government announced that the corporate tax rate reduction to 8% previously scheduled for January 1, 2022 would be accelerated to July 1, 2020. Legislation enacting this accelerated timeline is still pending and accordingly the effect is not reflected in the deferred tax recovery recorded for the six months ended June 30, 2020.

At June 30, 2020, a deferred tax asset of $15.2 million has been recognized while $428 million remains unrecognized due to uncertainty surrounding future commodity prices (December 31, 2019 - $28 million).

As disclosed in the 2019 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.

On April 7, 2020, the U.S. Department of the Treasury and the IRS published final regulations addressing "anti-hybrid" rules under section 267A of the U.S. tax code and thus became substantially enacted. Pursuant to these regulations, the Company is no longer entitled to certain tax benefits previously recognized during 2019. Accordingly, a charge against deferred income taxes in the amount of $20.2 million was recorded in the three months ended June 30, 2020.

15. FINANCING AND INTEREST

	Three Months Ended June 30		Six Months Ended June 30	
	2020	2019	**2020**	2019
Interest on credit facilities	**$ 4,248**	$ 5,109	**$ 8,383**	$ 10,521
Interest on long-term notes	**23,015**	22,825	**47,288**	45,427
Interest on lease obligations	**124**	158	**251**	328
Non-cash financing	**665**	1,051	**5,107**	2,146
Accretion on asset retirement obligations (note 9)	**2,178**	3,398	**5,109**	6,861
Early redemption expense (note 8)	**—**	—	**3,312**	—
Financing and interest	**$ 30,230**	$ 32,541	**$ 69,450**	$ 65,283

16. FOREIGN EXCHANGE

	Three Months Ended June 30		Six Months Ended June 30	
	2020	2019	**2020**	2019
Unrealized foreign exchange (gain) loss	**$ (45,516)**	$ (25,318)	**$ 54,005**	$ (52,259)
Realized foreign exchange (gain) loss	**(457)**	639	**(86)**	44
Foreign exchange (gain) loss	**$ (45,973)**	$ (24,679)	**$ 53,919**	$ (52,215)

17. 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, 2020		December 31, 2019		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial derivatives	**$ 43,299**	**$ 43,299**	$ 5,433	$ 5,433	Level 2
Total	**$ 43,299**	**$ 43,299**	$ 5,433	$ 5,433	
Financial assets at amortized cost					
Cash	**$ —**	**$ —**	$ 5,572	$ 5,572	—
Trade and other receivables	**101,770**	**101,770**	173,762	173,762	—
Total	**$ 101,770**	**$ 101,770**	$ 179,334	$ 179,334	
Financial Liabilities					
FVTPL					
Financial derivatives	**$ (19,825)**	**$ (19,825)**	$ (8,668)	$ (8,668)	Level 2
Total	**$ (19,825)**	**$ (19,825)**	$ (8,668)	$ (8,668)	
Financial liabilities at amortized cost					
Trade and other payables	**$ (167,193)**	**$ (167,193)**	$ (207,454)	$ (207,454)	—
Credit facilities	**(701,770)**	**(704,135)**	(505,412)	(506,471)	—
Long-term notes	**(1,208,066)**	**(670,458)**	(1,328,175)	(1,290,817)	Level 1
Total	**$ (2,077,029)**	**$ (1,541,786)**	$ (2,041,041)	$ (2,004,742)	

There were no transfers between Level 1 and Level 2 during the six months ended June 30, 2020 and 2019.

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, 2020	December 31, 2019	**June 30, 2020**	December 31, 2019
U.S. dollar denominated	**US$31,708**	US$8,733	**US$927,633**	US$841,961

Interest Rate Risk

Interest Rate Swaps

As of June 30, 2020, Baytex had an interest rate swap acquired in a business combination in 2018 outstanding with a notional value of $100 million maturing in October 2020, with a fixed contract price of 2.02% referencing the Canadian Dollar Offered Rate. At June 30, 2020, the fair value of the interest rate swap was a liability of $0.5 million (December 31, 2019 - nil).

