TSX BTE | NYSE BTE

2020

Q1 Report

BAYTEX

BAYTEX ANNOUNCES FIRST QUARTER 2020 FINANCIAL AND OPERATING RESULTS

CALGARY, ALBERTA (May 7, 2020) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months ended March 31, 2020 (all amounts are in Canadian dollars unless otherwise noted).

“As an industry, we are facing an unprecedented challenge due to the effects of COVID-19 and the significant degradation and volatility in global crude oil prices. In response, Baytex has moved to ensure the safety and health of our people and to maintain liquidity, minimize capital outlays and emphasize cost reductions across all facets of our business. We have taken actions to achieve $135 million of cost reductions and have shut-in approximately 25,000 boe/d of production, which will have a positive impact on our adjusted funds flow and financial liquidity,” commented Ed LaFehr, President and Chief Executive Officer.

Q1 2020 Highlights

- Generated production of 98,452 boe/d (83% oil and NGL).
- Delivered adjusted funds flow of $133 million ($0.24 per basic share).
- Issued US$500 million principal amount of 8.75% senior unsecured notes due April 1, 2027.
- Redeemed US$400 million principal amount of 5.125% senior unsecured notes due 2021 and $300 million principal amount of 6.625% senior unsecured notes due 2022.
- Extended the maturity of our credit facilities to April 2, 2024. The credit facilities total approximately $1.1 billion and do not require annual or semi-annual reviews.
- Maintained undrawn credit capacity of $417 million and liquidity, net of working capital, of $315 million.

2020 Outlook

We previously announced a 50% reduction in our capital spending for this year to $260 to $290 million, from $500 to $575 million. With this revised capital program, we have suspended drilling and completion operations in Canada and expect to see a moderated pace of activity in the Eagle Ford. We are also intensely focused on driving further efficiencies in our operations. We have taken actions to achieve $135 million of cost reductions for 2020 relating to operating, transportation and general & administrative expenses.

In order to optimize the value of our resource base, we are voluntarily shutting-in approximately 25,000 boe/d of production (3,500 boe/d previously) of which 80% is heavy oil. At current commodity prices, the shut-in of these barrels will have a positive impact on our adjusted funds flow and improve our financial liquidity. Our current expectation is that the majority of these volumes will remain off-line for the balance of this year. Should operating netbacks change, we have the ability to shut-in additional volumes or restart wells in short order. Taking into account the incremental shut-in volumes, we have revised our production guidance range for 2020 to 70,000 to 74,000 boe/d, from 85,000 to 89,000 boe/d previously.

The situation around the COVID-19 virus continues to evolve. We have implemented a number of measures to foster resilience through these unpredictable times, including a work-from-home program and altering shifts in the field. We are focused on protecting the health and safety of our personnel while maintaining our operations and, to date, have had no positive cases of COVID-19 within the company.

	Three Months Ended		
	March 31, 2020	December 31, 2019	March 31, 2019
FINANCIAL (thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales	**$ 336,614**	$ 445,895	$ 453,424
Adjusted funds flow [(1)]	**132,935**	232,147	220,770
Per share - basic	**0.24**	0.42	0.40
Per share - diluted	**0.24**	0.42	0.40
Net income (loss)	**(2,498,217)**	(117,772)	11,336
Per share - basic	**(4.46)**	(0.21)	0.02
Per share - diluted	**(4.46)**	(0.21)	0.02
Capital Expenditures			
Exploration and development expenditures [(1)]	**$ 176,777**	$ 153,117	$ 153,843
Acquisitions, net of divestitures	**(40)**	563	-
Total oil and natural gas capital expenditures	**$ 176,737**	$ 153,680	$ 153,843
Net Debt			
Bank loan [(2)]	**$ 678,740**	$ 506,471	$ 550,751
Long-term notes [(2)]	**1,270,800**	1,337,200	1,569,153
Long-term debt	**1,949,540**	1,843,671	2,119,904
Working capital deficiency	**102,077**	28,120	55,337
Net debt [(1)]	**$ 2,051,617**	$ 1,871,791	$ 2,175,241
Shares Outstanding - basic (thousands)			
Weighted average	**559,804**	558,228	555,438
End of period	**560,483**	558,305	555,872
BENCHMARK PRICES			
Crude oil			
WTI (US$/bbl)	**$ 46.17**	$ 56.96	$ 54.90
MEH oil (US$/bbl)	**49.54**	60.04	60.46
MEH oil differential to WTI (US$/bbl)	**3.37**	3.08	5.56
Edmonton par ($/bbl)	**51.43**	68.10	66.53
Edmonton par differential to WTI (US$/bbl)	**(7.92)**	(5.37)	(4.85)
WCS heavy oil ($/bbl)	**34.48**	54.29	56.64
WCS differential to WTI (US$/bbl)	**(20.53)**	(15.83)	(12.29)
Natural gas			
NYMEX (US$/mmbtu)	**$ 1.95**	$ 2.50	$ 3.15
AECO ($/mcf)	**2.14**	2.34	1.94
CAD/USD average exchange rate	**1.3445**	1.3201	1.3293

	Three Months Ended		
	March 31, 2020	December 31, 2019	March 31, 2019
OPERATING			
Daily Production			
Light oil and condensate (bbl/d)	**45,717**	43,906	45,048
Heavy oil (bbl/d)	**28,854**	27,050	26,891
NGL (bbl/d)	**7,822**	8,699	11,729
Total liquids (bbl/d)	**82,393**	79,655	83,668
Natural gas (mcf/d)	**96,356**	100,235	104,682
Oil equivalent (boe/d @ 6:1) (3)	**98,452**	96,360	101,115
Netback (thousands of Canadian dollars)			
Total sales, net of blending and other expense (4)	**$ 315,257**	$ 427,728	$ 436,636
Royalties	**(56,720)**	(77,282)	(81,325)
Operating expense	**(104,470)**	(99,573)	(100,292)
Transportation expense	**(10,342)**	(8,840)	(13,330)
Operating netback (1)	**$ 143,725**	$ 242,033	$ 241,689
General and administrative	**(9,775)**	(9,893)	(14,136)
Cash financing and interest	**(28,535)**	(24,389)	(28,184)
Realized financial derivatives gain (loss)	**26,850**	22,956	18,814
Other (5)	**670**	1,440	2,587
Adjusted funds flow (1)	**$ 132,935**	$ 232,147	$ 220,770
Netback (per boe)			
Total sales, net of blending and other expense (4)	**$ 35.19**	$ 48.25	$ 47.98
Royalties	**(6.33)**	(8.72)	(8.94)
Operating expense	**(11.66)**	(11.23)	(11.02)
Transportation expense	**(1.15)**	(1.00)	(1.46)
Operating netback (1)	**$ 16.05**	$ 27.30	$ 26.56
General and administrative	**(1.09)**	(1.12)	(1.55)
Cash financing and interest	**(3.19)**	(2.75)	(3.10)
Realized financial derivatives gain (loss)	**3.00**	2.59	2.07
Other (5)	**0.07**	0.16	0.28
Adjusted funds flow (1)	**$ 14.84**	$ 26.18	$ 24.26

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, current income tax expense or recovery and payments on onerous contracts. Refer to the Q1/2020 MD&A for further information on these amounts.

Q1/2020 Results

Market conditions changed dramatically over the course of the first quarter and we moved quickly to adjust our business plan. We curtailed exploration and development spending in March, which resulted in first quarter capital spending of $177 million, 12% lower than our original expectation of $200 million. Approximately 70% of our capital was directed toward our operated assets in Canada, where we had an active program in both the Viking and Heavy Oil.

We successfully executed our first quarter drilling program and delivered operating results consistent with our expectations. We participated in the drilling of 124 (108.0 net) oil wells with a 100% success rate during the first quarter.

Production during the first quarter averaged 98,452 boe/d (83% oil and NGL), as compared to 96,360 boe/d (83% oil and NGL) in Q4/2019. Production in Canada averaged 62,262 boe/d (87% oil and NGL), as compared to 57,794 boe/d in Q4/2019, while production in the Eagle Ford averaged 36,190 boe/d (77% oil and NGL), as compared to 38,566 boe/d in Q4/2019.

We delivered adjusted funds flow of $133 million ($0.24 per basic share) in Q1/2020 and generated an operating netback of $16.05/boe. The Eagle Ford generated an operating netback of $22.78/boe and our Canadian operations generated an operating netback of $12.12/boe.

We identified indicators of impairment in Q1/2020 due to the sharp decline in crude oil prices and the economic uncertainty associated with the COVID-19 pandemic. As a result, we recorded total impairments of $2,716 million as the carrying value of our oil and gas properties exceeded their recoverable amounts. This impairment resulted in a net loss of $2,498 million in the first quarter. Revisions to forecast crude oil prices could result in reversals or additional impairment charges in the future.

Eagle Ford and Viking Light Oil

In the Eagle Ford, strong well performance continued across our acreage position. In Q1/2020, we participated in the drilling of 17 (3.8 net) wells and commenced production from 30 (6.1 net) wells. The wells brought on-stream during Q1/2020 generated an average 30-day initial production rate of approximately 1,875 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 24,696 boe/d (92% oil and NGL) during Q1/2020, as compared to 22,050 boe/d in Q4/2019. In Q1/2020, we invested $79 million on exploration and development in the Viking and commenced production from 83 (78.5 net) wells. We have suspended all drilling and completion activity in the Viking. We have also voluntarily shut-in approximately 15% of our Viking production for the months of April and May. These shut-in volumes will be evaluated monthly and we currently anticipate production resuming in the second half of the year.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 31,211 boe/d (93% oil and NGL) during the first quarter, as compared to 29,707 boe/d in Q4/2019. In Q1/2020, we invested $37 million on exploration and development, drilled 33 (33.0 net) wells and commenced production from 2 (2.0 net) wells. We have suspended all drilling and completion activity at Peace River and Lloydminster. We have also voluntarily shut-in approximately two-thirds of our heavy oil production, most of which we expect will remain off-line for the balance of this year.

Across all of our core assets, inventory enhancement continues to be a priority. We are also committed to building and maintaining respectful relationships with Indigenous communities and creating opportunities for meaningful economic participation and inclusion. During Q1/2020, we executed a strategic agreement with the Peavine Metis settlement in the Peace River area that covers 60 sections of land directly to the south of our existing Seal operations. We have identified significant potential for this early stage exploratory play targeting the Spirit River formation, a Clearwater formation equivalent, with first activity planned on the lands for 2021.

East Duvernay Shale Light Oil

Production in the East Duvernay Shale averaged 1,799 boe/d (81% oil and NGL) during Q1/2020, as compared to 1,305 boe/d in Q4/2019. 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 indefinitely and production in the field has been voluntarily shut-in for April and May.

Financial Liquidity

During the first quarter, we enhanced our long-term note maturity schedule which provides us with improved flexibility and liquidity.

- On February 5, 2020, we issued US$500 million principal amount of 8.75% senior unsecured notes maturing April 1, 2027.
- On February 20, 2020, we redeemed US$400 million principal amount of 5.125% senior unsecured notes due June 1, 2021 at par.
- On March 6, 2020, we redeemed $300 million principal amount of 6.625% senior unsecured notes due July 19, 2022 at 101.104% of the principal amount.
- Following these redemptions, our first long-term note maturity of US$400 million is not until June 2024.

We also extended the maturities of our credit facilities to April 2, 2024. The credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews. As of March 31, 2020, we had $417 million of undrawn capacity on our credit facilities resulting in approximately $315 million of liquidity net of working capital.

Our net debt, which includes our bank loan, long-term notes and working capital, totaled $2.1 billion at March 31, 2020.

Financial Covenants

The following table summarizes the financial covenants applicable to the credit facilities and Baytex's compliance therewith as at March 31, 2020.

Covenant Description	Position as at March 31, 2020	Covenant
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	0.8:1.00	3.50:1.00
Interest Coverage (3) (Minimum Ratio)	8.6:1.00	2.00:1.00

Notes:

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at March 31, 2020, the Company's Senior Secured Debt totaled $694.9 million which includes $678.7 million of principal amounts outstanding and $16.2 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 March 31, 2020 was $923.8 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 expenses, excluding accretion of debt issue costs and asset retirement obligations, for the twelve months ended March 31, 2020 were $107.2 million

Risk Management

To manage commodity price movements we utilize various financial derivative contracts and crude-by-rail to reduce the volatility in our adjusted funds flow. We realized a financial derivatives gain of $27 million in Q1/2020.

For the remainder of 2020, we have entered into hedges on the majority of our net crude oil exposure. This is comprised of WTI-based fixed price swaps on 2,000 bbl/d at US$58.00/bbl and a 3-way option structure on 24,500 bbl/d that at current oil prices will see Baytex receive WTI plus US$7.60/bbl.

We have also entered into additional financial hedges to mitigate the volatility in our adjusted funds flow for the next few months. This includes hedging 11,267 bbl/d at a weighted average price of US$25.43/bbl for Q2/2020 and 20,695 bbl/d at a weighted average price of $24.56/bbl for July.

For the remainder of 2020, we also have WTI-MSW basis differential swaps for 6,388 bbl/d of our light oil production in Canada at US$5.95/bbl and WCS differential hedges on 6,500 bbl/d at a WTI-WCS differential of US$16.27/bbl.

Crude-by-rail is an integral part of our egress and marketing strategy for our heavy oil production. For 2020, we had originally contracted to deliver approximately 11,500 bbl/d of our heavy oil volumes to market by rail. In the current pricing environment, we expect our crude-by-rail volumes to be significantly reduced.

A complete listing of our financial derivative contracts can be found in Note 17 to our Q1/2020 financial statements.

2020 Guidance

We have updated our production and cost assumptions to reflect the impact of voluntarily shutting-in approximately 25,000 boe/d of production (3,500 boe/d previously). At current commodity prices, we expect the majority of the shut-in volumes to remain off-line for the balance of this year. The shut-in of these barrels is expected to have a positive impact on our adjusted funds flow and improve our financial liquidity.

We continue to emphasize cost reductions across all facets of our organization. We have identified approximately $135 million of cost reductions for 2020 (operating, transportation and general & administrative expenses). 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. In addition, we are realizing an approximate 25% reduction in transportation expenses due to reduced volumes.

We are reducing our general and administrative expense guidance by 11% to $40 million. As a continued cost control measure, all full-time employee salaries and all annual retainers paid to our directors were reduced by 10% effective April 1, 2020.

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

	2020 Guidance (1)	2020 Revised Guidance
Exploration and development expenditures	$260 - $290 million	no change
Production (boe/d)	85,000 - 89,000	70,000 - 74,000
Expenses:		
Royalty rate	19.0 - 19.5%	~ 20%
Operating	$11.75 - $12.50/boe	no change
Transportation	$1.10 - $1.20/boe	$0.80 - $0.90/boe
General and administrative	$45 million ($1.42/boe)	$40 million ($1.52/boe)
Interest	$115 million ($3.62/boe)	$120 million ($4.57/boe)
Leasing expenditures	$7 million	no change
Asset retirement obligations	$10 million	no change

Note:

(1) As announced on March 18, 2020.

NYSE Listing Notification and Extension

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.

Under the NYSE’s rules, Baytex can avoid delisting if, within six months from the date of the NYSE notification, 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. On April 21, 2020, the NYSE announced temporary relief to provide noncompliant issuers additional time to cure the noncompliance. As a result, the NYSE has provided Baytex an extension to December 3, 2020 (from September 24, 2020). If at the expiration of this date, Baytex has not regained compliance, the NYSE will commence suspension and delisting procedures.

The NYSE can also commence accelerated delisting action in the event Baytex's common shares trade at levels viewed by the NYSE to be abnormally low, which the NYSE has advised is typically below US$0.16 per share. At this time, Baytex does not expect to propose a share consolidation as a means of curing the deficiency.

Non-compliance with the NYSE's price listing standard does not affect Baytex's business operations or its reporting requirements to the U.S. Securities and Exchange Commission (the "SEC"), nor does it affect the continued listing and trading of Baytex's common shares on the Toronto Stock Exchange (the "TSX").

Baytex's common shares will continue to be listed and traded on the NYSE during the applicable cure period, subject to continued compliance with the NYSE's other continued listing standards, under the symbol "BTE", but the NYSE has assigned a ".BC" indicator to the symbol to denote that Baytex is below the NYSE's price listing standard. This indicator will be removed at such time as Baytex is deemed compliant with the NYSE's price listing standard.

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

Baytex will host a conference call tomorrow, May 8, 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/baytexq120200508.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.

Additional Information

Our condensed consolidated interim unaudited financial statements for the three months ended March 31, 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.

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 "anticipate", "believe", "continue", "could", "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; our objective to ensure the health and safety of our people, maintain financial liquidity, deploy capital efficiently and emphasize cost reductions; that we expect to see moderated activity in the Eagle Ford and our expectations for $135 million of cost reductions; that the majority of shut-in barrels will be shut-in for the balance of the year; our ability to re-start shut in wells or shut-in additional volumes; our revised production guidance range; that we will re-evaluate our shut-in Viking production monthly and anticipate production resuming in H2 2020; that we expect shut-in heavy oil production to be shut-in for the rest of 2020; activity is planned for our Peavine Metis lands in 2021; that a majority of our net crude oil exposure is hedged for 2020; that we expect to significantly reduce our crude-by-rail volumes; that shut-in barrels are expected to have a positive impact on our adjusted funds flow and improve our liquidity; our revised 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; and our expectations with respect to the potential de-listing our shares from the NYSE.

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, EBITDA, exploration and development expenditures, 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, EBITDA, exploration and development expenditures, 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 months ended March 31, 2020.

EBITDA is not a measurement based on GAAP in Canada. EBITDA is defined as net income or loss adjusted for financing and interest expenses, unrealized gains and losses on financial derivatives, income tax, non-recurring losses, payments on lease obligations, certain specific unrealized and non-cash transactions (including depletion, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation).

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.

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 quarter ended March 31, 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.

	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	14,019	9	13	12,622	16,145
Lloydminster	14,835	18	—	1,280	15,067
Canada - Light					
Viking	—	22,485	114	12,583	24,696
Duvernay	—	929	521	2,093	1,799
Remaining properties	—	800	670	18,521	4,556
United States					
Eagle Ford	—	21,476	6,505	49,256	36,190
Total	28,854	45,717	7,822	96,356	98,452

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 months ended March 31, 2020 and 2019
Dated May 7, 2020

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three months ended March 31, 2020. This information is provided as of May 7, 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 months ended March 31, 2020 ("Q1/2020") have been compared with the results for the three months ended March 31, 2019 ("Q1/2019"). This MD&A should be read in conjunction with the Company's condensed consolidated interim financial statements ("consolidated financial statements") for the three months ended March 31, 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", "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 of 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 has resulted in an unprecedented collapse in global crude oil prices.

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 evolves. 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 government and public health agencies. We have also taken steps to preserve our financial liquidity during this time of heightened uncertainty. We have taken action to achieve $135 million of cost reductions for 2020 relating to operating, transportation and general and administrative expenses. This includes a 10 percent reduction in salaries for all full time employees and a reduction of annual retainers paid to our directors effective April 1, 2020. 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 have 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.

The global health crisis surrounding COVID-19 has impacted our results for Q1/2020 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.

We are expecting compliance with the financial covenants applicable to our credit facilities for at least the next twelve months. 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 ensure their availability. There is no certainty that we will be successful in negotiating such amendments.

FIRST QUARTER HIGHLIGHTS

We had strong operating results for Q1/2020 despite the impact of COVID-19. We invested $176.8 million on exploration and development expenditures, generated production of 98,452 boe/d and adjusted funds flow of $132.9 million. Capital spending and production were reduced for Q1/2020 in response to the sharp decline in crude oil prices due to the COVID-19 health crisis and the OPEC+ price war. The decline in crude oil prices also resulted in an impairment being recorded in Q1/2020 which impacted our earnings. We also took significant actions to improve our financial liquidity with the issuance of senior notes due 2027 and extending the maturity date of our credit facilities to 2024.

Proceeds from the issuance of senior notes were used in conjunction with availability on our credit facilities to complete the early redemption of the US$400 million principal amount of 5.125% senior notes due in 2021 and the early redemption of the $300 million principal amount of 6.625% senior notes due in 2022. As a result of these actions we do not have any debt maturities until 2024 and we maintained over $400 million undrawn capacity on our credit facilities at March 31, 2020.

In Canada, production was 62,262 boe/d for Q1/2020 which is 4% higher than 60,018 boe/d in Q1/2019 and reflects our successful capital program. Exploration and development expenditures of $123.1 million in Q1/2020 were primarily focused on our Viking light oil property along with additional heavy oil development at Lloydminster and Peace River. Exploration and development expenditures 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 and 33 (33.0 net) heavy oil wells during Q1/2020.

In the U.S., we invested $53.7 million on exploration and development activity during Q1/2020 and drilled 17 (3.8 net) wells and commenced production from 30 (6.1 net) wells. Production was 36,190 boe/d for Q1/2020 and reflects lower completion activity on our lands relative to Q1/2019 when production was 41,097 boe/d and we commenced production from 36 (8.9 net) wells.

Commodity prices were relatively strong as Q1/2020 began with the West Texas Intermediate ("WTI") benchmark price averaging US$57.53/bbl in January. Decisions made by the leaders of Saudi Arabia and Russia to increase production of crude oil as demand was falling due to the spread of COVID-19 resulted in a sharp decline in global crude oil prices with WTI averaging US$30.45/bbl in March. As a result the WTI benchmark price averaged US$46.17/bbl for Q1/2020 compared to US$54.90/bbl during Q1/2019.

Adjusted funds flow was $132.9 million in Q1/2020 compared to $220.8 million for Q1/2019. Strong production results in Q1/2020 were overshadowed by the beginning of an unprecedented decline in crude oil prices which was the key factor contributing to a $98.0 million decrease in operating netback relative to Q1/2019. Partially offsetting the decline in operating netback was a $4.4 million reduction in general administrative expenses along with an $8.0 million increase in realized gains on financial derivatives in Q1/2020 compared to Q1/2019.

In Q1/2020 we reported a net loss of $2.5 billion compared to net income of $11.3 million in Q1/2019. The net loss recorded for Q1/2020 includes impairment expense of $2.7 billion which is directly attributable to the significant decline in forecasted prices for crude oil at March 31, 2020 relative to December 31, 2019.

Net debt was $2.1 billion at March 31, 2020 compared to $1.9 billion at December 31, 2019. The increase in net debt is primarily the result of a $110.7 million increase in the reported amount of our U.S. dollar denominated net debt due to a weaker Canadian dollar at March 31, 2020 along with exploration and development expenditures that exceeded adjusted funds flow by $43.8 million.

2020 GUIDANCE

We have updated our production and cost assumptions to reflect the impact of voluntarily shutting-in approximately 25,000 boe/d of production. At current commodity prices, we expect the majority of shut-in volumes to remain off-line for the balance of this year. The shut-in of these barrels is expected to have a positive impact on our adjusted funds flow and improve our financial liquidity.

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. In addition, we are realizing an approximate 25% reduction in transportation expenses due to reduced volumes.

We are reducing our general and administrative expense guidance by 11% to $40 million. As a continued cost control measure, all full-time employee salaries and all annual retainers paid to our directors were reduced by 10% effective April 1, 2020.

The following table compares our updated 2020 guidance to our previously announced guidance and our Q1/2020 results.

	Previous Annual Guidance [1]	Revised Annual Guidance	Q1/2020 Results
Exploration and development expenditures ($ millions)	$260 - $290	no change	$176.8
Production (boe/d)	85,000 - 89,000	70,000 - 74,000	98,452
Expenses:			
Royalty rate (%)	19.0 - 19.5	~20.0	18.0
Operating ($/boe)	$11.75 - $12.50	no change	$11.66
Transportation ($/boe)	$1.10 - $1.20	$0.80 - $0.90	$1.15
General and administrative ($ millions)	$45 ($1.42/boe)	$40 ($1.52/boe)	$9.8 ($1.09/boe)
Cash interest ($ millions)	$115 ($3.62/boe)	$120 ($4.57/boe)	$28.5 ($3.19/boe)
Leasing expenditures ($ millions)	$7	no change	$1.5
Asset retirement obligations ($ millions)	$10	no change	$4.2

(1) As announced on March 18, 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 March 31					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**24,241**	**21,476**	**45,717**	23,295	21,753	45,048
Heavy oil	**28,854**	**—**	**28,854**	26,891	—	26,891
Natural Gas Liquids (NGL)	**1,317**	**6,505**	**7,822**	1,608	10,121	11,729
Total liquids (bbl/d)	**54,412**	**27,981**	**82,393**	51,794	31,874	83,668
Natural gas (mcf/d)	**47,100**	**49,256**	**96,356**	49,346	55,336	104,682
Total production (boe/d)	**62,262**	**36,190**	**98,452**	60,018	41,097	101,115
Production Mix						
Light oil and condensate	**39 %**	**59 %**	**46 %**	39 %	53 %	45 %
Heavy oil	**46 %**	**— %**	**29 %**	45 %	— %	27 %
NGL	**2 %**	**18 %**	**8 %**	3 %	25 %	12 %
Natural gas	**13 %**	**23 %**	**17 %**	13 %	22 %	16 %

Production of 98,452 boe/d for Q1/2020 reflects strong operational performance in the U.S. and Canada. Production results were in line with our expectations prior to suspending our Canadian capital program and shutting-in production in response to the sharp decline in global crude oil prices in March. In mid-March we began shutting-in low or negative margin production which had a minimal impact on reported production for Q1/2020. With the extreme volatility in oil prices, we are making decisions to produce or shut-in volumes on a month-to-month basis. While we expect our production to be lower for the remainder of 2020 we have the ability to quickly restore production from shut-in wells when commodity prices are supportive. These actions are reflected in our revised annual guidance range of 70,000 - 74,000 boe/d for 2020.

In Canada, production was 62,262 boe/d for Q1/2020 compared to 60,018 boe/d in Q1/2019. The increase in production in Q1/2020 relative to Q1/2019 is primarily due to strong well performance from our development program. We were more active on our Canadian properties coming into Q1/2020 relative to Q1/2019 when our activity was reduced in response to a significant widening of Canadian light and heavy oil differentials in Q4/2018.

Production in the U.S. was 36,190 boe/d for Q1/2020 compared to 41,097 boe/d for Q1/2019. U.S. production for Q1/2020 was lower than for Q1/2019 due to lower completion activity on our lands relative to the same period of 2019. We initiated production from 30 (6.1 net) wells during Q1/2020 compared to 36 (8.9 net) wells in Q1/2019.

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 Q1/2020 as stable demand and production outlooks continued from Q4/2019. Benchmark prices began to decline rapidly in March 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 has continued into 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 continues 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$49.54/bbl during Q1/2020 which is a US$3.37/bbl premium to WTI as compared to US$60.46/bbl or a US$5.56/bbl premium to WTI in Q1/2019. The MEH benchmark premium to WTI was lower in Q1/2020 compared to Q1/2019 as a result of an increase in supply at the Magellan East terminal due to higher oil production in Texas relative to Q1/2019.

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 Q1/2020 compared to Q1/2019. 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 Q1/2020

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 $51.43/bbl which is a US$7.92/bbl discount to WTI for Q1/2020 compared to $66.53/bbl which is a US$4.85/bbl discount to WTI for Q1/2019.

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 $34.48/bbl or a US$20.53/bbl differential to WTI in Q1/2020 as compared to $56.64/bbl or a differential of US$12.29/bbl for Q1/2019.

Natural Gas

U.S. natural gas prices for Q1/2020 were lower than Q1/2019 as higher U.S. natural gas production has outpaced growth in natural gas demand. Canadian natural gas prices remained challenged during Q1/2020 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$1.95/mmbtu in Q1/2020 which is lower compared to US$3.15/mmbtu in Q1/2019. Increasing natural gas production levels in the U.S. resulted in an oversupplied North American market and lower natural gas prices in Q1/2020 relative to Q1/2019.

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 $2.14/mcf during Q1/2020 which is higher than $1.94/mcf for Q1/2019.

The following tables compare select benchmark prices and our average realized selling prices for the three months ended March 31, 2020 and 2019.

	Three Months Ended March 31		
	2020	2019	Change
Benchmark Averages			
WTI oil (US$/bbl)[1]	**46.17**	54.90	(8.73)
MEH oil (US$/bbl)[2]	**49.54**	60.46	(10.92)
MEH oil differential to WTI (US$/bbl)	**3.37**	5.56	(2.19)
Edmonton par oil ($/bbl)	**51.43**	66.53	(15.10)
Edmonton par oil differential to WTI (US$/bbl)	**(7.92)**	(4.85)	(3.07)
WCS heavy oil ($/bbl)[3]	**34.48**	56.64	(22.16)
WCS heavy oil differential to WTI (US$/bbl)	**(20.53)**	(12.29)	(8.24)
AECO natural gas price ($/mcf)[4]	**2.14**	1.94	0.20
NYMEX natural gas price (US$/mmbtu)[5]	**1.95**	3.15	(1.20)
CAD/USD average exchange rate	**1.3445**	1.3293	0.0152

(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 March 31					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)	**$ 49.45**	**$ 61.99**	**$ 55.34**	$ 63.14	$ 76.06	$ 69.38
Heavy oil ($/bbl)[1]	**20.75**	**—**	**20.75**	41.69	—	41.69
NGL ($/bbl)	**11.25**	**14.94**	**14.31**	23.77	22.84	22.97
Natural gas ($/mcf)	**2.00**	**2.63**	**2.32**	2.37	3.95	3.21
Weighted average ($/boe)[1]	**$ 30.62**	**$ 43.05**	**$ 35.19**	$ 45.77	$ 51.20	$ 47.98

(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 $35.19/boe for Q1/2020 compared to $47.98/boe for Q1/2019. Our realized price in the U.S. was $43.05/boe in Q1/2020 which is $8.15/boe lower than $51.20/boe in Q1/2019 due to the decrease in U.S. commodity benchmark prices. In Canada, our realized price of $30.62/boe for Q1/2020 was $15.15/boe lower than $45.77/boe for Q1/2019 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 $49.45/bbl in Q1/2020 compared to $63.14/bbl in Q1/2019. Our realized light oil and condensate price for Q1/2020 represents a discount of $1.98/bbl to the Edmonton par price which is narrower than a discount of $3.39 in Q1/2019 due to improved price realizations on our Viking light oil production.

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 $61.99/bbl for Q1/2020 compared to $76.06/bbl for Q1/2019. Expressed in U.S. dollars, our realized light oil and condensate price of US$46.11/bbl for Q1/2020 reflects a US$3.43 discount to the MEH benchmark for Q1/2020 which is relatively consistent with the US$3.24 discount for Q1/2019.

Our realized heavy oil price, net of blending and other expense averaged $20.75/bbl in Q1/2020 compared to $41.69/bbl in Q1/2019. Our realized heavy oil price for Q1/2020 was $20.94/bbl lower than Q1/2019 which is relatively consistent with the $22.16/bbl decrease in the WCS benchmark price over the same period.

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 $14.31/bbl in Q1/2020 or 23% of WTI (expressed in Canadian dollars) compared to $22.97/bbl or 31% of WTI (expressed in Canadian dollars) in Q1/2019. The decrease in our NGL price realization as a percentage of WTI for Q1/2020 relative to Q1/2019 is a result of increased NGL production and supply which resulted in lower benchmark pricing for NGLs relative to WTI.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price of $2.00/mcf for Q1/2020 and $2.37/mcf in Q1/2019 is relatively consistent with the AECO benchmark price in both periods. In the U.S., our realized natural gas price was US$1.96/mcf for Q1/2020 compared to US$2.97/mcf in Q1/2019 which is relatively consistent with the NYMEX benchmark in both periods.

Petroleum and Natural Gas Sales

	Three Months Ended March 31					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 109,084**	**$ 121,155**	**$ 230,239**	$ 132,368	$ 148,916	$ 281,284
Heavy oil	**75,843**	**—**	**75,843**	117,686	—	117,686
NGL	**1,348**	**8,842**	**10,190**	3,441	20,802	24,243
Total oil sales	**186,275**	**129,997**	**316,272**	253,495	169,718	423,213
Natural gas sales	**8,569**	**11,773**	**20,342**	10,544	19,667	30,211
Total petroleum and natural gas sales	**194,844**	**141,770**	**336,614**	264,039	189,385	453,424
Blending and other expense	**(21,357)**	**—**	**(21,357)**	(16,788)	—	(16,788)
Total sales, net of blending and other expense	**$ 173,487**	**$ 141,770**	**$ 315,257**	$ 247,251	$ 189,385	$ 436,636

Total sales, net of blending and other expense, of $315.3 million for Q1/2020 decreased $121.4 million from $436.6 million reported for Q1/2019. The decrease in total sales in Q1/2020 relative to Q1/2019 is primarily due to lower realized pricing as a result of the decrease in benchmark pricing along with lower production for Q1/2020 relative to Q1/2019.

In Canada, total sales, net of blending and other expense, was $173.5 million for Q1/2020 which is a decrease of $73.8 million from Q1/2019. Total petroleum and natural gas sales decreased from lower realized pricing for Q1/2020. Our average realized price of $30.62/boe for Q1/2020 was lower than $45.77/boe for Q1/2019 due to the decrease in benchmark pricing for our production in Canada and resulted in a $85.9 million decrease in total sales, net of blending and other expense. Production in Canada was 2,244 boe/d higher in Q1/2020 which resulted in a $12.1 million increase in total sales, net of blending and other expense relative to Q1/2019.

In the U.S., petroleum and natural gas sales were $141.8 million for Q1/2020 which is a decrease of $47.6 million from $189.4 million reported for Q1/2019. Our realized price for Q1/2020 was $8.15/boe lower than Q1/2019 and resulted in a $26.9 million decrease in total petroleum and natural gas sales. Lower completion activity on our lands during Q1/2020 resulted in a 4,907 boe/d decrease in production and a $20.8 million decrease in total sales, net of blending and other expense relative to Q1/2019.

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 months ended March 31, 2020 and 2019.

	Three Months Ended March 31					
	2020			2019		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 15,518**	**$ 41,202**	**$ 56,720**	$ 25,184	$ 56,141	$ 81,325
Average royalty rate[1]	**8.9 %**	**29.1 %**	**18.0 %**	10.2 %	29.6 %	18.6 %
Royalties per boe	**$ 2.74**	**$ 12.51**	**$ 6.33**	$ 4.66	$ 15.18	$ 8.94

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

Total royalties in Q1/2020 were $56.7 million or 18.0% of total sales, net of blending and other expense compared to $81.3 million or 18.6% in Q1/2019. A lower proportion of our production was from our U.S. properties in Q1/2020 compared to Q1/2019 which resulted in a lower royalty rate as our U.S. properties have a higher royalty rate than our Canadian properties. Total royalty expense is lower in Q1/2020 primarily due to the decrease in petroleum and natural gas sales relative to Q1/2019. Our revised annual guidance of approximately 20% for 2020 reflects a higher proportion of our production coming from our U.S. assets for the remainder of the year.

Our Canadian royalty rate of 8.9% for Q1/2020 was lower than 10.2% for Q1/2019 due to lower benchmark pricing which resulted in a lower royalty rate on certain heavy oil production in Q1/2020 relative to Q1/2019. In the U.S., royalties for Q1/2020 were 29.1% of total petroleum and natural gas sales which is consistent with Q1/2019 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

Operating Expense

	Three Months Ended March 31					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 78,922**	**$ 25,548**	**$ 104,470**	$ 74,102	$ 26,190	$ 100,292
Operating expense per boe	**$ 13.93**	**$ 7.76**	**$ 11.66**	$ 13.72	$ 7.08	$ 11.02

Operating expense was $104.5 million ($11.66/boe) for Q1/2020 compared to $100.3 million ($11.02/boe) in Q1/2019. The increase in total operating expense and operating expense per boe can be attributed to an increase in production from Canada in Q1/2020 relative to Q1/2019 and the decrease in U.S. production which has lower operating costs per boe. Operating expense of $11.66/boe is consistent with expectations and was slightly below our 2020 annual guidance range of $11.75 - $12.50/boe.

In Canada, operating expense was $78.9 million ($13.93/boe) for Q1/2020 compared to $74.1 million ($13.72/boe) for Q1/2019. Total operating expense in Canada has increased with higher production but has remained fairly consistent as per unit operating costs were $13.93/boe for Q1/2020 compared to $13.72/boe in Q1/2019.

U.S. operating expense was $25.5 million ($7.76/boe) for Q1/2020 compared to $26.2 million ($7.08/boe) for Q1/2019. Expressed in U.S. dollars, per unit operating expense was US$5.77/boe in Q1/2020 which reflects lower total production compared to Q1/2019 when per unit operating expense was US$5.33/boe as a portion of our operating costs in the U.S. are fixed and do not fluctuate with production.

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 months ended March 31, 2020 and 2019.

	Three Months Ended March 31					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 10,342**	**$ —**	**$ 10,342**	$ 13,330	$ —	$ 13,330
Transportation expense per boe	**$ 1.83**	**$ —**	**$ 1.15**	$ 2.47	$ —	$ 1.46

We reported transportation expense of $1.15/boe for Q1/2020 which is in line with expectations. Transportation expense was $10.3 million ($1.15/boe) for Q1/2020 compared to $13.3 million ($1.46/boe) for Q1/2019. The decrease in transportation expense for Q1/2020 is due to lower transportation costs for our light oil properties in Canada which resulted in lower aggregate and per unit transportation expense for Q1/2020. We expect transportation expense to be lower for the remainder of the year as we optimize our Canadian production in response to the low commodity price environment and have adjusted our annual guidance range to $0.80 - $0.90/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 $21.4 million for Q1/2020 compared to $16.8 million for Q1/2019. The increase in blending and other expense reflects the higher heavy oil production and volumes of blending condensate required in Q1/2020 relative to Q1/2019.

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 months ended March 31, 2020 and 2019.

	Three Months Ended March 31		
($ thousands)	**2020**	2019	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ 26,645**	$ 17,812	$ 8,833
Natural gas	**210**	966	(756)
Interest and financing	**(5)**	36	(41)
Total	**$ 26,850**	$ 18,814	$ 8,036
Unrealized financial derivatives gain (loss)			
Crude oil	**$ 99,809**	$ (51,166)	$ 150,975
Natural gas	**(122)**	(1,580)	1,458
Interest and financing	**(678)**	(515)	(163)
Equity total return swap ("Equity TRS")	**(3,014)**	—	(3,014)
Total	**$ 95,995**	$ (53,261)	$ 149,256
Total financial derivatives gain (loss)			
Crude oil	**$ 126,454**	$ (33,354)	$ 159,808
Natural gas	**88**	(614)	702
Interest and financing	**(683)**	(479)	(204)
Equity TRS	**(3,014)**	—	(3,014)
Total	**$ 122,845**	$ (34,447)	$ 157,292

We recorded total financial derivative gains of $122.8 million for Q1/2020 compared to total financial derivative losses of $34.4 million in Q1/2019. Realized financial derivatives gains of $26.9 million for Q1/2020 are primarily a result of the market prices for crude oil settling at levels below those set in our derivative contracts. The unrealized gain of $96.0 million for Q1/2020 reflects an increase in the fair value of unrealized derivative contracts due to a decrease in futures pricing for the remainder of 2020 at March 31, 2020 relative to December 31, 2019.

Realized gains on crude oil financial derivatives of $26.6 million in Q1/2020 are primarily a result of market prices for WTI settling at levels below the prices set in our contracts outstanding during the period. Our natural gas financial derivatives generated gains of $0.2 million in Q1/2020. These gains were a result of the NYMEX index for Q1/2020 averaging less than the fixed price on our NYMEX contracts in place.

Unrealized gains of $96.0 million in Q1/2020 are primarily a result of lower futures prices for crude oil for the remainder of 2020 relative to December 31, 2019 which resulted in unrealized gains of $99.8 million. We recorded an unrealized loss of $3.0 million on equity total return swaps used to fix the cost of certain employee incentive plans due to the decrease in our share price between the grant date of the associated awards and March 31, 2020. The fair value of our financial derivative contracts resulted in a net asset of $92.8 million at March 31, 2020 compared to a net liability of $3.2 million at December 31, 2019.

We had the following commodity financial derivative contracts as at May 7, 2020.

	Period	Volume	Price/Unit(1)	Index
Oil				
Basis Swap	Apr 2020 to Dec 2020	6,500 bbl/d	WTI less US$16.27/bbl	WCS
Basis Swap(7)	Jan 2021 to Dec 2021	2,000 bbl/d	WTI less US$14.12/bbl	WCS
Basis Swap	Apr 2020 to Dec 2020	5,000 bbl/d	WTI less US$6.15/bbl	MSW
MSW Stream(6)(7)	June 2020	800 bbl/d	$22.68/bbl	Blended
MSW Stream(6)(7)	July 2020	11,695 bbl/d	$27.17/bbl	Blended
Fixed - Sell	Apr 2020 to Dec 2020	2,000 bbl/d	US$58.00/bbl	WTI
Fixed - Sell(7)	Apr 2020 to June 2020	6,000 bbl/d	US$25.62/bbl	WTI
Fixed - Sell(7)	May 2020	6,000 bbl/d	$40.72/bbl	WTI-CAD
Fixed - Sell(7)	June 2020	3,000 bbl/d	US$22.55/bbl	WTI
Fixed - Sell(7)	June 2020	6,000 bbl/d	$32.45/bbl	WTI-CAD
Fixed - Sell(7)	July 2020	4,000 bbl/d	US$24.73/bbl	WTI
Fixed - Sell(7)	July 2020	5,000 bbl/d	$34.05/bbl	WTI-CAD
3-way option(2)	Apr 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$56.00/US$61.35	WTI
3-way option(2)	Apr 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$57.00/US$60.00	WTI
3-way option(2)	Apr 2020 to Dec 2020	4,500 bbl/d	US$50.00/US$57.00/US$62.00	WTI
3-way option(2)	Apr 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$58.00/US$62.00	WTI
3-way option(2)	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.50	WTI
3-way option(2)	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.83	WTI
3-way option(2)	Apr 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI
3-way option(2)	Apr 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI
3-way option(2)	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI
3-way option(2)	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI
3-way option(2)	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI
3-way option(2)	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI
3-way option(2)	Apr 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	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
Natural Gas				
Fixed - Sell	Apr 2020 to Dec 2020	5,000 GJ/d	$1.77/GJ	AECO 7A
Fixed - Sell(7)	May 2020 to Dec 2020	5,500 GJ/d	$2.22/GJ	AECO 7A
Fixed - Sell	Jan 2021 to Dec 2021	10,500 GJ/d	$2.31/GJ	AECO 7A
Fixed - Sell(7)	May 2020 to Dec 2020	2,500 GJ/d	$2.29/GJ	AECO 5A
Fixed - Sell(7)	Oct 2020 to Dec 2020	5,500 mmbtu/d	US$2.64/mmbtu	NYMEX
Fixed - Sell(7)	Jan 2021 to Dec 2021	9,000 mmbtu/d	US$2.72/mmbtu	NYMEX
3-way option(2)	Apr 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 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.

(7) Contracts entered subsequent to March 31, 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 months ended March 31, 2020 and 2019.

	Three Months Ended March 31					
	2020			2019		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**62,262**	**36,190**	**98,452**	60,018	41,097	101,115
Operating netback:						
Total sales, net of blending and other expense	**$ 30.62**	**$ 43.05**	**$ 35.19**	$ 45.77	$ 51.20	$ 47.98
Less:						
Royalties	**(2.74)**	**(12.51)**	**(6.33)**	(4.66)	(15.18)	(8.94)
Operating expense	**(13.93)**	**(7.76)**	**(11.66)**	(13.72)	(7.08)	(11.02)
Transportation expense	**(1.83)**	**—**	**(1.15)**	(2.47)	—	(1.46)
Operating netback	**$ 12.12**	**$ 22.78**	**$ 16.05**	$ 24.92	$ 28.94	$ 26.56
Realized financial derivatives gain	**—**	**—**	**3.00**	—	—	2.07
Operating netback after financial derivatives	**$ 12.12**	**$ 22.78**	**$ 19.05**	$ 24.92	$ 28.94	$ 28.63

Our operating netback after financial derivatives was $19.05/boe for Q1/2020 which was $9.58/boe lower than $28.63/boe for Q1/2019. Operating netback of $16.05/boe in Q1/2020 was lower than $26.56/boe in Q1/2019 due to the decrease in benchmark pricing in Canada and the U.S. which resulted in lower per unit sales net of royalties. Total operating and transportation expense of $12.81/boe in Q1/2020 is relatively consistent with $12.48/boe for the same period of 2019. Lower operating netback was partially offset by a $0.93/boe increase in realized gains on financial derivatives in Q1/2020 compared to Q1/2019.

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 months ended March 31, 2020 and 2019.

	Three Months Ended March 31		
($ thousands except for per boe)	**2020**	2019	Change
Gross general and administrative expense	**$ 11,888**	$ 15,619	$ (3,731)
Overhead recoveries	**(2,113)**	(1,483)	(630)
General and administrative expense	**$ 9,775**	$ 14,136	$ (4,361)
General and administrative expense per boe	**$ 1.09**	$ 1.55	$ (0.46)

G&A expense was $9.8 million ($1.09/boe) for Q1/2020 compared to $14.1 million ($1.55/boe) for Q1/2019. G&A expense for Q1/2020 was lower relative to Q1/2019 due to lower staffing and corporate administrative costs after we completed the integration of Raging River Exploration Inc. in early 2019. The decrease in G&A expense per boe in Q1/2020 relative to Q1/2019 reflects the efficiencies we were able to realize by combining the two organizations and is consistent with our expectations and guidance. Our revised annual guidance of $40 million ($1.52/boe) reflects a reduction in gross G&A expense from our cost savings initiatives along with lower overhead recoveries due to the reduction in exploration and development spending in Canada.

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 months ended March 31, 2020 and 2019.

	Three Months Ended March 31		
($ thousands except for per boe)	**2020**	2019	Change
Interest on credit facilities	**$ 4,135**	$ 5,412	$ (1,277)
Interest on long-term notes	**24,273**	22,602	1,671
Interest on lease obligations	**127**	170	(43)
Cash interest	**$ 28,535**	$ 28,184	$ 351
Accretion of debt issue costs	**4,442**	1,095	3,347
Accretion of asset retirement obligations	**2,931**	3,463	(532)
Early redemption expense	**3,312**	—	3,312
Financing and interest expense	**$ 39,220**	$ 32,742	$ 6,478
Cash interest per boe	**$ 3.19**	$ 3.10	$ 0.09
Financing and interest expense per boe	**$ 4.38**	$ 3.60	$ 0.78

Financing and interest expense was $39.2 million in Q1/2020 compared to $32.7 million in Q1/2019. Cash interest of $28.5 million ($3.19/boe) in Q1/2020 is consistent with $28.2 million ($3.10/boe) in Q1/2019. During Q1/2020, we issued US$500 million principal amount of 8.75% senior unsecured notes on February 5, 2020. 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 note on March 5, 2020. Total cash interest for Q1/2020 was consistent with Q1/2019 as a result of these transactions.

Financing and interest expense for Q1/2020 includes accelerated amortization of debt issue costs and $3.3 million of early redemption expense associated with the early redemption of the $300 million principal amount of 6.625% senior unsecured notes which were redeemed at 101.104% of the principal amount.

We expect cash financing and interest expense of $120 million ($4.57/boe) which reflects lower production for the remainder of 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 lease expiries, the accumulated costs of expiring leases and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense was $0.3 million for Q1/2020 and $1.8 million for Q1/2019.

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 months ended March 31, 2020 and 2019.

	Three Months Ended March 31		
($ thousands except for per boe)	**2020**	2019	Change
Depletion	**$ 179,418**	$ 184,844	$ (5,426)
Depreciation	**1,968**	510	1,458
Depletion and depreciation	**$ 181,386**	$ 185,354	$ (3,968)
Depletion and depreciation per boe	**$ 20.25**	$ 20.37	$ (0.12)

Depletion and depreciation expense was $181.4 million ($20.25/boe) for Q1/2020 compared to $185.4 million ($20.37/boe) for Q1/2019. Total depletion and depreciation expense was slightly lower in Q1/2020 due to a decrease in production in Q1/2020 compared to Q1/2019 as the depletion rate per boe was consistent in both periods.

Impairment

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 cash generating units ("CGU"). 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 $2,588.5 million related to the CGUs comprising oil and gas properties and $127.9 million 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, impairment 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 $2.8 million for Q1/2020 compared to $5.8 million for Q1/2019. Total SBC expense is lower in Q1/2020 as the total value of awards granted in 2020 was lower than prior years. The total expense for Q1/2020 is comprised of non-cash compensation expense of $2.3 million related to the Share Award Incentive Plan and cash compensation expense of $0.5 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 March 31		
($ thousands except for exchange rates)	**2020**	2019	Change
Unrealized foreign exchange loss (gain)	**$ 99,521**	$ (26,941)	$ 126,462
Realized foreign exchange loss (gain)	**371**	(595)	966
Foreign exchange loss (gain)	**$ 99,892**	$ (27,536)	$ 127,428
CAD/USD exchange rates:			
At beginning of period	**1.2965**	1.3646	
At end of period	**1.4120**	1.3360	

We recorded an unrealized foreign exchange loss of $99.5 million for Q1/2020 due to the weakening of the Canadian dollar relative to the U.S. dollar at March 31, 2020 compared to December 31, 2019. This compares to an unrealized foreign exchange gain of $26.9 million in Q1/2019 due to the strengthening of the Canadian dollar relative to the U.S. dollar over Q1/2019.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S. dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange loss of $0.4 million for Q1/2020 compared to a gain of $0.6 million for Q1/2019.

Income Taxes

	Three Months Ended March 31		
($ thousands)	**2020**	2019	Change
Current income tax expense	**$ 469**	$ 595	$ (126)
Deferred income tax recovery	**(283,179)**	(14,485)	(268,694)
Total income tax recovery	**$ (282,710)**	$ (13,890)	$ (268,820)

Current income tax expense was $0.5 million for Q1/2020 compared to $0.6 million for Q1/2019.

We recorded a deferred income tax recovery of $283.2 million for Q1/2020 as compared to $14.5 million for Q1/2019. Our deferred income tax recovery was higher in Q1/2020 due to the impairment of assets recorded in the quarter.

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.

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. Pursuant to these regulations, the Company will no longer be entitled to certain tax benefits previously recognized during Q1/2020 and 2019. Accordingly, a non-cash charge against deferred income taxes in the amount of $24.8 million will be recorded in the three months ended June 30, 2020.

Net Income (Loss) and Adjusted Funds Flow

The components of adjusted funds flow and net income or loss for the three months ended March 31, 2020 and 2019 are set forth in the following table.

	Three Months Ended March 31		
($ thousands)	**2020**	2019	Change
Petroleum and natural gas sales	**$ 336,614**	$ 453,424	$ (116,810)
Royalties	**(56,720)**	(81,325)	24,605
Revenue, net of royalties	**279,894**	372,099	(92,205)
Expenses			
Operating	**(104,470)**	(100,292)	(4,178)
Transportation	**(10,342)**	(13,330)	2,988
Blending and other	**(21,357)**	(16,788)	(4,569)
Operating netback	**$ 143,725**	$ 241,689	$ (97,964)
General and administrative	**(9,775)**	(14,136)	4,361
Cash financing and interest	**(28,535)**	(28,184)	(351)
Realized financial derivatives gain	**26,850**	18,814	8,036
Realized foreign exchange (loss) gain	**(371)**	595	(966)
Other income	**2,031**	2,587	(556)
Current income tax expense	**(469)**	(595)	126
Share based compensation	**(521)**	—	(521)
Adjusted funds flow	**$ 132,935**	$ 220,770	$ (87,835)
Exploration and evaluation	**(260)**	(1,844)	1,584
Depletion and depreciation	**(181,386)**	(185,354)	3,968
Share based compensation	**(2,262)**	(5,843)	3,581
Non-cash financing and accretion	**(10,685)**	(4,558)	(6,127)
Unrealized financial derivatives gain (loss)	**95,995**	(53,261)	149,256
Unrealized foreign exchange (loss) gain	**(99,521)**	26,941	(126,462)
Gain on dispositions	**137**	—	137
Impairment	**(2,716,349)**	—	(2,716,349)
Deferred income tax recovery	**283,179**	14,485	268,694
Net income (loss) for the period	**$ (2,498,217)**	$ 11,336	$ (2,509,553)

We generated adjusted funds flow of $132.9 million for Q1/2020, a decrease of $87.8 million from $220.8 million reported in Q1/2019. The decrease in adjusted funds flow is primarily due to the decline in commodity benchmark prices which resulted in a $92.2 million decrease in revenue, net of royalties.

In Q1/2020 we reported a net loss of $2.5 billion compared to net income of $11.3 million in Q1/2019. The increase in net loss was driven by a $2.7 billion impairment expense, a $87.8 million decrease in adjusted funds flow and a $126.5 million increase in unrealized foreign exchange losses. These decreases to net income were partially offset by a $149.3 million increase in unrealized gains on financial derivatives in Q1/2020 and a $268.7 million increase in the deferred tax recovery.

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 gain of $173.9 million for Q1/2020 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the weakening of the Canadian dollar relative to the U.S. dollar at March 31, 2020 compared to December 31, 2019. The CAD/USD exchange rate was 1.4120 CAD/USD as at March 31, 2020 compared to 1.2965 CAD/USD at December 31, 2019.

Capital Expenditures

Capital expenditures for the three months ended March 31, 2020 and 2019 are summarized as follows.

	Three Months Ended March 31					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 99,537**	**$ 53,072**	**$ 152,609**	$ 88,881	$ 46,059	$ 134,940
Facilities	**19,003**	**300**	**19,303**	12,940	2,662	15,602
Land, seismic and other	**4,570**	**295**	**4,865**	3,049	252	3,301
Total exploration and development	**$ 123,110**	**$ 53,667**	**$ 176,777**	$ 104,870	$ 48,973	$ 153,843
Total acquisitions, net of proceeds from divestitures	**$ (40)**	**$ —**	**$ (40)**	$ —	$ —	$ —

Exploration and development expenditures were $176.8 million for Q1/2020 compared to $153.8 million for Q1/2019. Expenditures in Q1/2020 were lower than we previously indicated as we suspended our operated capital activity in mid-March as a result of the sharp decline in crude oil prices. Higher exploration and development expenditures in Q1/2020 relative to Q1/2019 reflects additional activity on our light and heavy oil properties in Canada and the timing of drilling and completion activity on our Eagle Ford properties in the U.S.

In Canada, we invested $123.1 million on exploration and development activities in Q1/2020 which is $18.2 million higher than $104.9 million in Q1/2019. Exploration and development expenditures of $123.1 million for Q1/2020 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 $19.0 million on facilities. Exploration and development expenditures of $104.9 million for Q1/2019 included costs associated with 98 (78.3 net) light oil wells, 1 (1.0 net) heavy oil wells and 4 (4.0 net) stratigraphic exploration wells. Facility expenditures for Q1/2020 were higher than Q1/2019 due to the additional costs associated with our polymer flood operations at Lloydminster. Total exploration and development costs for Q1/2020 were $18.2 million higher than Q1/2019 due to the additional activity on our Viking light oil properties and heavy oil properties at Lloydminster.

Total U.S. exploration and development expenditures were $53.7 million for Q1/2020 which is higher than $49.0 million for Q1/2019. During Q1/2020 we participated in the drilling of 17 (3.8 net) wells and commenced production from 30 (6.1 net) wells compared to 23 (3.6 net) wells drilled and 36 (8.9 net) wells on production during Q1/2019. Exploration and development expenditures were higher in Q1/2020 relative to Q1/2019 due to the timing of drilling and completion activity on our lands along with a slight increase in the CAD/USD exchange rate used to translate amounts from U.S. dollars. The majority of the completion costs for wells to be brought on production in Q2/2020 have been incurred in Q1/2020.

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.

CAPITAL RESOURCES AND LIQUIDITY

We took action to improve our capital structure and financial liquidity during Q1/2020. 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 along with the early redemption of the $300 million principal amount of 6.625% senior unsecured notes due July 19, 2022. We also negotiated an extension of 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 $417.0 million of undrawn capacity on our credit facilities at March 31, 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 March 31, 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 have 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 remain focused on driving further efficiencies in our operations and have identified approximately $130 million of cost reductions for operating, transportation and G&A expenses in 2020. This includes reducing salaries for all full time employees and all annual retainers paid to our directors by 10% effective April 1, 2020.

We are expecting compliance with the financial covenants applicable to our credit facilities for at least the next twelve months. 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 ensure 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 sustain our operations and 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 March 31, 2020, net debt of $2,051.6 million was $179.8 million higher than $1,871.8 million at December 31, 2019. The increase in net debt is primarily the result of a $110.7 million increase in the reported amount of our U.S. dollar denominated net debt due to a weaker Canadian dollar at March 31, 2020 along with exploration and development expenditures that exceeded adjusted funds flow by $43.8 million. We incurred total costs of $15.8 million including transaction costs on the issuance of the US $500 million senior notes due 2027 and the early redemption expense on redemption of the $300 million senior notes due 2022.

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 March 31, 2020, our net debt to adjusted funds flow ratio was 2.5 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 $179.8 million increase in net debt at March 31, 2020.

Credit Facilities

At March 31, 2020, the principal amount of credit facilities and letters of credit outstanding was $694.9 million and we had $417.0 million of undrawn capacity under our credit facilities that total approximately $1.11 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 exceeds 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 3.4% for Q1/2020 compared to 4.2% for Q1/2019.

Financial Covenants

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at March 31, 2020.

Covenant Description	Position as at March 31, 2020	Covenant
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.8:1.00**	3.50:1.00
Interest Coverage(3) (Minimum Ratio)	**8.6:1.00**	2.00:1.00

(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 March 31, 2020, the Company's Senior Secured Debt totaled $694.9 million which includes $678.7 million of principal amounts outstanding and $16.2 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 March 31, 2020 was $923.8 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 March 31, 2020 were $107.2 million.

Long-Term Notes

We have two series of long-term notes outstanding that total $1.27 billion as at March 31, 2020. The long-term notes do not contain any significant 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 8.1:1.00 as at March 31, 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"). 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 three months ended March 31, 2020, we issued 2.2 million common shares pursuant to our share-based compensation program. As at May 7, 2020, we had 560.5 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 March 31, 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	**$ 209,776**	$ 209,776	$ —	$ —	$ —
Credit facilities[(1) (2)]	**678,740**	—	—	678,740	—
Long-term notes[(2)]	**1,270,800**	—	—	564,800	706,000
Interest on long-term notes[(3)]	**565,153**	93,545	187,090	160,630	123,888
Lease agreements	**13,342**	6,269	6,683	390	—
Processing agreements	**12,114**	6,583	1,454	670	3,407
Transportation agreements	**116,237**	13,022	43,027	35,486	24,702
Total	**$ 2,866,162**	$ 329,195	$ 238,254	$ 1,440,716	$ 857,997

(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.

Physical Delivery Commitments

We have commitments to deliver heavy oil volumes by rail. These contracts are held for the purpose of delivery of non-financial items in accordance with our expected sale requirements. Physical delivery contracts are not considered financial instruments and, as a result, no asset or liability has been recognized in the consolidated statements of financial position.

As at March 31, 2020, we had committed to deliver the following volumes of raw bitumen to market on rail. Pricing for these contracts is based on either the WTI benchmark or the WCS benchmark, less a discount.

Period	**Volume (bbl/d)**
April 2020	6,500
May 2020	3,250
June 2020	6,000
July 2020 - December 2020	11,500

QUARTERLY FINANCIAL INFORMATION

	2020	2019				2018		
($ thousands, except per common share amounts)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Petroleum and natural gas sales	**336,614**	445,895	424,600	482,000	453,424	358,437	436,761	347,605
Net income (loss)	**(2,498,217)**	(117,772)	15,151	78,826	11,336	(231,238)	27,412	(58,761)
Per common share - basic	**(4.46)**	(0.21)	0.03	0.14	0.02	(0.42)	0.07	(0.25)
Per common share - diluted	**(4.46)**	(0.21)	0.03	0.14	0.02	(0.42)	0.07	(0.25)
Adjusted funds flow	**132,935**	232,147	213,379	236,130	220,770	110,828	171,210	106,690
Per common share - basic	**0.24**	0.42	0.38	0.42	0.40	0.20	0.46	0.45
Per common share - diluted	**0.24**	0.42	0.38	0.42	0.40	0.20	0.45	0.45
Exploration and development	**176,777**	153,117	139,085	106,246	153,843	184,162	139,195	78,830
Canada	**123,110**	104,460	96,774	68,259	104,870	125,507	94,477	30,608
U.S.	**53,667**	48,657	42,311	37,987	48,973	58,655	44,718	48,222
Acquisitions, net of divestitures	**(40)**	563	(30)	1,647	—	229	—	(21)
Net debt	**2,051,617**	1,871,791	1,971,339	2,028,686	2,175,241	2,265,167	2,112,090	1,784,835
Total assets	**3,441,040**	5,914,083	6,233,875	6,222,190	6,359,157	6,377,198	6,491,303	4,476,906
Common shares outstanding	**560,483**	558,305	557,972	556,798	555,872	554,060	553,950	236,662
Daily production								
Total production (boe/d)	**98,452**	96,360	94,927	98,402	101,115	98,890	82,412	70,664
Canada (boe/d)	**62,262**	57,794	58,134	58,580	60,018	60,453	45,214	34,042
U.S. (boe/d)	**36,190**	38,566	36,793	39,822	41,097	38,437	37,198	36,622
Benchmark prices								
WTI oil (US$/bbl)	**46.17**	56.96	56.45	59.81	54.90	58.81	69.50	67.88
WCS heavy (US$/bbl)	**25.65**	41.13	44.21	49.14	42.61	19.39	47.25	48.61
CAD/USD avg exchange rate	**1.3445**	1.3201	1.3207	1.3376	1.3293	1.3215	1.3070	1.2911
AECO gas ($/mcf)	**2.14**	2.34	1.04	1.17	1.94	1.94	1.35	1.03
NYMEX gas (US$/mmbtu)	**1.95**	2.50	2.23	2.64	3.15	3.64	2.90	2.80
Sales price ($/boe)	**35.19**	48.25	47.14	51.49	47.98	37.89	55.03	51.22
Royalties ($/boe)	**(6.33)**	(8.72)	(8.59)	(9.67)	(8.94)	(8.77)	(12.13)	(12.01)
Operating expense ($/boe)	**(11.66)**	(11.23)	(11.15)	(11.22)	(11.02)	(10.76)	(10.25)	(10.91)
Transportation expense ($/boe)	**(1.15)**	(1.00)	(1.13)	(1.33)	(1.46)	(1.21)	(1.26)	(1.22)
Operating netback ($/boe)	**16.05**	27.30	26.27	29.27	26.56	17.15	31.39	27.08
Financial derivatives gain (loss) ($/boe)	**3.00**	2.59	2.39	1.45	2.07	(0.34)	(4.07)	(4.57)
Operating netback after financial derivatives ($/boe)	**19.05**	29.89	28.66	30.72	28.63	16.81	27.32	22.51

Strong operating results for Q1/2020 were overshadowed by the emergence of COVID-19 and the impact the global health crisis has had on the outlook for future crude oil demand. We delivered production of 98,452 boe/d for Q1/2020 which reflects our successful exploration and development programs in the U.S. and Canada, and marks our sixth quarter of solid operational results following the strategic combination with Raging River Exploration Inc. on August 22, 2018.

Commodity prices were relatively strong as Q1/2020 began 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$30.45/bbl in March. The impact of this sharp decline is reflected in our realized sales price of $35.19/boe for Q1/2020.

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 $132.9 million in Q1/2020 reflects the impact of lower commodity prices which resulted in lower revenue net of royalties.

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 increased from $1,784.8 million at Q2/2018 to $2,051.6 million at Q1/2020 primarily due to the assumption of $363.6 million of net debt associated with the strategic combination with Raging River Exploration Inc. during Q3/2018. This increase in net debt was partially offset by free cash flow generated throughout 2019 which was directed towards debt repayment.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at March 31, 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 three months ended March 31, 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.

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 March 31	
($ thousands)	**2020**	2019
Cash flow from operating activities	**$ 182,567**	$ 157,365
Change in non-cash working capital	**(53,873)**	58,477
Asset retirement obligations settled	**4,241**	4,928
Adjusted funds flow	**$ 132,935**	$ 220,770

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 March 31	
($ thousands)	**2020**	2019
Cash flow used in investing activities	**$ 161,022**	$ 187,588
Change in non-cash working capital	**16,327**	(33,680)
Proceeds from dispositions	**40**	—
Additions to other plant and equipment	**(612)**	(65)
Exploration and development expenditures	**$ 176,777**	$ 153,843

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 follow table provides our computation of free cash flow.

	Three Months Ended March 31	
($ thousands)	**2020**	2019
Adjusted funds flow	**$ 132,935**	$ 220,770
Exploration and development expenditures	**(176,777)**	(153,843)
Payments on lease obligations	**(1,516)**	(1,389)
Asset retirement obligations settled	**(4,241)**	(4,928)
Free cash flow	**$ (49,599)**	$ 60,610

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)	**March 31, 2020**	December 31, 2019
Credit facilities(1)	**$ 678,740**	$ 506,471
Long-term notes(1)	**1,270,800**	1,337,200
Trade and other payables	**209,776**	207,454
Cash	**—**	(5,572)
Trade and other receivables	**(107,699)**	(173,762)
Net debt	**$ 2,051,617**	$ 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 March 31	
($ thousands)	**2020**	2019
Petroleum and natural gas sales	**$ 336,614**	$ 453,424
Blending and other expense	**(21,357)**	(16,788)
Total sales, net of blending and other expense	**315,257**	436,636
Royalties	**(56,720)**	(81,325)
Operating expense	**(104,470)**	(100,292)
Transportation expense	**(10,342)**	(13,330)
Operating netback	**143,725**	241,689
Realized financial derivative gain	**26,850**	18,814
Operating netback after realized financial derivatives	**$ 170,575**	$ 260,503

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 March 31	
($ thousands)	**2020**	2019
Net income (loss)	**$ (2,498,217)**	$ 11,336
Plus:		
Financing and interest	**39,220**	32,742
Unrealized foreign exchange (gain) loss	**99,521**	(26,941)
Unrealized financial derivatives (gain) loss	**(95,995)**	53,261
Current income tax expense	**469**	595
Deferred income tax recovery	**(283,179)**	(14,485)
Depletion and depreciation	**181,386**	185,354
Gain on dispositions	**(137)**	—
Impairment	**2,716,349**	—
Non-cash items[1]	**2,522**	7,687
Bank EBITDA	**$ 161,939**	$ 249,549

(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 March 31, 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; our ability to shut-in and quickly restart production; that sustained low commodity prices may result in non-compliance with our financial covenants and reduced liquidity; that we will pro-actively negotiate amendments to our existing credit facilities; 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; the existence, operation and strategy of our risk management program; that management of our debt levels is a priority; the non-cash charge against deferred income tax we intend to take in Q2/2020; 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 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 March 31, 2020	As at December 31, 2019
ASSETS			
Current assets			
Cash		**$ —**	$ 5,572
Trade and other receivables		**107,699**	173,762
Financial derivatives	17	**96,652**	5,433
		204,351	184,767
Non-current assets			
Exploration and evaluation assets	5	**203,999**	320,210
Oil and gas properties	6	**2,974,796**	5,387,889
Other plant and equipment		**7,725**	7,598
Lease assets		**12,511**	13,619
Deferred income tax asset	14	**37,658**	—
		$ 3,441,040	$ 5,914,083
LIABILITIES			
Current liabilities			
Trade and other payables		**$ 209,776**	$ 207,454
Financial derivatives	17	**3,892**	8,668
Lease obligations		**5,882**	5,798
Asset retirement obligations	9	**10,978**	11,579
		230,528	233,499
Non-current liabilities			
Credit facilities	7	**676,055**	505,412
Long-term notes	8	**1,252,156**	1,328,175
Lease obligations		**6,859**	8,085
Asset retirement obligations	9	**650,249**	656,395
Deferred income tax liability		**—**	235,308
		2,815,847	2,966,874
SHAREHOLDERS' EQUITY			
Shareholders' capital	10	**5,726,465**	5,718,835
Contributed surplus		**12,344**	17,712
Accumulated other comprehensive income		**730,163**	556,224
Deficit		**(5,843,779)**	(3,345,562)
		625,193	2,947,209
		$ 3,441,040	$ 5,914,083

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended March 31	
	Notes	**2020**	2019
Revenue, net of royalties			
Petroleum and natural gas sales	13	**$ 336,614**	$ 453,424
Royalties		**(56,720)**	(81,325)
		279,894	372,099
Expenses			
Operating		**104,470**	100,292
Transportation		**10,342**	13,330
Blending and other		**21,357**	16,788
General and administrative		**9,775**	14,136
Exploration and evaluation	5	**260**	1,844
Depletion and depreciation		**181,386**	185,354
Impairment	5, 6	**2,716,349**	—
Share-based compensation	11	**2,783**	5,843
Financing and interest	15	**39,220**	32,742
Financial derivatives (gain) loss	17	**(122,845)**	34,447
Foreign exchange loss (gain)	16	**99,892**	(27,536)
Gain on dispositions		**(137)**	—
Other income		**(2,031)**	(2,587)
		3,060,821	374,653
Net loss before income taxes		**(2,780,927)**	(2,554)
Income tax expense (recovery)	14		
Current income tax expense		**469**	595
Deferred income tax recovery		**(283,179)**	(14,485)
		(282,710)	(13,890)
Net income (loss)		**$ (2,498,217)**	$ 11,336
Other comprehensive income (loss)			
Foreign currency translation adjustment		**173,939**	(47,794)
Comprehensive loss		**$ (2,324,278)**	$ (36,458)
Net income (loss) per common share	12		
Basic		**$ (4.46)**	$ 0.02
Diluted		**$ (4.46)**	$ 0.02
Weighted average common shares (000's)	12		
Basic		**559,804**	555,438
Diluted		**559,804**	558,732

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		7,646	(7,646)	—	—	**—**
Share-based compensation		—	5,843	—	—	**5,843**
Comprehensive income (loss)		—	—	(47,794)	11,336	**(36,458)**
Balance at March 31, 2019		$ 5,709,162	$ 17,334	$ 620,080	$ (3,321,767)	**$ 3,024,809**
Balance at December 31, 2019		$ 5,718,835	$ 17,712	$ 556,224	$ (3,345,562)	**$ 2,947,209**
Vesting of share awards	10	7,630	(7,630)	—	—	**—**
Share-based compensation	11	—	2,262	—	—	**2,262**
Comprehensive income (loss)		—	—	173,939	(2,498,217)	**(2,324,278)**
Balance at March 31, 2020		$ 5,726,465	$ 12,344	$ 730,163	$ (5,843,779)	**$ 625,193**

See accompanying notes to the condensed consolidated interim financial statements.