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of July 29, 2020:

	Remaining Period	Volume	Price/Unit(1)	Index
Oil				
WCS Stream(8)	July 2020	8,000 bbl/d	$27.15/bbl	Blended
WCS Stream(8)	August 2020	5,000 bbl/d	$32.05/bbl	Blended
Basis Swap	July 2020 to Dec 2020	6,500 bbl/d	WTI less US$16.27/bbl	WCS
Basis Swap	Jan 2021 to Dec 2021	4,000 bbl/d	WTI less US$14.26/bbl	WCS
MSW Stream(7)	July 2020	11,695 bbl/d	$27.17/bbl	Blended
MSW Stream(7)	August 2020	5,000 bbl/d	$42.28/bbl	Blended
Basis Swap	July 2020 to Dec 2020	5,000 bbl/d	WTI less US$6.15/bbl	MSW
Basis Swap(9)	Jan 2021 to Dec 2021	2,000 bbl/d	WTI less US$5.95/bbl	MSW
Fixed - Sell	July 2020	4,000 bbl/d	US$24.73/bbl	WTI
Fixed - Sell	July 2020	9,500 bbl/d	$36.32/bbl	WTI-CAD
Fixed - Sell	August 2020	5,000 bbl/d	US$36.30/bbl	WTI
Fixed - Sell	August 2020	5,000 bbl/d	$48.55/bbl	WTI-CAD
Fixed - Sell	July 2020 to Dec 2020	6,000 bbl/d	US$43.50/bbl	WTI
Fixed - Sell	October 2020 to Dec 2020	2,000 bbl/d	US$40.61/bbl	WTI
3-way option(2)	July 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$56.00/US$61.35	WTI
3-way option(2)	July 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$57.00/US$60.00	WTI
3-way option(2)	July 2020 to Dec 2020	4,500 bbl/d	US$50.00/US$57.00/US$62.00	WTI
3-way option(2)	July 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$58.00/US$62.00	WTI
3-way option(2)	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.50	WTI
3-way option(2)	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.83	WTI
3-way option(2)	July 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI
3-way option(2)	July 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI
3-way option(2)	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI
3-way option(2)	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI
3-way option(2)	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI
3-way option(2)	July 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI
3-way option(2)	July 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	WTI
3-way option(2)(9)	Jan 2021 to Dec 2021	5,000 bbl/d	US$35.00/US$45.00/US$55.00	WTI
Swaption(3)	Jan 2021 to Dec 2021	3,000 bbl/d	US$64.50/bbl	Brent
Swaption(4)	Jan 2021 to Dec 2021	3,000 bbl/d	US$70.00/bbl	Brent
Swaption(4)	Jan 2021 to Dec 2021	3,000 bbl/d	US$60.75/bbl	WTI
Swaption(6)(9)	Jan 2022 to Dec 2022	5,000 bbl/d	US$53.00/bbl	WTI
Natural Gas				
Fixed - Sell	July 2020 to Dec 2020	10,500 GJ/d	$2.01/GJ	AECO 7A
Fixed - Sell	Jan 2021 to Dec 2021	13,000 GJ/d	$2.29/GJ	AECO 7A
Fixed - Sell	July 2020 to Dec 2020	2,500 GJ/d	$2.29/GJ	AECO 5A
Fixed - Sell (9)	Jan 2021 to Dec 2021	2,500 GJ/d	$2.40/GJ	AECO 5A
Fixed - Sell	Oct 2020 to Dec 2020	5,500 mmbtu/d	US$2.64/mmbtu	NYMEX
Fixed - Sell	Jan 2021 to Dec 2021	12,000 mmbtu/d	US$2.70/mmbtu	NYMEX
3-way option(2)	July 2020 to Dec 2020	5,000 mmbtu/d	US$2.25/US$2.60/US$2.85	NYMEX
Swaption(5)	Jan 2021 to Dec 2021	5,000 mmbtu/d	US$2.90/mmbtu	NYMEX

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

(2) Producer 3-way option consists of a sold put, bought put, and a sold call. To illustrate, in a US$50.00/US$58.00/US$62.00 contract, Baytex receives WTI plus US$8.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$58.00/bbl when WTI is between US$50.00/bbl and US$58.00/bbl; Baytex receives the market price when WTI is between US$58.00/bbl and US$62.00/bbl; and Baytex receives US $62.00/bbl when WTI is above US$62.00/bbl.
(3) For these contracts, the counterparty has the right, if exercised on September 30, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.
(4) For these contracts, the counterparty has the right, if exercised on December 31, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.
(5) For these contracts, the counterparty has the right, if exercised on December 23, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.
(6) 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.
(7) For these contracts, the contract price per unit is the sum of the average WTI price for the period and the average of the Edmonton SW blend differential (the average of TMX SW 1a index as determined by NGX and the NE Monthly Index for physical SW as determined by Net Energy), converted to CAD at the noon day average rate.
(8) For these contracts, the contract price per unit is the sum of the average WTI price for the period and the average of the Western Canadian Select blend differential (the average of the Natural Gas Exchange Inc's WCS Index Differential and the Net Energy Inc.'s WCS Index Differential), converted to CAD at the noon day average rate.
(9) Contracts entered subsequent to June 30, 2020.