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

		Three Months Ended March 31	
	Notes	**2020**	2019
CASH PROVIDED BY (USED IN):			
Operating activities			
Net income (loss) for the period		**$ (2,498,217)**	$ 11,336
Adjustments for:			
Share-based compensation	11	**2,262**	5,843
Unrealized foreign exchange loss (gain)	16	**99,521**	(26,941)
Exploration and evaluation	5	**260**	1,844
Depletion and depreciation		**181,386**	185,354
Impairment	5, 6	**2,716,349**	—
Non-cash financing, accretion, and early redemption expense	15	**10,685**	4,558
Unrealized financial derivatives (gain) loss	17	**(95,995)**	53,261
Gain on dispositions		**(137)**	—
Deferred income tax recovery		**(283,179)**	(14,485)
Asset retirement obligations settled	9	**(4,241)**	(4,928)
Change in non-cash working capital		**53,873**	(58,477)
		182,567	157,365
Financing activities			
Increase in credit facilities		**155,921**	31,612
Payments on lease obligations		**(1,516)**	(1,389)
Net proceeds from issuance of long-term notes	8	**652,150**	—
Redemption of long-term notes	8	**(833,672)**	—
		(27,117)	30,223
Investing activities			
Additions to exploration and evaluation assets	5	**(3,788)**	(1,125)
Additions to oil and gas properties	6	**(172,989)**	(152,718)
Additions to other plant and equipment		**(612)**	(65)
Proceeds from dispositions		**40**	—
Change in non-cash working capital		**16,327**	(33,680)
		(161,022)	(187,588)
Change in cash		**(5,572)**	—
Cash, beginning of period		**5,572**	—
Cash, end of period		**$ —**	$ —
Supplementary information			
Interest paid		**$ 22,597**	$ 22,035
Income taxes paid		**$ —**	$ —

See accompanying notes to the condensed consolidated interim financial statements.

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is an oil and gas corporation engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and 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 May 7, 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 of the global economy. The North American oil and gas industry has been particularly impacted as restrictions attempting to limit the spread of COVID-19 in conjunction with additional supply from the OPEC+ price war have resulted in a sharp decline in demand for crude oil and has resulted in unprecedented volatility in global crude oil prices. There is significant ongoing uncertainty regarding the extent and duration of the COVID-19 pandemic and the impact it will have on demand and prices for the commodities we produce, on our suppliers, on our employees, and on the global economy.

These factors have impacted our results for the three months ended 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 these and possibly other 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 are expecting compliance with the financial covenants applicable to our credit facilities for at least the next twelve months. 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 ensure their availability. There is no certainty that we will be successful in negotiating such amendments.

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 March 31	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 194,844**	$ 264,039	**$ 141,770**	$ 189,385	**$ —**	$ —	**$ 336,614**	$ 453,424
Royalties	**(15,518)**	(25,184)	**(41,202)**	(56,141)	**—**	—	**(56,720)**	(81,325)
	179,326	238,855	**100,568**	133,244	**—**	—	**279,894**	372,099
Expenses								
Operating	**78,922**	74,102	**25,548**	26,190	**—**	—	**104,470**	100,292
Transportation	**10,342**	13,330	**—**	—	**—**	—	**10,342**	13,330
Blending and other	**21,357**	16,788	**—**	—	**—**	—	**21,357**	16,788
General and administrative	**—**	—	**—**	—	**9,775**	14,136	**9,775**	14,136
Exploration and evaluation	**260**	1,844	**—**	—	**—**	—	**260**	1,844
Depletion and depreciation	**122,748**	115,020	**56,670**	69,824	**1,968**	510	**181,386**	185,354
Impairment	**1,855,000**	—	**861,349**	—	**—**	—	**2,716,349**	—
Share-based compensation	**—**	—	**—**	—	**2,783**	5,843	**2,783**	5,843
Financing and interest	**—**	—	**—**	—	**39,220**	32,742	**39,220**	32,742
Financial derivatives (gain) loss	**—**	—	**—**	—	**(122,845)**	34,447	**(122,845)**	34,447
Foreign exchange loss (gain)	**—**	—	**—**	—	**99,892**	(27,536)	**99,892**	(27,536)
Gain on dispositions	**(137)**	—	**—**	—	**—**	—	**(137)**	—
Other income	**—**	—	**—**	—	**(2,031)**	(2,587)	**(2,031)**	(2,587)
	2,088,492	221,084	**943,567**	96,014	**28,762**	57,555	**3,060,821**	374,653
Net income (loss) before income taxes	**(1,909,166)**	17,771	**(842,999)**	37,230	**(28,762)**	(57,555)	**(2,780,927)**	(2,554)
Income tax expense (recovery)								
Current income tax expense	**469**	—	**—**	595	**—**	—	**469**	595
Deferred income tax (recovery) expense	**(91,697)**	4,248	**(185,996)**	2,694	**(5,486)**	(21,427)	**(283,179)**	(14,485)
	(91,228)	4,248	**(185,996)**	3,289	**(5,486)**	(21,427)	**(282,710)**	(13,890)
Net income (loss)	**$(1,817,938)**	$ 13,523	**$ (657,003)**	$ 33,941	**$ (23,276)**	$ (36,128)	**$(2,498,217)**	$ 11,336
Total oil and natural gas capital expenditures[1]	**$ 123,070**	$ 104,870	**$ 53,667**	$ 48,973	**$ —**	$ —	**$ 176,737**	$ 153,843

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

		March 31, 2020		December 31, 2019
Canadian assets	$	1,579,174	$	3,484,123
U.S. assets		1,744,978		2,403,310
Corporate assets		116,888		26,650
Total consolidated assets	$	3,441,040	$	5,914,083

5. EXPLORATION AND EVALUATION ASSETS

		March 31, 2020		December 31, 2019
Balance, beginning of period	$	320,210	$	358,935
Capital expenditures		3,788		2,948
Property acquisitions		—		1,523
Divestitures		—		(443)
Property swaps		479		417
Impairment		(127,861)		(7,822)
Exploration and evaluation expense		(260)		(11,764)
Transfer to oil and gas properties (note 6)		(3,642)		(16,204)
Foreign currency translation		11,285		(7,380)
Balance, end of period	$	203,999	$	320,210

At March 31, 2020, the Company identified indicators of impairment for the exploration and evaluation assets within all 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) $**	**5,387,889**
Capital expenditures		172,989	—	172,989
Transfers from exploration and evaluation assets (note 5)		3,642	—	3,642
Change in asset retirement obligations (note 9)		(7,599)	—	(7,599)
Property swaps		(1,190)	178	(1,012)
Impairment		—	(2,588,488)	(2,588,488)
Foreign currency translation		355,138	(168,345)	186,793
Depletion		—	(179,418)	(179,418)
Balance, March 31, 2020	**$**	**11,651,277 $**	**(8,676,481) $**	**2,974,796**

The Company recorded an impairment of $2.6 billion for its oil and gas properties at March 31, 2020 and $180.0 million at December 31, 2019.

At March 31, 2020, the Company identified indicators of impairment for all of its 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 identified for the remaining CGUs as at December 31, 2019.

7. CREDIT FACILITIES

		March 31, 2020		December 31, 2019
Credit facilities - U.S. dollar denominated[(1)]	**$**	**375,093**	$	206,144
Credit facilities - Canadian dollar denominated		**303,647**		300,327
Credit facilities - principal		**678,740**		506,471
Unamortized debt issuance costs		**(2,685)**		(1,059)
Credit facilities	**$**	**676,055**	$	505,412

(1) U.S. dollar denominated credit facilities balance was US$265.7 million as at March 31, 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 March 31, 2020, Baytex had $16.2 million of outstanding letters of credit (December 31, 2019 - $15.2 million) under the Credit Facilities.

At March 31, 2020, Baytex was in compliance with all of the covenants contained in the Credit Facilities. We are expecting compliance with the financial covenants applicable to our credit facilities for at least the next twelve months. 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 ensure 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 March 31, 2020.

Covenant Description	Position as at March 31, 2020	Covenant
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	**0.8:1.00**	**3.50:1.00**
Interest Coverage[3] (Minimum Ratio)	**8.6:1.00**	**2.00:1.00**

(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 March 31, 2020, the Company's Senior Secured Debt totaled $694.9 million which includes $678.7 million of principal amounts outstanding and $16.2 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 March 31, 2020 was $923.8 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 March 31, 2020 was $107.2 million.

8. LONG-TERM NOTES

	March 31, 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	**564,800**	518,600
8.75% notes (US$500,000 – principal) due April 1, 2027	**706,000**	—
Total long-term notes - principal[1]	**1,270,800**	1,337,200
Unamortized debt issuance costs	**(18,644)**	(9,025)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,252,156**	$ 1,328,175

(1) The decrease in the principal amount of long-term notes outstanding from December 31, 2019 to March 31, 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 $99.2 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 March 31, 2020, the fixed charge coverage ratio was 8.1:1.00.

9. ASSET RETIREMENT OBLIGATIONS

		March 31, 2020		December 31, 2019
Balance, beginning of period	**$**	**667,974**	$	646,898
Liabilities incurred		**8,591**		21,748
Liabilities settled		**(4,241)**		(15,417)
Liabilities acquired from property acquisitions		**—**		1,648
Liabilities divested		**(116)**		(1,331)
Property swaps		**(514)**		792
Accretion (note 15)		**2,931**		13,713
Change in estimate		**(1,399)**		19,632
Changes in discount rates and inflation rates(1)		**(14,791)**		(17,486)
Foreign currency translation		**2,792**		(2,223)
Balance, end of period	**$**	**661,227**	$	667,974
Less current portion of asset retirement obligations		**10,978**		11,579
Non-current portion of asset retirement obligations	**$**	**650,249**	$	656,395

(1) The discount and inflation rates at March 31, 2020 were 1.3% and 0.9%, 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 March 31, 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	2,178		7,630
Balance, March 31, 2020	**560,483**	**$**	**5,726,465**

11. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to the share awards of $2.8 million for the three months ended March 31, 2020 ($5.8 million for the three months ended March 31, 2019) which includes $0.5 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 three months ended March 31, 2020 ($2.65 per restricted and performance award for the three months ended March 31, 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	(1,343)	(835)	(2,178)
Forfeited	(87)	(150)	(237)
Balance, March 31, 2020	**4,610**	**5,403**	**10,013**

(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 $3.0 million on March 31, 2020.

During the three months ended March 31, 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	(652)	7.19
Balance, March 31, 2020	**1,823**	**$ 6.70**

Exercise price	Options Outstanding: Number outstanding at March 31, 2020 (000s)	Weighted average remaining life (years)	Weighted average exercise price	Options Exercisable: Number exercisable at March 31, 2020 (000s)	Weighted average exercise price
$5.00 - $7.00	1,483	0.53	$ 6.43	1,294	$ 6.53
$7.01 - $9.00	340	0.01	7.91	340	7.91
Total	**1,823**	**0.43**	**$ 6.70**	**1,634**	**$ 6.82**

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 March 31					
	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	**$ (2,498,217)**	**559,804**	**$ (4.46)**	$ 11,336	555,438	$ 0.02
Dilutive effect of share awards	**—**	**—**	**—**	—	3,294	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net income (loss) - diluted	**$ (2,498,217)**	**559,804**	**$ (4.46)**	$ 11,336	558,732	$ 0.02

For the three months ended March 31, 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 months ended March 31, 2019, no share awards were considered to be anti-dilutive and 4.5 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 March 31					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 109,084**	**$ 121,155**	**$ 230,239**	$ 132,368	$ 148,916	$ 281,284
Heavy oil	**75,843**	**—**	**75,843**	117,686	—	117,686
NGL	**1,348**	**8,842**	**10,190**	3,441	20,802	24,243
Natural gas sales	**8,569**	**11,773**	**20,342**	10,544	19,667	30,211
Total petroleum and natural gas sales	**$ 194,844**	**$ 141,770**	**$ 336,614**	$ 264,039	$ 189,385	$ 453,424

Included in accounts receivable at March 31, 2020 is $68.2 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:

	Three Months Ended March 31	
	2020	2019
Net loss before income taxes	**$ (2,780,927)**	$ (2,554)
Expected income taxes at the statutory rate of 25.89% (2019 – 27.00%)	**(719,982)**	(690)
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	**585**	1,578
Non-taxable portion of foreign exchange loss (gain)	**12,846**	(3,674)
Effect of change in income tax rates	**20,930**	—
Effect of rate adjustments for foreign jurisdictions	**31,484**	(7,321)
Effect of change in deferred tax benefit not recognized	**370,542**	(3,674)
Adjustments and assessments	**885**	(109)
Income tax recovery	**$ (282,710)**	$ (13,890)

For the three months ended March 31, 2020, the deferred tax recovery includes $20.9 million attributable to decreases in the Alberta provincial income tax rate for the periods from July 1, 2019 to January 1, 2022, which reduced the provincial rate to 11% effective July 1, 2019, and further reduced it by 1% on January 1, 2020. Additional reductions are scheduled for January 2021 and 2022, after which the provincial rate will be 8%.

At March 31, 2020, a deferred tax asset of $37.7 million has been recognized while $398 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 will no longer be entitled to certain tax benefits previously recognized during 2019 and the three months ended March 31, 2020. Accordingly, a charge against deferred income taxes in the amount of $24.8 million will be recorded in the three months ended June 30, 2020.

15. FINANCING AND INTEREST

	Three Months Ended March 31	
	2020	2019
Interest on credit facilities	**$ 4,135**	$ 5,412
Interest on long-term notes	**24,273**	22,602
Interest on lease obligations	**127**	170
Non-cash financing	**4,442**	1,095
Accretion on asset retirement obligations (note 9)	**2,931**	3,463
Early redemption expense (note 8)	**3,312**	—
Financing and interest	**$ 39,220**	$ 32,742

16. FOREIGN EXCHANGE

	Three Months Ended March 31	
	2020	2019
Unrealized foreign exchange loss (gain)	**$ 99,521**	$ (26,941)
Realized foreign exchange loss (gain)	**371**	(595)
Foreign exchange loss (gain)	**$ 99,892**	$ (27,536)

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:

	March 31, 2020		December 31, 2019		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial derivatives	**$ 96,652**	**$ 96,652**	$ 5,433	$ 5,433	Level 2
Total	**$ 96,652**	**$ 96,652**	$ 5,433	$ 5,433	
Financial assets at amortized cost					
Cash	**$ —**	**$ —**	$ 5,572	$ 5,572	—
Trade and other receivables	**107,699**	**107,699**	173,762	173,762	—
Total	**$ 107,699**	**$ 107,699**	$ 179,334	$ 179,334	
Financial Liabilities					
FVTPL					
Financial derivatives	**$ (3,892)**	**$ (3,892)**	$ (8,668)	$ (8,668)	Level 2
Total	**$ (3,892)**	**$ (3,892)**	$ (8,668)	$ (8,668)	
Financial liabilities at amortized cost					
Trade and other payables	**$ (209,776)**	**$ (209,776)**	$ (207,454)	$ (207,454)	—
Credit facilities	**(676,055)**	**(678,740)**	(505,412)	(506,471)	—
Long-term notes	**(1,252,156)**	**(508,214)**	(1,328,175)	(1,290,817)	Level 1
Total	**$ (2,137,987)**	**$ (1,396,730)**	$ (2,041,041)	$ (2,004,742)	

There were no transfers between Level 1 and Level 2 during the three months ended March 31, 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	
	March 31, 2020	December 31, 2019	**March 31, 2020**	December 31, 2019
U.S. dollar denominated	**US$80,731**	US$8,733	**US$1,074,265**	US$841,961

From time to time the Company exercises its right to draw U.S. dollar denominated borrowings on its Credit Facilities in order to secure lower borrowing costs depending on the prevailing LIBOR or CDOR rates at inception of the borrowing. Short-term foreign currency contracts are used to convert the U.S. dollar proceeds from LIBOR loans to Canadian dollars and fix the conversion to U.S. dollars at maturity of the borrowing. On March 27, 2020, the Company entered a foreign currency contract to convert US$156 million of proceeds from a U.S. dollar denominated loan to Canadian dollars at a rate of $1.45 CAD/USD and fix the conversion at maturity on April 27, 2020 at a rate of $1.45 CAD/USD. Unrealized gains and losses on the foreign currency contracts are included in unrealized foreign exchange gain or loss for the period and the fair value of the contract is included in the principal amount of the U.S. dollar credit facilities at period end.

Interest Rate Risk

Interest Rate Swaps

As of March 31, 2020, Baytex had an interest rate swap 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 March 31, 2020, the fair value of the interest rate swap was a liability of $0.7 million (December 31, 2019 - nil).

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of May 7, 2020:

	Remaining Period	Volume	Price/Unit[1]	Index
Oil				
Basis Swap	Apr 2020 to Dec 2020	6,500 bbl/d	WTI less US$16.27/bbl	WCS
Basis Swap[7]	Jan 2021 to Dec 2021	2,000 bbl/d	WTI less US$14.12/bbl	WCS
Basis Swap	Apr 2020 to Dec 2020	5,000 bbl/d	WTI less US$6.15/bbl	MSW
MSW Stream[6][7]	June 2020	800 bbl/d	$22.68/bbl	Blended
MSW Stream[6][7]	July 2020	11,695 bbl/d	$27.17/bbl	Blended
Fixed - Sell	Apr 2020 to Dec 2020	2,000 bbl/d	US$58.00/bbl	WTI
Fixed - Sell[7]	Apr 2020 to June 2020	6,000 bbl/d	US$25.62/bbl	WTI
Fixed - Sell[7]	May 2020	6,000 bbl/d	$40.72/bbl	WTI-CAD
Fixed - Sell[7]	June 2020	3,000 bbl/d	US$22.55/bbl	WTI
Fixed - Sell[7]	June 2020	6,000 bbl/d	$32.45/bbl	WTI-CAD
Fixed - Sell[7]	July 2020	4,000 bbl/d	US$24.73/bbl	WTI
Fixed - Sell[7]	July 2020	5,000 bbl/d	$34.05/bbl	WTI-CAD
3-way option[2]	Apr 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$56.00/US$61.35	WTI
3-way option[2]	Apr 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$57.00/US$60.00	WTI
3-way option[2]	Apr 2020 to Dec 2020	4,500 bbl/d	US$50.00/US$57.00/US$62.00	WTI
3-way option[2]	Apr 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$58.00/US$62.00	WTI
3-way option[2]	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.50	WTI
3-way option[2]	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$58.00/US$60.83	WTI
3-way option[2]	Apr 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI
3-way option[2]	Apr 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI
3-way option[2]	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI
3-way option[2]	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI
3-way option[2]	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI
3-way option[2]	Apr 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI
3-way option[2]	Apr 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	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
Natural Gas				
Fixed - Sell	Apr 2020 to Dec 2020	5,000 GJ/d	$1.77/GJ	AECO 7A
Fixed - Sell[7]	May 2020 to Dec 2020	5,500 GJ/d	$2.22/GJ	AECO 7A
Fixed - Sell	Jan 2021 to Dec 2021	10,500 GJ/d	$2.31/GJ	AECO 7A
Fixed - Sell[7]	May 2020 to Dec 2020	2,500 GJ/d	$2.29/GJ	AECO 5A
Fixed - Sell[7]	Oct 2020 to Dec 2020	5,500 mmbtu/d	US$2.64/mmbtu	NYMEX
Fixed - Sell[7]	Jan 2021 to Dec 2021	9,000 mmbtu/d	US$2.72/mmbtu	NYMEX
3-way option[2]	Apr 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 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.
(7) Contracts entered subsequent to March 31, 2020.

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

	Three Months Ended March 31	
	2020	2019
Realized financial derivatives gain	**$ (26,850)**	$ (18,814)
Unrealized financial derivatives (gain) loss	**(95,995)**	53,261
Financial derivatives (gain) loss	**$ (122,845)**	$ 34,447

Physical Delivery Contracts

Baytex has commitments to deliver heavy oil volumes by rail and commitments to deliver natural gas volumes for processing. These contracts are held for the purpose of delivery of non-financial items in accordance with Baytex's expected sale requirements. Physical delivery contracts are not considered financial instruments and, as a result, no asset or liability has been recognized in the condensed consolidated statements of financial position.

As at March 31, 2020, Baytex had committed to deliver the following volumes of raw bitumen to market on rail. Pricing for these contracts is based on either the WTI benchmark or the WCS benchmark, less a discount.

Period	**Volume (bbl/d)**
April 2020	6,500
May 2020	3,250
June 2020	6,000
July 2020 - December 2020	11,500

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 March 31, 2020, Baytex had availability of $417.0 million on its Credit Facilities (December 31, 2019 - $523.8 million). Non-compliance with the financial covenants applicable to the credit facilities could result in the Company's debt becoming due and payable on demand. If the current price environment persists, Baytex will pro-actively approach its lending syndicate to negotiate amendments to ensure the availability of the Company's existing credit facilities. There is no certainty that Baytex will be successful in negotiating such amendments.

The timing of cash outflows relating to financial liabilities as at March 31, 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	**$ 209,776**	$ 209,776	$ —	$ —	$ —
Credit facilities[(1)(2)]	**678,740**	—	—	678,740	—
Long-term notes[(2)]	**1,270,800**	—	—	564,800	706,000
Interest on long-term notes[(3)]	**565,153**	93,545	187,090	160,630	123,888
Lease obligations	**13,342**	6,269	6,683	390	—
	$ 2,737,811	**$ 309,590**	**$ 193,773**	**$ 1,404,560**	**$ 829,888**

(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 6, 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 March 31, 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 March 31, 2020 relates to accrued revenues and receivables related to 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 March 31, 2020 is $68.2 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 March 31, 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 March 31, 2020, trade and other receivables that Baytex has deemed past due (more than 90 days) but not impaired was $2.9 million (December 31, 2019 - $2.7 million). Baytex has estimated the lifetime expected credit loss as at and for the quarter ended March 31, 2020 to be nominal.

The Company's trade and other receivables, net of the allowance for doubtful accounts, were aged as follows as at March 31, 2020.

	March 31, 2020	December 31, 2019
Current (less than 30 days)	**$ 102,276**	$ 169,500
31-60 days	**2,428**	1,199
61-90 days	**121**	342
Past due (more than 90 days)	**2,874**	2,721
	$ 107,699	$ 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

HEAD OFFICE

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BANKERS

Bank of Nova Scotia
ATB Financial
Bank of Montreal
Barclays Bank plc
Canadian Imperial Bank of Commerce
Caisse Centrale Desjardins
Export Development Canada
National Bank of Canada
Royal Bank of Canada
The Toronto-Dominion Bank
Wells Fargo Bank

OFFICERS

Edward D. LaFehr
President and Chief Executive Officer

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