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	
	2020	2019	**2020**	2019
Realized financial derivatives gain	**$ (13,624)**	$ (12,993)	**$ (40,474)**	$ (31,807)
Unrealized financial derivatives loss (gain)	**69,286**	(14,673)	**(26,709)**	38,588
Financial derivatives loss (gain)	**$ 55,662**	$ (27,666)	**$ (67,183)**	$ 6,781

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements, opportunities to issue additional common shares as well as reducing capital expenditures.

As at June 30, 2020, Baytex had availability of $363.0 million on its Credit Facilities (December 31, 2019 - $523.8 million).

The timing of cash outflows relating to financial liabilities as at June 30, 2020 is outlined in the table below:

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 167,193**	$ 167,193	$ —	$ —	$ —
Credit facilities(1)(2)	**704,135**	—	—	704,135	—
Long-term notes(2)	**1,225,395**	—	—	544,620	680,775
Interest on long-term notes(3)	**522,472**	90,203	180,405	147,253	104,611
Lease obligations	**12,591**	6,268	5,834	489	—
	$ 2,631,786	**$ 263,664**	**$ 186,239**	**$ 1,396,497**	**$ 785,386**

(1) At December 31, 2019, the credit facilities were set to mature on April 2, 2021. On March 3, 2020, Baytex amended the credit facilities to extend maturity to April 2, 2024 which will automatically be extended to June 4, 2024 providing the Company 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. On February 5, 2020, Baytex issued US$500 million principal amount of 8.75% senior unsecured notes due 2027 and issued a redemption notice for the $300 million principal amount of 6.625% senior unsecured notes due 2022 (note 8). The Company completed the redemption of these notes on March 5, 2020. On February 20, 2020 Baytex completed the redemption of the US$400 million principal amount of senior unsecured notes due 2021 (note 8).
(3) Excludes interest on credit facilities as interest payments on credit facilities fluctuate based on amounts outstanding and interest rates.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. As at June 30, 2020, the Company is exposed to credit risk with respect to its trade and other receivables and financial derivatives. Baytex manages these risks through the selection and monitoring of credit-worthy counterparties.

Most of the Company's trade and other receivables relate to petroleum and natural gas sales. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts after reviewing the creditworthiness of the entity. Letters of credit or parental guarantees may be obtained prior to the commencement of business with certain counterparties. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers all financial assets that are not impaired or past due to be of good credit quality.

The majority of the Company's credit exposure on trade and other receivables at June 30, 2020 relates to accrued revenues and our financial hedging contracts. Accounts receivable from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. Included in trade and other receivables at June 30, 2020 is $79.8 million (December 31, 2019 - $138.0 million) of accrued petroleum and natural gas sales related to delivered volumes.

Should the Company determine that the ultimate collection of a receivable is in doubt, the carrying amount of trade and other receivables is reduced by adjusting the allowance for doubtful accounts and a charge to net income or loss. If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. As at June 30, 2020, allowance for doubtful accounts was $1.6 million (December 31, 2019 - $1.6 million).

In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. As at June 30, 2020, trade and other receivables that Baytex has deemed past due (more than 90 days) but not impaired was $1.8 million (December 31, 2019 - $2.7 million). Baytex has estimated the lifetime expected credit loss as at and for the quarter ended June 30, 2020 to be nominal.

The Company's trade and other receivables, net of the allowance for doubtful accounts, were aged as follows as at June 30, 2020.

	June 30, 2020	December 31, 2019
Current (less than 30 days)	**$ 99,274**	$ 169,500
31-60 days	**567**	1,199
61-90 days	**103**	342
Past due (more than 90 days)	**1,826**	2,721
	$ 101,770	$ 173,762

CORPORATE INFORMATION

BOARD OF DIRECTORS

Mark R. Bly (2)(3)
Chair of the Board

Edward D. LaFehr
Director

Trudy M. Curran (2)(4)
Director

Naveen Dargan (1)(3)
Director

Don G. Hrap (3)
Director

Jennifer A. Maki (1)(2)
Director

Gregory K. Melchin (1)(4)
Director

David L. Pearce (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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OFFICERS

Edward D. LaFehr
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Rodney D. Gray
Executive Vice President and
Chief Financial 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

Chad E. Lundberg
Vice President, Light Oil

AUDITORS

KPMG LLP

RESERVES ENGINEERS

McDaniel & Associates Consultants Ltd.

TRANSFER AGENT

Computershare Trust Company of Canada

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE