BAYTEX
ENERGY CORP.

Q3 REPORT / 2019

CALGARY, ALBERTA (November 1, 2019) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three and nine months ended September 30, 2019 (all amounts are in Canadian dollars unless otherwise noted).

Strong operating performance has continued across our asset base during the third quarter. We continue to drive cost and capital efficiencies, stable production and substantial free cash flow. Given our year-to-date results, we expect to exceed our 2019 full-year annual production guidance of 97,000 boe/d with exploration and development capital expenditures of approximately $560 million. 2019 exit production is forecast at 95,000-97,000 boe/d.

Our commitment remains to generate free cash flow and improve our balance sheet. We delivered free cash flow (adjusted funds flow less exploration and development capital expenditures) of $74 million in Q3/2019 and $271 million through the first nine months of 2019. This strong free cash flow has contributed to a 13% reduction in our net debt this year.

Q3/2019 Highlights

- Generated production of 94,927 boe/d (82% oil and NGL) in Q3/2019 and 98,125 boe/d (82% oil and NGL) for the first nine months of 2019.
- Delivered adjusted funds flow of $213 million ($0.38 per basic share) in Q3/2019 and $670 million ($1.20 per basic share) for the first nine months of 2019.
- Redeemed US$150 million principal amount of 6.75% senior unsecured notes at par on September 13, 2019.
- Reduced net debt by $57 million during the quarter ($294 million year-to-date) as adjusted funds flow exceeded capital expenditures and the Canadian dollar strengthened relative to the U.S. dollar.
- Realized an operating netback (inclusive of hedging) of $28.66/boe.
- Eagle Ford production averaged 36,793 boe/d in Q3/2019 and 39,221 boe/d for the first nine months of 2019. We established average 30-day initial production rates of approximately 2,100 boe/d per well from 20 (4.6 net) wells that commenced production during the quarter, which represents an approximate 20% improvement over wells brought on-stream in 2018.
- Production in Canada averaged 58,134 boe/d in Q3/2019 and 58,904 boe/d for the first nine months of 2019. We successfully executed our third quarter development program in Canada with 102 (92.5 net) oil wells drilled.
- Using the forward strip for the remainder of 2019[1], we are forecasting adjusted funds flow for 2019 of approximately $875 million. Based on planned capital expenditures, we expect to generate approximately $300 million of free cash flow in 2019.

  (1) 2019 full-year pricing assumptions: WTI - US$56/bbl; LLS - US$62/bbl; WCS differential - US$12/bbl; MSW differential – US$5/bbl, NYMEX Gas - US$2.60/mcf; AECO Gas - $1.54/mcf and Exchange Rate (CAD/USD) - 1.33.

- Published our fourth biennial corporate sustainability report, demonstrating our commitment to transparency and accountability, and our progress in managing the environmental and social impacts of our business. We established a greenhouse gas emissions reduction target with an objective of reducing our corporate emission intensity by 30% by 2021, relative to our 2018 baseline.

	Three Months Ended			Nine Months Ended	
	September 30, 2019	June 30, 2019	September 30, 2018	**September 30, 2019**	September 30, 2018
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 424,600**	$ 482,000	$ 436,761	**$ 1,360,024**	$ 1,070,433
Adjusted funds flow (1)	**213,379**	236,130	171,210	**670,279**	362,155
Per share - basic	**0.38**	0.42	0.46	**1.20**	1.28
Per share - diluted	**0.38**	0.42	0.45	**1.20**	1.28
Net income (loss)	**15,151**	78,826	27,412	**105,313**	(94,071)
Per share - basic	**0.03**	0.14	0.07	**0.19**	(0.33)
Per share - diluted	**0.03**	0.14	0.07	**0.19**	(0.33)
Capital Expenditures					
Exploration and development expenditures (1)	**$ 139,085**	$ 106,246	$ 139,195	**$ 399,174**	$ 311,559
Acquisitions, net of divestitures	**(30)**	1,647	—	**1,617**	(2,047)
Total oil and natural gas capital expenditures	**$ 139,055**	$ 107,893	$ 139,195	**$ 400,791**	$ 309,512
Net Debt					
Bank loan (2)	**$ 570,792**	$ 414,691	$ 490,565	**$ 570,792**	$ 490,565
Long-term notes (2)	**1,359,480**	1,543,645	1,527,733	**1,359,480**	1,527,733
Long-term debt	**1,930,272**	1,958,336	2,018,298	**1,930,272**	2,018,298
Working capital deficiency	**41,067**	70,350	93,792	**41,067**	93,792
Net debt (1)	**$ 1,971,339**	$ 2,028,686	$ 2,112,090	**$ 1,971,339**	$ 2,112,090
Shares Outstanding - basic (thousands)					
Weighted average	**557,888**	556,599	375,435	**556,651**	283,302
End of period	**557,972**	556,798	553,950	**557,972**	553,950
BENCHMARK PRICES					
Crude oil					
WTI (US$/bbl)	**$ 56.45**	$ 59.81	$ 69.50	**$ 57.06**	$ 66.75
LLS (US$/bbl)	**61.88**	67.15	75.25	**63.54**	71.24
LLS differential to WTI (US$/bbl)	**5.43**	7.34	5.75	**6.48**	4.49
Edmonton par ($/bbl)	**68.41**	73.84	81.92	**69.59**	78.19
Edmonton par differential to WTI (US$/bbl)	**(4.66)**	(4.61)	(6.82)	**(4.70)**	(6.03)
WCS heavy oil ($/bbl)	**58.39**	65.73	61.76	**60.24**	57.71
WCS differential to WTI (US$/bbl)	**(12.24)**	(10.68)	(22.25)	**(11.74)**	(21.93)
Natural gas					
NYMEX (US$/mmbtu)	**$ 2.23**	$ 2.64	$ 2.90	**$ 2.67**	$ 2.90
AECO ($/mcf)	**1.04**	1.17	1.35	**1.39**	1.41
CAD/USD average exchange rate	**1.3207**	1.3376	1.3070	**1.3292**	1.2877

	Three Months Ended			Nine Months Ended	
	September 30, 2019	June 30, 2019	September 30, 2018	**September 30, 2019**	September 30, 2018
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**42,829**	42,585	29,731	**43,479**	23,965
Heavy oil (bbl/d)	**25,712**	27,320	27,036	**26,637**	25,824
NGL (bbl/d)	**9,543**	10,986	10,076	**10,745**	9,549
Total liquids (bbl/d)	**78,084**	80,891	66,843	**80,861**	59,338
Natural gas (mcf/d)	**101,054**	105,065	93,414	**103,587**	89,449
Oil equivalent (boe/d @ 6:1) (3)	**94,927**	98,402	82,412	**98,125**	74,246
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense (4)	**$ 411,650**	$ 461,110	$ 417,213	**$ 1,309,396**	$ 1,015,356
Royalties	**(75,017)**	(86,617)	(91,945)	**(242,959)**	(233,989)
Operating expense	**(97,377)**	(100,474)	(77,698)	**(298,143)**	(213,735)
Transportation expense	**(9,903)**	(11,869)	(9,520)	**(35,102)**	(25,875)
Operating netback (1)	**$ 229,353**	$ 262,150	$ 238,050	**$ 733,192**	$ 541,757
General and administrative	**(9,934)**	(11,506)	(10,158)	**(35,576)**	(31,729)
Cash financing and interest	**(26,752)**	(28,092)	(26,343)	**(83,028)**	(76,384)
Realized financial derivatives gain (loss)	**20,857**	12,993	(30,854)	**52,664**	(70,103)
Other (5)	**(145)**	585	515	**3,027**	(1,386)
Adjusted funds flow (1)	**$ 213,379**	$ 236,130	$ 171,210	**$ 670,279**	$ 362,155
Netback (per boe)					
Total sales, net of blending and other expense (4)	**$ 47.14**	$ 51.49	$ 55.03	**$ 48.88**	$ 50.09
Royalties	**(8.59)**	(9.67)	(12.13)	**(9.07)**	(11.54)
Operating expense	**(11.15)**	(11.22)	(10.25)	**(11.13)**	(10.54)
Transportation expense	**(1.13)**	(1.33)	(1.26)	**(1.31)**	(1.28)
Operating netback (1)	**$ 26.27**	$ 29.27	$ 31.39	**$ 27.37**	$ 26.73
General and administrative	**(1.14)**	(1.28)	(1.34)	**(1.33)**	(1.57)
Cash financing and interest	**(3.06)**	(3.14)	(3.47)	**(3.10)**	(3.77)
Realized financial derivatives gain (loss)	**2.39**	1.45	(4.07)	**1.97**	(3.46)
Other (5)	**(0.03)**	0.07	0.07	**0.11**	(0.06)
Adjusted funds flow (1)	**$ 24.43**	$ 26.37	$ 22.58	**$ 25.02**	$ 17.87

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 Q3/2019 MD&A for further information on these amounts.

Operating Results

Strong operating performance continued across our business during the third quarter. We continue to drive cost and capital efficiencies, stable production and substantial free cash flow.

Production during the third quarter averaged 94,927 boe/d (82% oil and NGL), as compared to 98,402 boe/d (82% oil and NGL) in Q2/2019. Our operating results were consistent with our expectations and reflect the timing of our 2019 development program in Canada and the Eagle Ford, and the impact of a third party facility turnaround at Peace River.

Production in the first nine months of 2019 averaged 98,125 boe/d. Given our strong performance year-to-date, we expect to exceed our 2019 full-year annual production guidance of 97,000 boe/d with exploration and development expenditures of approximately $560 million. 2019 exit production is forecast at 95,000-97,000 boe/d.

Exploration and development expenditures totaled $139 million in Q3/2019, bringing aggregate spending in the nine months of 2019 to $399 million. We participated in the drilling of 124 (97.8 net) wells with a 100% success rate during the third quarter.

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 36,793 boe/d (77% liquids) during Q3/2019, as compared to 39,822 boe/d in Q2/2019. The lower volumes during the quarter reflect the timing of completion activity. We commenced production from 20 (4.6 net) wells during the third quarter, as compared to 29 (5.0 net) wells during the second quarter. The wells brought on-stream generated an average 30-day initial production rate of approximately 2,100 boe/d per well, which represents an approximate 20% improvement over wells brought on-stream in 2018.

During Q3/2019, production from the Viking averaged 22,198 boe/d, as compared to 22,565 boe/d in Q2/2019. We maintained an active pace of development during the third quarter with 72.5 net wells drilled and 49.4 net wells brought on production. We currently have three drilling rigs and two frac crews executing our program and expect to drill approximately 245 net wells this year. Inventory enhancement continues to be a priority. We have completed multiple deals and swaps year-to-date adding 220 net unbooked drilling opportunities.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 28,483 boe/d during the third quarter, as compared to 29,983 boe/d in Q2/2019. The lower volumes reflect the timing of our 2019 development program, which is strongly weighted (80%) to the second half of the year and the impact of a third party facility turnaround. During the third quarter, we drilled 20 net heavy oil wells, including four net multi-lateral horizontal wells at Peace River. Heavy oil production is expected to increase to more than 30,000 boe/d during the fourth quarter due to new well completions and the expansion of our Kerrobert thermal project.

East Duvernay Shale Light Oil

We continue to prudently advance the delineation of the East Duvernay Shale, an early stage, high operating netback light oil resource play. To-date, we have drilled seven wells at Pembina, which confirms the prospectivity of our acreage. Two wells brought on-stream in 2019 generated an average 30-day initial production rate of approximately 1,050 boe/d per well (75% liquids) and are in the top 15% of all wells drilled to date in the play. The success of our drilling program in the Pembina area has significantly de-risked our approximately 38 kilometer long acreage fairway, where we hold 275 sections (100% working interest) of Duvernay land.

Financial Review

We delivered adjusted funds flow of $213 million ($0.38 per basic share) in Q3/2019 and $670 million ($1.20 per basic share) through the first nine months of 2019. This resulted in free cash flow (adjusted funds flow less exploration and development capital expenditures) of $74 million in Q3/2019 and $271 million through the first nine months of 2019. This strong free cash flow has contributed to a 13% reduction in our net debt this year including the redemption of our US$150 million senior unsecured notes on September 13, 2019.

We realized an operating netback of $26.27/boe in Q3/2019, as compared to $29.27/boe in Q2/2019 and $31.39/boe in Q3/2018. Including financial derivatives, our operating netback improved to $28.66/boe, as compared to $27.32/boe in Q3/2018.

Our Canadian operations generated an operating netback of $25.43/boe during Q3/2019 while our Eagle Ford asset generated an operating netback of $27.58/boe. During the third quarter, Canadian differentials remained tight, which contributed to strong price realizations.

The following table summarizes our operating netbacks for the periods noted.

	Three Months Ended September 30					
	2019			2018		
($ per boe except for production)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Production (boe/d)	**58,134**	**36,793**	**94,927**	45,214	37,198	82,412
Total sales, net of blending and other [(1)]	**$ 45.96**	**$ 48.99**	**$ 47.14**	$ 47.66	$ 63.98	$ 55.03
Royalties	**(4.90)**	**(14.42)**	**(8.59)**	(6.28)	(19.23)	(12.13)
Operating expense	**(13.78)**	**(6.99)**	**(11.15)**	(13.15)	(6.72)	(10.25)
Transportation expense	**(1.85)**	**—**	**(1.13)**	(2.29)	—	(1.26)
Operating netback [(2)]	**$ 25.43**	**$ 27.58**	**$ 26.27**	$ 25.94	$ 38.03	$ 31.39
Realized financial derivatives gain (loss)	**—**	**—**	**2.39**	—	—	(4.07)
Operating netback after financial derivatives	**$ 25.43**	**$ 27.58**	**$ 28.66**	$ 25.94	$ 38.03	$ 27.32

Notes:

(1) 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.

(2) The term "operating netback" does 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.

Financial Liquidity

We are delivering on our commitment to generate meaningful free cash flow and improve our balance sheet. We redeemed US$150 million principal amount of 6.75% senior unsecured notes at par on September 13, 2019 with the redemption funded from free cash flow generated this year. During the third quarter, we reduced net debt by $57 million ($294 million year-to-date) as adjusted funds flow exceeded capital expenditures and the Canadian dollar strengthened relative to the U.S. dollar over this period. Our net debt, which includes our bank loan, long-term notes and working capital, totaled $1.97 billion at September 30, 2019.

We maintain strong financial liquidity with our credit facilities approximately 50% undrawn and our first long-term note maturity not until 2021. Our credit facilities total approximately $1.06 billion, mature April 2021 and are comprised of US$575 million of revolving credit facilities and a $300 million non-revolving term loan. The credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews.

Risk Management

As part of our normal operations, we are exposed to movements in commodity prices. In an effort to manage these exposures, 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 $21 million in Q3/2019 on these contracts.

For the fourth quarter of 2019, we have entered into hedges on approximately 53% of our net crude oil exposure. This includes 44% of our net WTI exposure with 20% fixed at US$62.35/bbl and 24% hedged utilizing a 3-way option structure that provides us with a US$10/bbl premium to WTI when WTI is at or below US$55.64/bbl and allows upside participation to US$73.65/bbl.

For 2020, we have entered into hedges on approximately 33% of our net crude oil exposure, largely utilizing a 3-way option structure that provides us with an US$8/bbl premium to WTI when WTI is at or below US$50.50/bbl and allows upside participation to US$63.59/bbl. In addition to the 3-way option structure, for the first quarter of 2020 we have also entered into WTI-based fixed price swaps for 4,000 bbl/d at US$55.90/bbl.

Crude-by-rail is an integral part of our egress and marketing strategy for our heavy oil production. For Q4/2019, we expect to deliver 11,500 bbl/d (approximately 40%) of our heavy oil volumes to market by rail. For 2020, our crude by rail volumes are currently contracted at 7,500 bbl/d.

A complete listing of our financial derivative contracts can be found in Note 18 to our Q3/2019 financial statements.

2019 Guidance

Given our strong year-to-date operating performance, we now expect to exceed our 2019 full-year annual production guidance of 97,000 boe/d. 2019 exit production is forecast at 95,000-97,000 boe/d. We remain focused on driving cost and capital efficiencies in our business and anticipate exploration and development expenditures for 2019 of approximately $560 million.

Based on the forward strip for the balance of 2019[(1)], we are forecasting adjusted funds flow of approximately $875 million and expect to generate approximately $300 million of free cash flow, which supports our de-leveraging strategy. Adjusted funds flow in excess of exploration and development expenditures, leasing expenditures and asset retirement obligations, will be used to reduce our indebtedness.

(1) 2019 full-year pricing assumptions: WTI - US$56/bbl; LLS - US$62/bbl; WCS differential - US$12/bbl; MSW differential – US$5/bbl, NYMEX Gas - US$2.60/mcf; AECO Gas - $1.54/mcf and Exchange Rate (CAD/USD) - 1.33.

As we continue to drive debt levels down, we will be positioned to enhance shareholder returns through a combination of organic growth, disciplined capital allocation, share buybacks and/or reinstatement of a dividend.

The following table summarizes our 2019 annual guidance and compares it to our 2019 year-to-date actual results.

	Previous Guidance [(1)]	Current Guidance	YTD 2019
Exploration and development capital ($ millions)	$550 - $600	~ $560	$399.2
Production (boe/d)	96,000 - 97,000	~ 97,000	98,125
Expenses:			
Royalty rate (%)	19 %	No change	19 %
Operating ($/boe)	$10.75 - $11.25	No change	$11.13
Transportation ($/boe)	$1.25 - $1.35	No change	$1.31
General and administrative ($ millions)	$46 ($1.30/boe)	No change	$35.6 ($1.33/boe)
Interest ($ millions)	$112 ($3.23/boe)	No change	$83.0 ($3.10/boe)
Leasing expenditures ($ millions)	$5	No change	4.4
Asset retirement obligations ($ millions)	$17	No change	10.9

(1) As announced on August 1, 2019.

We are in the process of setting our 2020 capital budget, the details of which are expected to be released in December following approval by our Board of Directors.

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

Baytex will host a conference call today, November 1, 2019, 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/baytexq320191101.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 and nine months ended September 30, 2019 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 2019 production, exit production and capital expenditure guidance; that we are committed to generate free cash flow and improve our balance sheet; our forecast for 2019 adjusted funds flow and free cash flow; our GHG emissions intensity reduction target; in the Viking: that we expect to drill 245 wells in 2019 and inventory enhancement is a priority; that heavy oil production will increase to 30,000 boe/d in Q4/2019; in the East Duvernay shale: that we continue to prudently advance the delineation of the asset and that we have de-risked our 38 kilometer acreage fairway; our ability to partially reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts for commodity prices, foreign exchange rates and interest rates; the percentage of our net crude oil and natural gas exposure that is hedged for 2019 and 2020 and the amount and percentage of heavy oil production we expect to delivery by crude by rail and the percentage of crude by rail deliveries that do not have WCS exposure; that we expect to exceed our 2019 full-year production guidance; our planned uses for adjusted funds flow in 2019; our forecast year end 2019 net debt to adjusted funds flow ratio; that we will be positioned to enhance shareholder returns through organic growth, capital allocation, the reinstatement of a dividend and/or share buybacks; guidance for 2019 capital spending and production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligation expenditures; and that we expect to release our 2020 budget in December 2019. In addition, information and statements relating to reserves and contingent resources are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax 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; 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, 2018, 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

Adjusted funds flow is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our cash flow on a continuing basis. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three and nine months ended September 30, 2019.

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as adjusted funds flow less sustaining capital. Sustaining capital is an estimate of the amount of exploration and development expenditures required to offset production declines on an annual basis and maintain flat production volumes.

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. 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 trade and other accounts receivable, trade and other accounts payable, and the principal amount of both the long-term notes and the bank loan. 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

This press release discloses the acquisition of 220 net unbooked drilling opportunities in our Viking asset. The additional drilling opportunities are unbooked locations and are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production.

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.

Baytex Energy Corp.

Baytex Energy Corp. is an oil and gas corporation based in Calgary, Alberta. The company is engaged in the acquisition, development and production of crude oil and natural gas in the Western Canadian Sedimentary Basin and in the Eagle Ford in the United States. Approximately 83% of Baytex’s production is weighted toward crude oil and natural gas liquids. Baytex’s common shares trade on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE.

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

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BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the three and nine months ended September 30, 2019 and 2018
Dated October 31, 2019

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three and nine months ended September 30, 2019. This information is provided as of October 31, 2019. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three and nine months ended September 30, 2019 ("Q3/2019" and "YTD 2019") have been compared with the results for the three and nine months ended September 30, 2018 ("Q3/2018" and "YTD 2018"). This MD&A should be read in conjunction with the Company's condensed consolidated interim financial statements ("consolidated financial statements") for the three and nine months ended September 30, 2019, its audited comparative consolidated financial statements for the years ended December 31, 2018 and 2017, together with the accompanying notes, and its Annual Information Form for the year ended December 31, 2018. 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 has oil and gas operations 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.

On August 22, 2018, Baytex and Raging River Exploration Inc. ("Raging River") completed the strategic combination of the two companies (the "Strategic Combination") by way of a plan of arrangement whereby Baytex acquired all of the issued and outstanding common shares of Raging River. The Strategic Combination increased our light oil exposure and operational control of our properties while improving our leverage ratios. Production from Raging River's properties is approximately 90% light oil from the Viking and Duvernay. The addition of the primarily operated assets to our portfolio increased our inventory of drilling prospects and enhanced our ability to effectively allocate capital.

THIRD QUARTER HIGHLIGHTS

Baytex delivered solid operating and financial results for Q3/2019. We reported adjusted funds flow of $213.4 million which exceeded exploration and development expenditures of $139.1 million for Q3/2019. Production of 94,927 boe/d was in line with expectations after strong operational performance during the first half of 2019 and a reduction in exploration and development activity in Q2/2019 and Q3/2019. We completed the early redemption of our US$150 million 6.75% senior unsecured notes on September 13, 2019 using the liquidity generated by adjusted funds flow of $670.3 million which exceeded exploration and development expenditures of $399.2 million for YTD 2019.

In Canada, production was 58,134 boe/d for Q3/2019 and 58,904 boe/d for YTD 2019 which was 29% and 57% higher than the comparative periods of 2018 which reflects the impact of the Strategic Combination. Exploration and development expenditures of $96.8 million in Q3/2019 were primarily focused on our Viking light oil property along with additional heavy oil development at Peace River and Lloydminster. Exploration and development expenditures included costs associated with drilling 82 (72.5 net) light oil wells in the Viking and 20 (20.0 net) heavy oil wells during Q3/2019.

In the U.S., we continue to observe strong performance from wells brought on stream during Q3/2019 which resulted in production of 36,793 boe/d compared to 37,198 boe/d for Q3/2018. Production for Q3/2019 was in line with expectations after strong operational performance during the first half of 2019 and the timing of completion activity during YTD 2019 resulted in production of 39,822 boe/d in Q2/2019. We invested $42.3 million on exploration and development activity during Q3/2019 and drilled 22 (5.3 net) wells and commenced production from 20 (4.6 net) wells.

We continue to benefit from a narrowing Canadian light and heavy oil differentials after production curtailments mandated by the Government of Alberta came into effect in January 2019. The Edmonton par light oil benchmark averaged $68.41/bbl in Q3/2019 which represents a differential of US$4.66/bbl to the West Texas Intermediate ("WTI") benchmark price as compared to a US$26.51 differential in Q4/2018 and a US$6.82/bbl differential in Q3/2018. The Western Canadian Select ("WCS") heavy oil differential averaged US$12.24/bbl in Q3/2019 relative to a differential of US$39.42/bbl in Q4/2018 and US$22.25/bbl in Q3/2018. Stronger Canadian oil differentials helped to mitigate the impact of a lower WTI benchmark price of US$56.45/bbl for Q3/2019 compared to US$69.50/bbl during Q3/2018.

Adjusted funds flow of $213.4 million in Q3/2019 was $42.2 million higher than $171.2 million for Q3/2018 due to higher production from the Strategic Combination along with $20.9 million of realized hedging gains that more than offset the $8.7 million decrease in operating netback due to lower benchmark pricing.

In Q3/2019 we reported net income of $15.2 million compared to $27.4 million in Q3/2018. The $42.2 million increase in adjusted funds flow in Q3/2019 compared to Q3/2018 was offset by a $35.9 million increase in depletion and depreciation expense in Q3/2019 along with an unrealized foreign exchange loss that exceeded gains by $34.4 million relative to Q3/2018.

We redeemed our US$150 million 6.75% senior unsecured notes on September 13, 2019 using adjusted funds flow generated during YTD 2019. At September 30, 2019, net debt was $1,971.3 million, a $293.9 million decrease from $2,265.2 million at December 31, 2018. Net debt has decreased as adjusted funds flow has exceeded exploration and development expenditures for YTD 2019 by $271.1 million and the Canadian dollar strengthened at September 30, 2019 which reduced the reported amount of our US denominated long-term notes by $32.2 million.

2019 GUIDANCE

The following table compares our 2019 annual guidance to our YTD 2019 results. As a result of our strong operational performance in YTD 2019 we now expect to exceed our 2019 annual production guidance of approximately 97,000 boe/d with exploration and development expenditures of approximately $560 million.

	Previous Annual Guidance (1)	Revised Annual Guidance	YTD 2019
Exploration and development capital	$550 - 600 million	~ $560 million	$399.2 million
Production (boe/d)	96,000 - 97,000	~ 97,000	98,125
Expenses:			
Royalty rate	~ 19.0%	No change	19.0%
Operating	$10.75 - $11.25/boe	No change	$11.13/boe
Transportation	$1.25 - $1.35/boe	No change	$1.31/boe
General and administrative	~ $46 million ($1.30/boe)	No change	$35.6 million ($1.33/boe)
Cash interest	~ $112 million ($3.23/boe)	No change	$83.0 million ($3.10/boe)

(1) As announced on August 1, 2019.

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 September 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**22,493**	**20,336**	**42,829**	9,894	19,837	29,731
Heavy oil	**25,712**	**—**	**25,712**	27,036	—	27,036
Natural Gas Liquids (NGL)	**1,575**	**7,968**	**9,543**	1,096	8,980	10,076
Total liquids (bbl/d)	**49,780**	**28,304**	**78,084**	38,026	28,817	66,843
Natural gas (mcf/d)	**50,122**	**50,932**	**101,054**	43,127	50,287	93,414
Total production (boe/d)	**58,134**	**36,793**	**94,927**	45,214	37,198	82,412
Production Mix						
Light oil and condensate	**39%**	**55%**	**45%**	22%	53%	36%
Heavy oil	**44%**	**—%**	**27%**	60%	—%	33%
NGL	**3%**	**22%**	**10%**	2%	24%	12%
Natural gas	**14%**	**23%**	**18%**	16%	23%	19%

	Nine Months Ended September 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**22,636**	**20,843**	**43,479**	3,898	20,067	23,965
Heavy oil	**26,637**	**—**	**26,637**	25,824	—	25,824
Natural Gas Liquids (NGL)	**1,430**	**9,315**	**10,745**	1,202	8,347	9,549
Total liquids (bbl/d)	**50,703**	**30,158**	**80,861**	30,924	28,414	59,338
Natural gas (mcf/d)	**49,207**	**54,380**	**103,587**	40,232	49,217	89,449
Total production (boe/d)	**58,904**	**39,221**	**98,125**	37,629	36,617	74,246
Production Mix						
Light oil and condensate	**39%**	**53%**	**44%**	10%	55%	32%
Heavy oil	**45%**	**—%**	**27%**	69%	—%	35%
NGL	**2%**	**24%**	**11%**	3%	23%	13%
Natural gas	**14%**	**23%**	**18%**	18%	22%	20%

After strong operational performance and production of 98,125 boe/d in YTD 2019 we expect to exceed our annual production guidance for 2019 of approximately 97,000 boe/d which represents the top end of our previous range of 96,000 to 97,000 boe/d.

Production averaged 94,927 boe/d for Q3/2019 and 98,125 boe/d for YTD 2019 compared to annual guidance of approximately 97,000 boe/d. Production in 2019 is higher than 2018 due to the Strategic Combination along with production related to our exploration and development program. As expected, our production declined in Q3/2019 following strong operational performance during the first six months of 2019 and a reduction in exploration and development expenditures on our U.S. properties during Q2/2019.

In Canada, production was 58,134 boe/d for Q3/2019 and 58,904 boe/d for YTD 2019 compared to 45,214 boe/d in Q3/2018 and 37,629 boe/d in YTD 2018. The increase in production in 2019 relative to 2018 is primarily due to the production contribution from the Strategic Combination along with strong well performance from our exploration and development program. Production from our Viking and Duvernay properties consists of approximately 90% light oil which resulted in a higher proportion of our Canadian production being comprised of light oil in both periods of 2019 relative to 2018.

Production in the U.S. averaged 36,793 boe/d for Q3/2019 and 39,221 boe/d in YTD 2019 compared to 37,198 boe/d for Q3/2018 and 36,617 boe/d in YTD 2018. U.S. production of 36,793 boe/d for Q3/2019 is slightly lower than 37,198 boe/d for Q3/2018 due to lower completion activity on our lands during Q2/2019 and Q3/2019. We initiated production from 20 (4.6 net) wells during Q3/2019 compared to 26 (4.9 net) wells in Q3/2018. We continue to see strong initial production results from wells brought on stream in 2019 which resulted in production for YTD 2019 that was 2,604 boe/d higher than 36,617 boe/d in YTD 2018 with only a slight increase in completion activity. During YTD 2019 we commenced production from 85 (18.6 net) wells compared to YTD 2018 when 85 (17.9 net) wells were brought on production.

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 declined during Q3/2019 as forecast demand levels were impacted by the ongoing trade dispute between the U.S. and China which more than offset the effect of compliance with OPEC production curtailments along with U.S. imposed sanctions on Iran and Venezuela. North American benchmark prices for Q3/2019 and YTD 2019 were lower than the same periods of 2018 as a result of increasing supply from U.S. production along with uncertainty around global crude oil demand. Canadian oil differentials remained strong in Q3/2019 and YTD 2019 compared to Q3/2018 and YTD 2018 due to the Government of Alberta's production curtailments which came into effect in January of 2019. While our YTD 2019 production levels were not significantly impacted by the Government of Alberta's curtailment program we have benefited from narrower differentials for our light and heavy oil production in Q3/2019 and YTD 2019.

We compare the price received for our U.S. crude oil production to the Louisiana Light Sweet ("LLS") stream at St. James, Louisiana, which is a representative benchmark for light oil pricing at the U.S. Gulf coast. The LLS benchmark averaged US$61.88/bbl during Q3/2019 and US$63.54/bbl during YTD 2019 which is a premium to WTI of US$5.43/bbl in Q3/2019 and US$6.48/bbl in YTD 2019. The LLS benchmark averaged US$75.25/bbl or a premium to WTI of US$5.75/bbl in Q3/2018 and US$71.24/bbl or a premium of US $4.49/bbl in YTD 2018.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $68.41/bbl for Q3/2019 and $69.59/bbl for YTD 2019 compared to $81.92/bbl for Q3/2018 and $78.19/bbl for YTD 2018. Production curtailments mandated by the Government of Alberta have narrowed the Edmonton par differential to WTI in 2019. Edmonton par traded at a US$4.66/bbl discount to WTI in Q3/2019 and a discount of US$4.70/bbl in YTD 2019 compared to a US $6.82/bbl discount in Q3/2018 and a US$6.03/bbl discount in YTD 2018.

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. We continue to benefit from a narrowing of the WCS heavy oil differential due to the Government of Alberta production curtailments which came into effect in January of 2019. The WCS heavy oil differential to WTI averaged US$12.24/bbl in Q3/2019 and US$11.74/bbl in YTD 2019 as compared to US$22.25/bbl for Q3/2018 and US$21.93 for YTD 2018. As a result, the WCS heavy oil benchmark price of $60.24/bbl in YTD 2019 increased $2.53/bbl from $57.71/bbl in YTD 2018 despite a $10.12/bbl decrease in WTI (expressed in Canadian dollars) over the same periods.

Natural Gas

North American natural gas prices for Q3/2019 and YTD 2019 were lower than Q3/2018 and YTD 2018 as significant growth in North American natural gas production outpaced growth in natural gas demand. Canadian natural gas prices remained challenged during Q3/2019 and YTD 2019 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$2.23/mmbtu in Q3/2019 and US$2.67/mmbtu in YTD 2019 which is lower compared to US$2.90/mmbtu in both periods of 2018. Record natural gas production levels in the U.S. have resulted in an oversupplied North American market and lower natural gas prices in 2019 relative to 2018.

In Canada, we receive natural gas pricing based on the AECO benchmark which continues to trade at a significant discount to NYMEX as a result of increasing supply and limited market access for Canadian natural gas production. The AECO benchmark averaged $1.04/mcf during Q3/2019 and $1.39/mcf in YTD 2019 which is lower than $1.35/mcf for Q3/2018 and $1.41/mcf in YTD 2018.

The following tables compare select benchmark prices and our average realized selling prices for the three and nine months ended September 30, 2019 and 2018.

	Three Months Ended September 30			Nine Months Ended September 30		
	2019	2018	Change	**2019**	2018	Change
Benchmark Averages						
WTI oil (US$/bbl)[(1)]	**56.45**	69.50	(13.05)	**57.06**	66.75	(9.69)
LLS oil (US$/bbl)[(2)]	**61.88**	75.25	(13.37)	**63.54**	71.24	(7.70)
LLS oil differential to WTI (US$/bbl)	**5.43**	5.75	(0.32)	**6.48**	4.49	1.99
Edmonton par oil ($/bbl)	**68.41**	81.92	(13.51)	**69.59**	78.19	(8.60)
Edmonton par oil differential to WTI (US$/bbl)	**(4.66)**	(6.82)	2.16	**(4.70)**	(6.03)	1.33
WCS heavy oil ($/bbl)[(3)]	**58.39**	61.76	(3.37)	**60.24**	57.71	2.53
WCS heavy oil differential to WTI (US$/bbl)	**(12.24)**	(22.25)	10.01	**(11.74)**	(21.93)	10.19
AECO natural gas price ($/mcf)[(4)]	**1.04**	1.35	(0.31)	**1.39**	1.41	(0.02)
NYMEX natural gas price (US$/mmbtu)[(5)]	**2.23**	2.90	(0.67)	**2.67**	2.90	(0.23)
CAD/USD average exchange rate	**1.3207**	1.3070	0.0137	**1.3292**	1.2877	0.0415

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) LLS refers to the Argus trade month average for Louisiana Light Sweet oil.
(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 September 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices[(1)]						
Light oil and condensate ($/bbl)	**$ 65.20**	**$ 75.01**	**$ 69.86**	$ 76.42	$ 93.37	$ 87.73
Heavy oil ($/bbl)[(2)]	**44.39**	**—**	**44.39**	48.15	—	48.15
NGL ($/bbl)	**10.26**	**15.07**	**14.27**	41.11	36.93	37.38
Natural gas ($/mcf)	**0.95**	**3.08**	**2.03**	1.21	3.90	2.66
Weighted average ($/boe)[(2)]	**$ 45.96**	**$ 48.99**	**$ 47.14**	$ 47.66	$ 63.98	$ 55.03

	Nine Months Ended September 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices[(1)]						
Light oil and condensate ($/bbl)	**$ 66.20**	**$ 77.81**	**$ 71.77**	$ 75.08	$ 86.90	$ 84.98
Heavy oil ($/bbl)[(2)]	**45.53**	**—**	**45.53**	43.95	—	43.95
NGL ($/bbl)	**17.12**	**18.74**	**18.52**	35.33	31.37	31.87
Natural gas ($/mcf)	**1.49**	**3.51**	**2.55**	1.39	3.80	2.72
Weighted average ($/boe)[(2)]	**$ 47.69**	**$ 50.67**	**$ 48.88**	$ 40.56	$ 59.89	$ 50.09

(1) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in this table excludes the impact of financial derivatives.
(2) 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 $47.14/boe for Q3/2019 and $48.88/boe for YTD 2019 compared to $55.03/boe for Q3/2018 and $50.09/boe in YTD 2018. Our realized price in the U.S. was $48.99/boe in Q3/2019 which is $14.99/boe lower than $63.98/boe in Q3/2018 due to the decrease in U.S. crude oil benchmark prices. In Canada, our realized price of $45.96/boe for Q3/2019 was $1.70/boe lower than $47.66/boe for Q3/2018 as the decline in benchmark prices was partially offset by a higher weighting of light oil in our Canadian production over the same periods.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price was $65.20/bbl in Q3/2019 and $66.20/bbl in YTD 2019 compared to $76.42/bbl in Q3/2018 and $75.08/bbl in YTD 2018. Our realized light oil and condensate price for Q3/2019 and YTD 2019 represents a discount of $3.21/bbl and $3.39/bbl to the Edmonton par price for the same periods. Our Canadian light oil price realizations have improved following the acquisition of our Viking and Duvernay light oil properties in Q3/2018 which receive higher pricing than our legacy light oil properties in Canada which reported a $9.14/bbl discount to the Edmonton par benchmark for the first six months of 2018.

We compare the price received for our U.S. light oil and condensate production to the LLS benchmark. Our realized light oil and condensate price averaged $75.01/bbl for Q3/2019 and $77.81/bbl for YTD 2019 compared to $93.37/bbl for Q3/2018 and $86.90/bbl in YTD 2018. Expressed in U.S. dollars, our realized light oil and condensate price of US$56.80/bbl for Q3/2019 and US$58.54/bbl for YTD 2019. Our realized light oil and condensate pricing reflects a change in certain marketing contracts to be based on the Magellan East Houston ("MEH") benchmark which is representative pricing at the Magellan East crude oil terminal in Houston, Texas. This change in marketing contracts during Q1/2019 resulted in a US$5.08/bbl discount to the LLS benchmark for Q3/2019 and a US $5.00/bbl discount for YTD 2019 relative to a discount of US$3.81/bbl and US$3.76/bbl for the same periods of 2018.

Our realized heavy oil price, net of blending and other expense averaged $44.39/bbl in Q3/2019 and $45.53/bbl for YTD 2019 compared to $48.15/bbl in Q3/2018 and $43.95/bbl in YTD 2018. Our realized heavy oil price for Q3/2019 was $3.76/bbl lower in Q3/2018 which is relatively consistent with the $3.37/bbl decrease in the WCS benchmark over the same period. The increase in our realized heavy oil price for YTD 2019 was $1.58/bbl which is slightly lower than the $2.53/bbl increase in the WCS benchmark compared to YTD 2018. While our realized heavy oil price has improved in 2019 it did not increase as much as the WCS benchmark due to certain WTI based heavy oil marketing contracts that were entered into prior to the Government of Alberta's decision to curtail production which resulted in a narrowing of the WCS differential.

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 $14.27/bbl in Q3/2019 or 19% of WTI (expressed in Canadian dollars) compared to $37.38/bbl or 41% of WTI (expressed in Canadian dollars) in Q3/2018. Our YTD 2019 realized NGL price was $18.52/bbl or 24% of WTI (expressed in Canadian dollars) compared to $31.87/bbl or 37% of WTI (expressed in Canadian dollars) for YTD 2018. The decrease in our realized NGL price for Q3/2019 and YTD 2019 reflects higher production and NGL supply in North America which resulted in lower market prices for propane and butane relative to Q3/2018 and YTD 2018.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price was $0.95/mcf for Q3/2019 and $1.49/mcf for YTD 2019 compared to $1.21/mcf in Q3/2018 and $1.39/mcf in YTD 2018. The change in our realized natural gas prices in both periods of 2019 is relatively consistent with the change in the AECO natural gas price over the same periods of 2018. In the U.S., our realized natural gas price was US$2.33/mcf for Q3/2019 and US$2.64/mcf for YTD 2019 compared to US $2.98/mcf in Q3/2018 and US$2.95/mcf in YTD 2018. Our realized natural gas price in the U.S. is relatively consistent with the NYMEX benchmark in both periods of 2019 and 2018.

Petroleum and Natural Gas Sales

	Three Months Ended September 30					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 134,921**	**$ 140,344**	**$ 275,265**	$ 69,557	$ 170,402	$ 239,959
Heavy oil	**117,961**	**—**	**117,961**	139,305	—	139,305
NGL	**1,486**	**11,045**	**12,531**	4,147	30,508	34,655
Total oil sales	**254,368**	**151,389**	**405,757**	213,009	200,910	413,919
Natural gas sales	**4,401**	**14,442**	**18,843**	4,796	18,046	22,842
Total petroleum and natural gas sales	**258,769**	**165,831**	**424,600**	217,805	218,956	436,761
Blending and other expense	**(12,950)**	**—**	**(12,950)**	(19,548)	—	(19,548)
Total sales, net of blending and other expense	**$ 245,819**	**$ 165,831**	**$ 411,650**	$ 198,257	$ 218,956	$ 417,213

	Nine Months Ended September 30					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 409,117**	**$ 442,763**	**$ 851,880**	$ 79,894	$ 476,086	$ 555,980
Heavy oil	**381,684**	**—**	**381,684**	364,957	—	364,957
NGL	**6,684**	**47,656**	**54,340**	11,595	71,480	83,075
Total oil sales	**797,485**	**490,419**	**1,287,904**	456,446	547,566	1,004,012
Natural gas sales	**20,021**	**52,099**	**72,120**	15,296	51,125	66,421
Total petroleum and natural gas sales	**817,506**	**542,518**	**1,360,024**	471,742	598,691	1,070,433
Blending and other expense	**(50,628)**	**—**	**(50,628)**	(55,077)	—	(55,077)
Total sales, net of blending and other expense	**$ 766,878**	**$ 542,518**	**$ 1,309,396**	$ 416,665	$ 598,691	$ 1,015,356

Total sales, net of blending and other expense, of $411.7 million for Q3/2019 decreased $5.6 million from $417.2 million reported for Q3/2018 while total sales, net of blending and other expense, of $1,309.4 million for YTD 2019 was $294.0 million higher than $1,015.4 million in YTD 2018. Production for Q3/2019 and YTD 2019 was 12,515 boe/d and 23,879 boe/d higher than the same periods of 2018 due to the Strategic Combination along with our exploration and development programs. The increase in total sales from higher production in Q3/2019 and YTD 2019 was offset by lower realized pricing relative to the same periods of 2018.

In Canada, total sales, net of blending and other expense, was $245.8 million for Q3/2019 which is an increase of $47.6 million from Q3/2018. Total petroleum and natural gas sales increased with production due to the Strategic Combination and our exploration and development programs. Production in Canada was 12,920 boe/d higher in Q3/2019 which resulted in a $56.7 million increase in total sales, net of blending and other expense relative to Q3/2018. Our average realized price of $45.96/boe for Q3/2019 was slightly lower than $47.66/boe for Q3/2018 due to the decrease in benchmark pricing for our production in Canada and resulted in a $9.1 million decrease in total sales, net of blending and other expense. Higher production and stronger realized pricing resulted in our total sales, net of blending and other expense, increasing to $766.9 million in YTD 2019 from $416.7 million in YTD 2018.

In the U.S., petroleum and natural gas sales were $165.8 million for Q3/2019 and decreased $53.1 million from $219.0 million reported for Q3/2018. The decrease in total sales was primarily from lower realized pricing for Q3/2019 which decreased $14.99/boe from Q3/2018 and resulted in a $50.7 million decrease in total petroleum and natural gas sales. Lower realized pricing in YTD 2019 resulted in petroleum and natural gas sales of $542.5 million which was $56.2 million lower than $598.7 million for YTD 2018 despite a 2,604 boe/d increase in production over the same period.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three and nine months ended September 30, 2019 and 2018.

	Three Months Ended September 30					
	2019			2018		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 26,193**	**$ 48,824**	**$ 75,017**	$ 26,139	$ 65,806	$ 91,945
Average royalty rate[1]	**10.7%**	**29.4%**	**18.2%**	13.2%	30.1%	22.0%
Royalties per boe	**$ 4.90**	**$ 14.42**	**$ 8.59**	$ 6.28	$ 19.23	$ 12.13

	Nine Months Ended September 30					
	2019			2018		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 82,313**	**$ 160,646**	**$ 242,959**	$ 55,471	$ 178,518	$ 233,989
Average royalty rate[1]	**10.7%**	**29.6%**	**18.6%**	13.3%	29.8%	23.0%
Royalties per boe	**$ 5.12**	**$ 15.00**	**$ 9.07**	$ 5.40	$ 17.86	$ 11.54

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

Total royalties in YTD 2019 were $243.0 million or 18.6% of total sales, net of blending and other expense compared to $234.0 million or 23.0% in YTD 2018. Our average royalty rate was 18.6% for YTD 2019 which is consistent with our annual guidance of approximately 19.0% for 2019.

Royalties for Q3/2019 were $75.0 million and averaged 18.2% of total sales, net of blending and other expense, compared to $91.9 million or 22.0% for Q3/2018. Total royalty expense is lower in Q3/2019 due to the decrease in petroleum and natural gas sales in the U.S. relative to Q3/2018 combined with a decrease in our total royalty rate due to the Strategic Combination. The increase in total sales, net of blending and other expense for YTD 2019 resulted in higher total royalties relative to YTD 2018 which was partially offset by the decrease in our total royalty rate over the same periods.

Our Canadian royalty rate of 10.7% for Q3/2019 and YTD 2019 was lower than 13.2% for Q3/2018 and 13.3% for YTD 2018 due to the lower royalty rate on our Viking light oil properties which were acquired in the Strategic Combination. In the U.S., royalties for Q3/2019 and YTD 2019 averaged 29.4% and 29.6% of total petroleum and natural gas sales which is consistent with the same periods of 2018 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 September 30					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 73,701**	**$ 23,676**	**$ 97,377**	$ 54,710	$ 22,988	$ 77,698
Operating expense per boe	**$ 13.78**	**$ 6.99**	**$ 11.15**	$ 13.15	$ 6.72	$ 10.25

	Nine Months Ended September 30					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 221,680**	**$ 76,463**	**$ 298,143**	$ 147,054	$ 66,681	$ 213,735
Operating expense per boe	**$ 13.79**	**$ 7.14**	**$ 11.13**	$ 14.31	$ 6.67	$ 10.54

Operating expense of $11.15/boe for Q3/2019 and $11.13/boe for YTD 2019 is consistent with expectations and our 2019 annual guidance range of $10.75 - $11.25/boe.

Operating expense was $97.4 million ($11.15/boe) for Q3/2019 and $298.1 million ($11.13/boe) for YTD 2019 compared to $77.7 million ($10.25/boe) in Q3/2018 and $213.7 million ($10.54/boe) in YTD 2018. The increase in total operating expense is from higher production in Q3/2019 and YTD 2019 relative to Q3/2018 and YTD 2018 along with a slight increase in per unit operating expense.

In Canada, operating expense was $73.7 million ($13.78/boe) for Q3/2019 and $221.7 million ($13.79/boe) for YTD 2019 compared to $54.7 million ($13.15/boe) for Q3/2018 and $147.1 million ($14.31/boe) for YTD 2018. Total operating expense in Canada has increased with higher production following the Strategic Combination. Per unit operating costs of $13.78/boe for Q3/2019 and $13.79/boe in YTD 2019 were consistent with $13.15/boe in Q3/2018 and lower than $14.31/boe in YTD 2018 as our Viking and Duvernay properties have lower per unit operating expense relative to our other Canadian properties which resulted in lower per unit operating expense in Canada following the Strategic Combination.

U.S. operating expense was $23.7 million ($6.99/boe) for Q3/2019 and $76.5 million ($7.14/boe) for YTD 2019 compared to $23.0 million ($6.72/boe) for Q3/2018 and $66.7 million ($6.67/boe) for YTD 2018. The increase in total operating expense reflects higher U.S. production combined with a weaker Canadian dollar in Q3/2019 and YTD 2019 compared to Q3/2018 and YTD 2018. Expressed in U.S. dollars, per boe operating expense for our U.S. properties have been fairly consistent and were US$5.29/boe in Q3/2019 and US$5.37/boe in YTD 2019 compared to US$5.14/boe for Q3/2018 and US$5.18/boe in YTD 2018.

Transportation Expense

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of oil in Canada to pipeline and rail terminals which can vary from period to period depending on hauling distances as we seek to optimize sales prices and trucking rates. The following table compares our transportation expense for the three and nine months ended September 30, 2019 and 2018.

	Three Months Ended September 30					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 9,903**	**$ —**	**$ 9,903**	$ 9,520	$ —	$ 9,520
Transportation expense per boe	**$ 1.85**	**$ —**	**$ 1.13**	$ 2.29	$ —	$ 1.26

	Nine Months Ended September 30					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 35,102**	**$ —**	**$ 35,102**	$ 25,875	$ —	$ 25,875
Transportation expense per boe	**$ 2.18**	**$ —**	**$ 1.31**	$ 2.52	$ —	$ 1.28

We reported transportation expense of $1.31/boe for YTD 2019 which is in line with expectations and our guidance range of $1.25 - $1.35/boe for 2019. Transportation expense was $9.9 million ($1.13/boe) for Q3/2019 and $35.1 million ($1.31/boe) for YTD 2019 compared to $9.5 million ($1.26/boe) for Q3/2018 and $25.9 million ($1.28/boe) for YTD 2018. The increase in transportation expense for 2019 reflects additional oil trucking and transportation costs associated with our Viking and Duvernay light oil properties acquired as part of the Strategic Combination.

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 $13.0 million for Q3/2019 and $50.6 million for YTD 2019 which is relatively consistent with $19.5 million for Q3/2018 and $55.1 million for YTD 2018. The decrease in blending and other expense in both periods of 2019 was primarily a result of a decrease in the cost of blending diluent relative to the same periods of 2018.

Financial Derivatives

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our adjusted funds flow. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets for commodities and currencies fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the three and nine months ended September 30, 2019 and 2018.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2019**	2018	Change	**2019**	2018	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ 19,631**	$ (31,704)	$ 51,335	**$ 49,944**	$ (72,529)	$ 122,473
Natural gas	**1,243**	872	371	**2,713**	2,448	265
Interest and financing	**(17)**	(22)	5	**7**	(22)	29
Total	**$ 20,857**	$ (30,854)	$ 51,711	**$ 52,664**	$ (70,103)	$ 122,767
Unrealized financial derivatives gain (loss)						
Crude oil	**$ 8,559**	$ 4	$ 8,555	**$ (29,083)**	$ (63,454)	$ 34,371
Natural gas	**(1,041)**	(1,027)	(14)	**(1,391)**	(2,663)	1,272
Interest and financing	**148**	977	(829)	**(448)**	977	(1,425)
Total	**$ 7,666**	$ (46)	$ 7,712	**$ (30,922)**	$ (65,140)	$ 34,218
Total financial derivatives gain (loss)						
Crude oil	**$ 28,190**	$ (31,700)	$ 59,890	**$ 20,861**	$ (135,983)	$ 156,844
Natural gas	**202**	(155)	357	**1,322**	(215)	1,537
Interest and financing	**131**	955	(824)	**(441)**	955	(1,396)
Total	**$ 28,523**	$ (30,900)	$ 59,423	**$ 21,742**	$ (135,243)	$ 156,985

We recorded total financial derivative gains of $28.5 million for Q3/2019 and $21.7 million for YTD 2019. Realized financial derivatives gains of $20.9 million for Q3/2019 and $52.7 million for YTD 2019 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 $7.7 million for Q3/2019 and unrealized loss of $30.9 million for YTD 2019 is primarily a result of fluctuations in the futures prices for crude oil which impacts the fair value of our contracts in place at September 30, 2019.

Realized gains on crude oil financial derivatives of $19.6 million in Q3/2019 and $49.9 million for YTD 2019 are primarily a result of market prices for Brent and WTI settling at levels below the prices set in our contracts outstanding during the periods. Our natural gas financial derivatives generated gains of $1.2 million in Q3/2019 and $2.7 million for YTD 2019. These gains were primarily a result of the NYMEX index for Q3/2019 and YTD 2019 averaging less than the fixed price on our NYMEX contracts in place for both periods.

We recorded unrealized gains of $7.7 million in Q3/2019 and unrealized losses of $30.9 million in YTD 2019 due to fluctuations in the futures prices for crude oil along with additional notional volumes associated with financial derivative contracts entered for 2020. The fair value of our financial derivative contracts was a net asset of $48.7 million at September 30, 2019 compared to a net asset of $41.0 million at June 30, 2019 and a net asset of $79.6 million at December 31, 2018.

We had the following commodity financial derivative contracts as at October 31, 2019.

	Period	Volume	Price/Unit [(1)]	Index
Oil				
Basis Swap	Oct 2019 to Dec 2019	7,000 bbl/d	WTI less US$17.59/bbl	WCS
Basis Swap	Oct 2019 to Dec 2019	4,000 bbl/d	WTI less US$8.00/bbl	MSW
Basis Swap	Jan 2020 to Dec 2020	2,500 bbl/d	WTI less US$16.10/bbl	WCS
Fixed - Sell	Oct 2019 to Dec 2019	12,000 bbl/d	US$62.35/bbl	WTI
Fixed - Sell	Oct 2019 to Dec 2019	2,000 bbl/d	US$65.50/bbl	Brent
Fixed - Sell [(5)]	Jan 2020 to Mar 2020	4,000 bbl/d	US$55.90/bbl	WTI
3-way option[(2)]	Oct 2019 to Dec 2019	2,000 bbl/d	US$49.00/US$61.70/US$75.00	WTI
3-way option[(2)]	Oct 2019 to Dec 2019	2,000 bbl/d	US$50.00/US$60.00/US$70.00	WTI
3-way option[(2)]	Oct 2019 to Dec 2019	1,000 bbl/d	US$55.00/US$65.00/US$72.60	WTI
3-way option[(2)]	Oct 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$72.50	WTI
3-way option[(2)]	Oct 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$73.00	WTI
3-way option[(2)]	Oct 2019 to Dec 2019	2,000 bbl/d	US$57.00/US$67.00/US$73.00	WTI
3-way option[(2)]	Oct 2019 to Dec 2019	2,000 bbl/d	US$58.00/US$68.00/US$74.00	WTI
3-way option[(2)]	Oct 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$69.90/US$75.00	WTI
3-way option[(2)]	Oct 2019 to Dec 2019	1,000 bbl/d	US$61.00/US$71.00/US$76.00	WTI
3-way option[(2)]	Oct 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$78.00	WTI
3-way option[(2)]	Oct 2019 to Dec 2019	1,000 bbl/d	US$55.50/US$65.50/US$75.50	Brent
3-way option[(2)]	Oct 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$70.00/US$77.55	Brent
3-way option[(2)]	Oct 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$83.00	Brent
3-way option[(2)]	Jan 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$56.00/US$61.35	WTI
3-way option[(2)]	Jan 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$57.00/US$60.00	WTI
3-way option[(2)(5)]	Jan 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$57.00/US$62.00	WTI
3-way option[(2)]	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI
3-way option[(2)]	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI
3-way option[(2)]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI
3-way option[(2)]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI
3-way option[(2)]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI
3-way option[(2)]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI
3-way option[(2)]	Jan 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	WTI
Swaption[(3)]	Jan 2020 to Dec 2020	1,000 bbl/d	US$62.50/bbl	WTI
Swaption[(3)]	Jan 2020 to Dec 2020	1,000 bbl/d	US$63.20/bbl	WTI
Swaption[(4)]	Jan 2021 to Dec 2021	3,000 bbl/d	US$60.75/bbl	WTI
Swaption[(4)(5)]	Jan 2021 to Dec 2021	3,000 bbl/d	US$70.00/bbl	Brent
Natural Gas				
Fixed - Sell	Oct 2019 to Dec 2019	15,000 mmbtu/d	US$2.97	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/US$60/US$70 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50/bbl; Baytex receives US$60.00/bbl when WTI is between US$50/bbl and US$60/bbl; Baytex receives the market price when WTI is between US$60/bbl and US$70/bbl; and Baytex receives US$70/bbl when WTI is above US$70/bbl.
(3) For these contracts, the counterparty has the right, if exercised on December 31, 2019, 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 30, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.
(5) Contracts entered subsequent to September 30, 2019.

Physical Delivery Contracts

The following physical delivery contracts were held for the purpose of delivery of non-financial items in accordance with the Company'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 consolidated statements of financial position.

As at October 31, 2019, Baytex had committed to deliver the following volumes of raw bitumen to market on rail.

Period	Volume
Oct 2019	1,000 bbl/d
Oct 2019 to Dec 2019	11,000 bbl/d
Jan 2020 to Dec 2020	7,500 bbl/d

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the three and nine months ended September 30, 2019 and 2018.

	Three Months Ended September 30					
	2019			2018		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**58,134**	**36,793**	**94,927**	45,214	37,198	82,412
Operating netback:						
Total sales, net of blending and other expense	**$ 45.96**	**$ 48.99**	**$ 47.14**	$ 47.66	$ 63.98	$ 55.03
Less:						
Royalties	**(4.90)**	**(14.42)**	**(8.59)**	(6.28)	(19.23)	(12.13)
Operating expense	**(13.78)**	**(6.99)**	**(11.15)**	(13.15)	(6.72)	(10.25)
Transportation expense	**(1.85)**	**—**	**(1.13)**	(2.29)	—	(1.26)
Operating netback	**$ 25.43**	**$ 27.58**	**$ 26.27**	$ 25.94	$ 38.03	$ 31.39
Realized financial derivatives gain (loss)	**—**	**—**	**2.39**	—	—	(4.07)
Operating netback after financial derivatives	**$ 25.43**	**$ 27.58**	**$ 28.66**	$ 25.94	$ 38.03	$ 27.32

	Nine Months Ended September 30					
	2019			2018		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**58,904**	**39,221**	**98,125**	37,629	36,617	74,246
Operating netback:						
Total sales, net of blending and other expense	**$ 47.69**	**$ 50.67**	**$ 48.88**	$ 40.56	$ 59.89	$ 50.09
Less:						
Royalties	**(5.12)**	**(15.00)**	**(9.07)**	(5.40)	(17.86)	(11.54)
Operating expense	**(13.79)**	**(7.14)**	**(11.13)**	(14.31)	(6.67)	(10.54)
Transportation expense	**(2.18)**	**—**	**(1.31)**	(2.52)	—	(1.28)
Operating netback	**$ 26.60**	**$ 28.53**	**$ 27.37**	$ 18.33	$ 35.36	$ 26.73
Realized financial derivatives gain (loss)	**—**	**—**	**1.97**	—	—	(3.46)
Operating netback after financial derivatives	**$ 26.60**	**$ 28.53**	**$ 29.34**	$ 18.33	$ 35.36	$ 23.27

Our operating netback after financial derivatives was $28.66/boe for Q3/2019 which was $1.34/boe higher than $27.32/boe for Q3/2018. Operating netback after financial derivatives of $29.34/boe for YTD 2019 was $6.07/boe higher than $23.27/boe for the same period of 2018. Operating netback of $26.27/boe in Q3/2019 was lower than $31.39/boe in Q3/2018 due to the decrease in benchmark pricing which resulted in lower per unit sales net of royalties. This was more than offset by the difference on financial derivatives of $6.46/boe in Q3/2019 as we recorded realized gains of $2.39/boe in Q3/2019 compared to realized losses of $4.07/boe in Q3/2018. Our operating netback was $27.37/boe for YTD 2019 compared to YTD 2018 when our operating netback was $26.73/boe as the decrease in our royalty rate more than offset the impact of lower benchmark pricing. We recorded realized gains on financial derivatives of $1.97/boe in YTD 2019 which also contributed to the increase in operating netback after financial derivatives compared YTD 2018 when we recorded realized losses of $3.46/boe.

In Canada, our operating netback was $25.43/boe in Q3/2019 and $26.60/boe in YTD 2019 compared to $25.94/boe in Q3/2018 and $18.33/boe in YTD 2018. Lower benchmark pricing in Q3/2019 resulted in a decrease in our operating netback relative to Q3/2018 despite improved price realizations and a lower royalty rate following the Strategic Combination. The increase in our netback in YTD 2019 was primarily from an increase in our realized sales price per boe as a higher portion of our production was from light oil after the Strategic Combination along with narrower Canadian oil differentials. Our operating netback in the U.S. of $27.58/boe in Q3/2019 and $28.53/boe in YTD 2019 was lower than $38.03/boe in Q3/2018 and $35.36/boe in YTD 2018 as our realized sales price decreased with lower benchmark pricing in both periods of 2019 relative to 2018.

General and Administrative Expense

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

The following table summarizes our G&A expense for the three and nine months ended September 30, 2019 and 2018.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2019**	2018	Change	**2019**	2018	Change
Gross general and administrative expense	**$ 11,633**	$ 13,016	$ (1,383)	**$ 39,907**	$ 38,338	$ 1,569
Overhead recoveries	**(1,699)**	(2,858)	1,159	**(4,331)**	(6,609)	2,278
General and administrative expense	**$ 9,934**	$ 10,158	$ (224)	**$ 35,576**	$ 31,729	$ 3,847
General and administrative expense per boe	**$ 1.14**	$ 1.34	$ (0.20)	**$ 1.33**	$ 1.57	$ (0.24)

We reported G&A expense of $35.6 million ($1.33/boe) for YTD 2019 which is in line with expectations and is consistent with our annual guidance of approximately $46 million ($1.30/boe). We expected G&A expense to decrease during the second half of 2019 as we continue to optimize our business following the Strategic Combination. G&A expense was $9.9 million ($1.14/boe) for Q3/2019 compared to $10.2 million ($1.34/boe) for Q3/2018 which only includes the additional staff and costs associated with the Strategic Combination following closing on August 22, 2018. G&A expense of $35.6 million for YTD 2019 was higher relative to $31.7 million for YTD 2018 due to the additional staff and costs required to integrate the two organizations following the Strategic Combination in Q3/2018. The decrease in G&A expense per boe in Q3/2019 and YTD 2019 relative to the same periods of 2018 reflects the efficiencies we were able to realize by combining the two organizations.

Financing and Interest Expense

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

The following table summarizes our financing and interest expense for the three and nine months ended September 30, 2019 and 2018.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2019**	2018	Change	**2019**	2018	Change
Interest on bank loan	**$ 4,650**	$ 4,108	$ 542	**$ 15,171**	$ 10,297	$ 4,874
Interest on long-term notes	**21,955**	22,235	(280)	**67,382**	66,087	1,295
Interest on lease obligations	**147**	—	147	**475**	—	475
Cash interest	**$ 26,752**	$ 26,343	$ 409	**$ 83,028**	$ 76,384	$ 6,644
Accretion of debt issue costs	**1,607**	866	741	**3,753**	2,991	762
Accretion of asset retirement obligations	**3,407**	2,820	587	**10,268**	7,450	2,818
Financing and interest expense	**$ 31,766**	$ 30,029	$ 1,737	**$ 97,049**	$ 86,825	$ 10,224
Cash interest per boe	**$ 3.06**	$ 3.47	$ (0.41)	**$ 3.10**	$ 3.77	$ (0.67)
Financing and interest expense per boe	**$ 3.64**	$ 3.96	$ (0.32)	**$ 3.62**	$ 4.28	$ (0.66)

Cash interest expense of $83.0 million or $3.10/boe for YTD 2019 was in line with expectations and our 2019 annual guidance of approximately $112 million or $3.23/boe.

Financing and interest expense was $31.8 million in Q3/2019 and $97.0 million for YTD 2019 compared to $30.0 million in Q3/2018 and $86.8 million in YTD 2018. Interest on our bank loan of $4.7 million in Q3/2019 and $15.2 million in YTD 2019 was higher than $4.1 million in Q3/2018 and $10.3 million in YTD 2018 primarily due to the assumption of net debt associated with the Strategic Combination. The weighted average interest rate on our bank loan was 4.3% in YTD 2019 compared to 4.5% in YTD 2018. Interest on our long-term notes was $22.0 million for Q3/2019 and $67.4 million for YTD 2019 compared to $22.2 million for Q3/2018 and $66.1 million for YTD 2018. We redeemed the US$150 million principal amount of 6.75% senior unsecured notes on September 13, 2019 which resulted in slightly lower interest on our long-term notes in Q3/2019 relative to the same period of 2018. The reported amount of interest on our long-term notes was higher in YTD 2019 due to an increase in the exchange rate used to convert the interest on our U.S. dollar denominated long-term notes relative to YTD 2018. Accretion of our asset retirement obligations was higher in Q3/2019 and YTD 2019 as our asset retirement obligation increased with the Strategic Combination.

Exploration and Evaluation Expense

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the derecognition 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 of $2.1 million for Q3/2019 and $8.7 million for YTD 2019 is higher than $0.5 million for Q3/2018 and $3.9 million for YTD 2018 primarily due to a higher amount of acreage expiring in 2019 relative to 2018.

Depletion and Depreciation

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved plus probable reserves volumes and the rate of production for the period. The following table summarizes depletion and depreciation expense for the three and nine months ended September 30, 2019 and 2018.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2019**	2018	Change	**2019**	2018	Change
Depletion	**$ 178,364**	$ 143,913	$ 34,451	**$ 547,345**	$ 362,726	$ 184,619
Depreciation	**2,058**	588	1,470	**4,203**	1,928	2,275
Depletion and depreciation	**$ 180,422**	$ 144,501	$ 35,921	**$ 551,548**	$ 364,654	$ 186,894
Depletion and depreciation per boe	**$ 20.66**	$ 19.06	$ 1.60	**$ 20.59**	$ 17.99	$ 2.60

Depletion and depreciation expense was $180.4 million ($20.66/boe) for Q3/2019 and $551.5 million ($20.59/boe) for YTD 2019 compared to $144.5 million ($19.06/boe) for Q3/2018 and $364.7 million ($17.99/boe) for YTD 2018. Total depletion and depreciation expense was higher in both periods of 2019 due to the Strategic Combination which resulted in a higher depletable base and production relative to the comparative periods of 2018. The depletion rate per boe increased following the Strategic Combination due to the addition of proved plus probable reserves at a higher cost than our historic base.

Share-Based Compensation Expense

Share-based compensation ("SBC") expense associated with the Share Award Incentive Plan is recognized in net income or loss over the vesting period of the share awards with a corresponding increase in contributed surplus. The issuance of common shares upon the conversion of share awards is recorded as an increase in shareholders' capital with a corresponding reduction in contributed surplus. SBC expense varies with the quantity of unvested share awards outstanding and the grant date fair value assigned to the share awards.

We recorded SBC expense of $3.4 million for Q3/2019 and $14.2 million for YTD 2019 compared to $7.2 million for Q3/2018 and $15.0 million for YTD 2018. SBC expense is lower in both periods of 2019 due to the lower total value of awards granted in YTD 2019 compared to YTD 2018 which included additional SBC expense in Q3/2018 associated with the Strategic Combination.

Foreign Exchange

Unrealized foreign exchange gains and losses represent the change in value of the long-term notes and bank loan denominated in U.S. dollars. The long-term notes and bank loan 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.

($ thousands except for exchange rates)	Three Months Ended September 30			Nine Months Ended September 30		
	2019	2018	Change	**2019**	2018	Change
Unrealized foreign exchange loss (gain)	**$ 13,855**	$ (20,583)	$ 34,438	**$ (38,404)**	$ 38,136	$ (76,540)
Realized foreign exchange loss (gain)	**382**	(360)	742	**426**	1,887	(1,461)
Foreign exchange loss (gain)	**$ 14,237**	$ (20,943)	$ 35,180	**$ (37,978)**	$ 40,023	$ (78,001)
CAD/USD exchange rates:						
At beginning of period	**1.3091**	1.3142		**1.3646**	1.2518	
At end of period	**1.3244**	1.2924		**1.3244**	1.2924	

We recorded an unrealized foreign exchange loss of $13.9 million for Q3/2019 due to the weakening of the Canadian dollar relative to the U.S. dollar at September 30, 2019 compared to June 30, 2019. This compares to an unrealized foreign exchange gain of $20.6 million in Q3/2018 due to the strengthening of the Canadian dollar relative to the U.S. dollar over Q3/2018.

We recorded an unrealized foreign exchange gain of $38.4 million for YTD 2019 due to the strengthening of the Canadian dollar relative to the U.S. dollar at September 30, 2019 compared to December 31, 2018. This compares to an unrealized foreign exchange loss of $38.1 million for YTD 2018 due to the weakening of the Canadian dollar relative to the U.S. dollar at September 30, 2018 compared to December 31, 2017.

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 Q3/2019 and YTD 2019 compared to a gain of $0.4 million for Q3/2018 and a loss of $1.9 million for YTD 2018.

Income Taxes

($ thousands)	Three Months Ended September 30			Nine Months Ended September 30		
	2019	2018	Change	**2019**	2018	Change
Current income tax expense (recovery)	**$ 501**	$ —	$ 501	**$ 1,591**	$ (71)	$ 1,662
Deferred income tax expense (recovery)	**1,082**	(4,427)	5,509	**(14,958)**	(51,905)	36,947
Total income tax expense (recovery)	**$ 1,583**	$ (4,427)	$ 6,010	**$ (13,367)**	$ (51,976)	$ 38,609

Current income tax expense was $0.5 million for Q3/2019 and $1.6 million for YTD 2019 compared to the nominal amounts recorded for Q3/2018 and YTD 2018. The current income tax expense for Q3/2019 and YTD 2019 reflects state taxes owing on our U.S. operations.

We recorded deferred income tax expense of $1.1 million for Q3/2019 and a recovery of $15.0 million for YTD 2019 as compared to a recovery of $4.4 million for Q3/2018 and $51.9 million for YTD 2018. Our deferred income tax recovery for YTD 2019 was lower due to higher adjusted funds flow relative to YTD 2018. The deferred income tax recovery for YTD 2019 includes a $10.6 million recovery associated with the Alberta tax rate reduction.

As disclosed in the 2018 annual financial statements, Baytex received several reassessments from the Canada Revenue Agency (the "CRA") in June 2016 which denied $591 million of non-capital loss deductions that Baytex had previously claimed. 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 our file in July 2018. Baytex remains confident that its original tax filings are correct and intends to defend those tax filings through the appeals process.

Net Income (Loss) and Adjusted Funds Flow

The components of adjusted funds flow and net income or loss for the three and nine months ended September 30, 2019 and 2018 are set forth in the following table.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2019**	2018	Change	**2019**	2018	Change
Petroleum and natural gas sales	**$ 424,600**	$ 436,761	$ (12,161)	**$ 1,360,024**	$ 1,070,433	$ 289,591
Royalties	**(75,017)**	(91,945)	16,928	**(242,959)**	(233,989)	(8,970)
Revenue, net of royalties	**349,583**	344,816	4,767	**1,117,065**	836,444	280,621
Expenses						
Operating	**(97,377)**	(77,698)	(19,679)	**(298,143)**	(213,735)	(84,408)
Transportation	**(9,903)**	(9,520)	(383)	**(35,102)**	(25,875)	(9,227)
Blending and other	**(12,950)**	(19,548)	6,598	**(50,628)**	(55,077)	4,449
Operating netback	**$ 229,353**	$ 238,050	$ (8,697)	**$ 733,192**	$ 541,757	$ 191,435
General and administrative	**(9,934)**	(10,158)	224	**(35,576)**	(31,729)	(3,847)
Cash financing and interest	**(26,752)**	(26,343)	(409)	**(83,028)**	(76,384)	(6,644)
Realized financial derivatives gain (loss)	**20,857**	(30,854)	51,711	**52,664**	(70,103)	122,767
Realized foreign exchange (loss) gain	**(382)**	360	(742)	**(426)**	(1,887)	1,461
Other income	**738**	302	436	**5,044**	869	4,175
Current income tax (expense) recovery	**(501)**	—	(501)	**(1,591)**	71	(1,662)
Payments on onerous contracts	**—**	(147)	147	**—**	(439)	439
Adjusted funds flow	**$ 213,379**	$ 171,210	$ 42,169	**$ 670,279**	$ 362,155	$ 308,124
Transaction costs	**—**	(13,066)	13,066	**—**	(13,066)	13,066
Exploration and evaluation	**(2,138)**	(510)	(1,628)	**(8,667)**	(3,887)	(4,780)
Depletion and depreciation	**(180,422)**	(144,501)	(35,921)	**(551,548)**	(364,654)	(186,894)
Share based compensation	**(3,401)**	(7,180)	3,779	**(14,245)**	(15,010)	765
Non-cash financing and accretion	**(5,014)**	(3,686)	(1,328)	**(14,021)**	(10,441)	(3,580)
Unrealized financial derivatives gain (loss)	**7,666**	(46)	7,712	**(30,922)**	(65,140)	34,218
Unrealized foreign exchange (loss) gain	**(13,855)**	20,583	(34,438)	**38,404**	(38,136)	76,540
Gain on dispositions	**18**	34	(16)	**1,075**	1,764	(689)
Deferred income tax (expense) recovery	**(1,082)**	4,427	(5,509)	**14,958**	51,905	(36,947)
Payments on onerous contracts	**—**	147	(147)	**—**	439	(439)
Net income (loss) for the period	**$ 15,151**	$ 27,412	$ (12,261)	**$ 105,313**	$ (94,071)	$ 199,384

We generated adjusted funds flow of $213.4 million for Q3/2019 and $670.3 million for YTD 2019 which is an increase of $42.2 million and $308.1 million from the comparative periods of 2018. Realized gains on financial derivatives of $20.9 million for Q3/2019 more than offset the $8.7 million decrease in operating netback due to the decline in oil and natural gas benchmark prices relative to Q3/2018 when we recorded losses on financial derivatives of $30.9 million. Operating netback for YTD 2019 was $191.4 million higher than YTD 2018 due to increased production along with improved light oil price realizations in Canada and a decrease in our average royalty rate as a result of the Strategic Combination. We recorded realized hedging gains $52.7 million in YTD 2019 compared to realized losses of $70.1 million in the same period in 2018 which also contributed to the $308.1 million increase in adjusted funds flow.

In Q3/2019 we reported net income of $15.2 million compared to $27.4 million in Q3/2018. The $42.2 million increase in adjusted funds flow in Q3/2019 compared to Q3/2018 was offset by a $35.9 million increase in depletion and depreciation expense in Q3/2019 along with an unrealized foreign exchange loss that exceeded gains by $34.4 million relative to Q3/2018. Net income was $105.3 million for YTD 2019 compared to a net loss of $94.1 million in YTD 2018. The increase in net income was driven by the $308.1 million increase in adjusted funds flow and by unrealized losses on financial derivatives and foreign exchange gains which increased net income $110.8 million in YTD 2019 compared to YTD 2018. These increases to net income were offset by an increase in depletion and depreciation expense of $186.9 million along with our deferred tax recovery which was $36.9 million lower in YTD 2019 relative to YTD 2018. Net income for Q3/2018 and YTD 2018 include transaction costs of $13.1 million associated with the Strategic Combination.

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 $25.3 million for Q3/2019 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 September 30, 2019 compared to June 30, 2019. We recorded a foreign currency translation loss of $67.8 million for YTD 2019 due to the strengthening of the Canadian dollar against the U.S. dollar at September 30, 2019 compared to December 31, 2018. The CAD/USD exchange rate was 1.3244 CAD/USD as at September 30, 2019 compared to 1.3091 CAD/USD at June 30, 2019 and 1.3646 CAD/USD as at December 31, 2018.

Capital Expenditures

Capital expenditures for the three and nine months ended September 30, 2019 and 2018 are summarized as follows.

	Three Months Ended September 30					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 85,633**	**$ 38,731**	**$ 124,364**	$ 80,244	$ 42,352	$ 122,596
Facilities	**9,934**	**2,991**	**12,925**	14,106	2,204	16,310
Land, seismic and other	**1,207**	**589**	**1,796**	127	162	289
Total exploration and development	**$ 96,774**	**$ 42,311**	**$ 139,085**	$ 94,477	$ 44,718	$ 139,195
Total acquisitions and property swaps, net of proceeds from divestitures	**$ (30)**	**$ —**	**$ (30)**	$ —	$ —	$ —

	Nine Months Ended September 30					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 228,570**	**$ 120,716**	**$ 349,286**	$ 122,980	$ 123,468	$ 246,448
Facilities	**31,401**	**7,573**	**38,974**	46,474	11,217	57,691
Land, seismic and other	**9,932**	**982**	**10,914**	7,156	264	7,420
Total exploration and development	**$ 269,903**	**$ 129,271**	**$ 399,174**	$ 176,610	$ 134,949	$ 311,559
Total acquisitions and property swaps, net of proceeds from divestitures	**$ 1,617**	**$ —**	**$ 1,617**	$ (2,047)	$ —	$ (2,047)

Exploration and development expenditures were $139.1 million for Q3/2019 and $399.2 million for YTD 2019 compared to $139.2 million for Q3/2018 and $311.6 million for YTD 2018. Higher exploration and development expenditures in YTD 2019 relative to the same periods of 2018 reflects the additional activity associated with our Viking and Duvernay light oil properties which were acquired during Q3/2018 as part of the Strategic Combination.

In Canada, we invested $96.8 million on exploration and development activities in Q3/2019 which is $2.3 million higher than $94.5 million in Q3/2018. Activity levels were lower in Q3/2019 relative to Q3/2018 which only included investment on exploration and development activities for our Viking and Duvernay light oil properties subsequent to acquisition on August 22, 2018. Exploration and development expenditures for Q3/2019 included costs associated with drilling 82 (72.5 net) light oil wells, 20 (20.0 net) heavy oil wells and investing $9.9 million on facilities. Exploration and development expenditures for Q3/2018 included $80.2 million of costs associated with 87 (66.8 net) wells drilled. Exploration and development expenditures of $269.9 million for YTD 2019 included costs associated with drilling 223 (193.7 net) light oil wells, 25 (25.0 net) heavy oil wells and 4 (4.0 net) stratigraphic exploration wells along with $31.4 million of associated facility expenditures. Total exploration and development costs for YTD 2019 were $93.3 million higher than the same period of 2018 primarily due to the investment on our Viking and Duvernay light oil properties which were acquired in Q3/2018.

Total U.S. exploration and development expenditures were $42.3 million for Q3/2019 which is similar to $44.7 million for Q3/2018. During Q3/2019 we participated in the drilling of 22 (5.3 net) wells and commenced production from 20 (4.6 net) wells compared to 29 (8.0 net) wells drilled and 26 (4.9 net) wells on production during Q3/2018. Exploration and development expenditures of $129.3 million for YTD 2019 include costs associated with drilling 65 (14.5 net) wells and bringing 85 (18.5 net) wells on production which is slightly lower than exploration and development expenditures of $134.9 million in YTD 2018 when we drilled 72 (17.5 net) well and commenced production from 85 (18.0 net) wells.

We completed minor acquisition and disposition activity, including property swaps, in YTD 2019 for net consideration of $1.6 million compared to net proceeds of $2.0 million in YTD 2018.

We are forecasting exploration and development expenditures of approximately $560 million for 2019.

CAPITAL RESOURCES AND LIQUIDITY

Our objective for capital management involves maintaining a flexible capital structure and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions and the risk characteristics of our oil and gas properties. At September 30, 2019, our capital structure was comprised of shareholders' capital, long-term notes, working capital and our bank loan.

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.

Management of debt levels is a priority for Baytex in order to sustain operations and support our plans for long-term value creation. At September 30, 2019, net debt was $1,971.3 million, a decrease of $293.9 million from net debt of $2,265.2 million at December 31, 2018. The decrease in net debt is primarily a result of adjusted funds flow exceeding exploration and development expenditures for YTD 2019 by $271.1 million. Net debt was also lower at September 30, 2019 due to a strengthening of the Canadian dollar which resulted in a $32.2 million decrease in the reported principal amount of our U.S. dollar denominated long-term notes relative to December 31, 2018.

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 September 30, 2019, our net debt to adjusted funds flow ratio was 2.5 compared to a ratio of 3.1 as at December 31, 2018. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2018 is attributed to higher adjusted funds flow due to the increase in production in YTD 2019 combined with a $293.9 million decrease in net debt at September 30, 2019.

Bank Loan

At September 30, 2019, the principal amount of bank loan and letters of credit outstanding was $586.2 million and we had approximately $475.3 million of undrawn capacity under our credit facilities that total approximately $1.06 billion. Our credit facilities include US$575 million of revolving credit facilities (the "Revolving Facilities") and a $300 million non-revolving term loan (the "Term Loan").

On May 2, 2019, we amended our credit facilities to extend maturity of the Revolving Facilities and the Term Loan from June 4, 2020 to April 2, 2021. The credit facilities will automatically be extended to June 4, 2021 providing we have either refinanced, or have the ability to repay, the outstanding 2021 long-term notes with existing credit capacity as of April 1, 2021.

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 or will be accessible on the SEDAR website at www.sedar.com (filed under the category "Material contracts" on April 13, 2016, May 2, 2018, October 12, 2018 and May 16, 2019).

The weighted average interest rate on the credit facilities was 4.0% for Q3/2019 and 4.3% for YTD 2019 compared to 4.5% for Q3/2018 and YTD 2018.

Financial Covenants

The following table summarizes the financial covenants applicable to the Revolving Facilities and our compliance therewith at September 30, 2019.

Covenant Description	Position as at September 30, 2019	Covenant
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	**0.66:1.00**	3.50:1.00
Interest Coverage[3] (Minimum Ratio)	**8.02:1.00**	2.00:1.00

(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 September 30, 2019, the Company's Senior Secured Debt totaled $586.2 million which includes $570.8 million of principal amounts outstanding and $15.4 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, 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, 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 September 30, 2019 was $889.4 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended September 30, 2019 were $111.0 million.

Long-Term Notes

On September 13, 2019, we completed the early redemption of the US$150 million principal amount of 6.75% senior unsecured notes which were issued on February 17, 2011. Redemption of these notes was completed at par plus accrued interest at September 13, 2019.

We have three series of long-term notes outstanding that total $1.36 billion as at September 30, 2019. 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 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 2.50:1.00. The fixed charge coverage ratio was 8.02:1.00 as at September 30, 2019.

On July 19, 2012, we issued $300 million principal amount of senior unsecured notes bearing interest at 6.625% payable semi-annually with principal repayable on July 19, 2022. As of July 19, 2017, these notes are redeemable at our option, in whole or in part, at specified redemption prices and will be redeemable at par from July 19, 2020 to maturity.

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the "5.125% Notes") and US$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"). The 5.125% Notes and the 5.625% Notes pay interest semi-annually with the principal amount repayable at maturity. The 5.125% Notes are redeemable at our option, in whole or in part, at par anytime prior to 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.

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 nine months ended September 30, 2019, we issued 3.9 million common shares pursuant to our share-based compensation program. As at October 31, 2019, we had 558.0 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 September 30, 2019 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	**$ 212,404**	$ 212,404	$ —	$ —	$ —
Bank loan[(1) (2)]	**570,792**	—	570,792	—	—
Long-term notes[(2)]	**1,359,480**	—	829,740	529,740	—
Interest on long-term notes[(3)]	**240,189**	76,822	113,649	49,718	—
Lease agreements	**14,815**	6,102	8,517	196	—
Processing agreements	**43,049**	11,541	11,810	8,950	10,748
Transportation agreements	**119,908**	10,791	39,643	39,553	29,921
Total	**$ 2,560,637**	$ 317,660	$ 1,574,151	$ 628,157	$ 40,669

(1) The bank loan matures on April 2, 2021. Maturity will automatically be extended to June 4, 2021 providing Baytex has either refinanced, or has the ability to repay, the outstanding 2021 long-term notes with existing credit capacity as of April 1, 2021.

(2) Principal amount of instruments.

(3) Excludes interest on our bank loan as interest payments fluctuate based on a floating rate of interest and changes in the outstanding balances.

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

QUARTERLY FINANCIAL INFORMATION

($ thousands, except per common share amounts)	**2019**			2018				2017
	Q3	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Petroleum and natural gas sales	**424,600**	482,000	453,424	358,437	436,761	347,605	286,067	303,163
Net income (loss)	**15,151**	78,826	11,336	(231,238)	27,412	(58,761)	(62,722)	76,038
Per common share - basic	**0.03**	0.14	0.02	(0.42)	0.07	(0.25)	(0.27)	0.32
Per common share - diluted	**0.03**	0.14	0.02	(0.42)	0.07	(0.25)	(0.27)	0.32
Adjusted funds flow	**213,379**	236,130	220,770	110,828	171,210	106,690	84,255	105,796
Per common share - basic	**0.38**	0.42	0.40	0.20	0.46	0.45	0.36	0.45
Per common share - diluted	**0.38**	0.42	0.40	0.20	0.45	0.45	0.36	0.44
Exploration and development	**139,085**	106,246	153,843	184,162	139,195	78,830	93,534	90,156
Canada	**96,774**	68,259	104,870	125,507	94,477	30,608	51,525	41,864
U.S.	**42,311**	37,987	48,973	58,655	44,718	48,222	42,009	48,292
Acquisitions, net of divestitures	**(30)**	1,647	—	229	—	(21)	(2,026)	(3,937)
Net debt	**1,971,339**	2,028,686	2,175,241	2,265,167	2,112,090	1,784,835	1,783,379	1,734,284
Total assets	**6,233,875**	6,222,190	6,359,157	6,377,198	6,491,303	4,476,906	4,433,074	4,372,111
Common shares outstanding	**557,972**	556,798	555,872	554,060	553,950	236,662	236,578	235,451
Daily production								
Total production (boe/d)	**94,927**	98,402	101,115	98,890	82,412	70,664	69,522	69,556
Canada (boe/d)	**58,134**	58,580	60,018	60,453	45,214	34,042	33,505	32,194
U.S. (boe/d)	**36,793**	39,822	41,097	38,437	37,198	36,622	36,017	37,362
Benchmark prices								
WTI oil (US$/bbl)	**56.45**	59.81	54.90	58.81	69.50	67.88	62.87	55.40
WCS heavy (US$/bbl)	**44.21**	49.14	42.61	19.39	47.25	48.61	38.59	43.14
CAD/USD avg exchange rate	**1.3207**	1.3376	1.3293	1.3215	1.3070	1.2911	1.2651	1.2717
AECO gas ($/mcf)	**1.04**	1.17	1.94	1.94	1.35	1.03	1.85	1.96
NYMEX gas (US$/mmbtu)	**2.23**	2.64	3.15	3.64	2.90	2.80	3.00	2.93
Sales price ($/boe)	**47.14**	51.49	47.98	37.89	55.03	51.22	42.96	44.75
Royalties ($/boe)	**(8.59)**	(9.67)	(8.94)	(8.77)	(12.13)	(12.01)	(10.36)	(10.86)
Operating expense ($/boe)	**(11.15)**	(11.22)	(11.02)	(10.76)	(10.25)	(10.91)	(10.53)	(10.91)
Transportation expense ($/boe)	**(1.13)**	(1.33)	(1.46)	(1.21)	(1.26)	(1.22)	(1.36)	(1.20)
Operating netback ($/boe)	**26.27**	29.27	26.56	17.15	31.39	27.08	20.71	21.78
Financial derivatives gain (loss) ($/boe)	**2.39**	1.45	2.07	(0.34)	(4.07)	(4.57)	(1.57)	0.30
Operating netback after financial derivatives ($/boe)	**28.66**	30.72	28.63	16.81	27.32	22.51	19.14	22.08

In Q3/2019 we delivered our fourth consecutive quarter of strong operating and financial results following closing of the Strategic Combination in Q3/2018. Production has increased from 69,556 boe/d during Q4/2017 to a high of 101,115 boe/d during Q1/2019 as a result of the Strategic Combination along with our successful development programs in the U.S. and Canada. As planned, production has decreased to 94,927 boe/d in Q3/2019 as a result of decreased capital spending in Q2/2019 and Q3/2019. Improved well productivity from enhanced completion techniques resulted in relatively consistent average daily production in the U.S. despite lower quarterly exploration and development expenditures. In Canada, our exploration and development program was focused on our heavy oil properties at Peace River and Lloydminster. Exploration and development activity in Canada increased following the Strategic Combination with the addition of our light oil Viking and Duvernay properties.

Global benchmark prices for crude oil have fluctuated as attempts to balance the market with production cuts have been mitigated by geopolitical factors and increasing production in North America. Our realized pricing in Canada improved in 2019 after a narrowing of light and heavy oil differentials along with a higher weighting of light oil production following the Strategic Combination. The WCS benchmark averaged US$44.21/bbl in Q3/2019 compared to US$19.39/bbl in Q4/2018 and US$43.14/bbl in Q4/2017.

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 began to improve in late 2017 as commodity prices recovered. Adjusted funds flow continued to improve through Q3/2019 following the Strategic Combination due to increased production and higher realizations associated with the higher weighting of light oil production, as well as strong well performance. The increase in production and operating netback after financial derivatives resulted in adjusted funds flow of $213.4 million in Q3/2019 which is higher than $105.8 million reported in Q4/2017.

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 $1,734.3 million at Q4/2017 to $1,971.3 million at Q3/2019 primarily due to $363.6 million of net debt assumed in conjunction with the Strategic Combination in Q3/2018 combined with an increase in the CAD/USD exchange rate used to translate our U.S. dollar denominated debt from 1.2518 CAD/USD at Q4/2017 to 1.3244 CAD/USD at Q3/2019. The increase in net debt due to the Strategic Combination and a weakening of the Canadian dollar relative to the U.S. dollar was partially offset by adjusted funds flow that exceeded exploration and development expenditures by $264.0 million over the last eight quarters.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at September 30, 2019, 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 nine months ended September 30, 2019 except for the adoption of IFRS 16 as discussed below. 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, 2018.

CHANGES IN ACCOUNTING STANDARDS

Leases

Baytex adopted IFRS 16 *Leases* on January 1, 2019 using the modified retrospective approach. The modified retrospective approach does not require restatement of comparative financial information as it recognizes the cumulative effect on transition as an adjustment to opening retained earnings and applies the standard prospectively. Comparative information in the Company's consolidated statements of financial position, consolidated statements of income (loss) and comprehensive income (loss), consolidated statements of changes in equity, and consolidated statements of cash flows has not been restated.

The cumulative effect of initial application of the standard was to recognize an $18.0 million increase to right-of-use assets ("lease assets"), a $2.0 million reduction of onerous contracts and a $18.0 million increase to lease obligations. Initial measurement of the lease obligation was determined based on the remaining lease payments at January 1, 2019 using a weighted averaged incremental borrowing rate of approximately 3.9%. The lease assets were initially recognized at an amount equal to the lease obligations. The lease assets and lease obligations recognized largely relate to the Company's head office lease in Calgary.

The adoption of IFRS 16 using the modified retrospective approach allowed the Company to use the following practical expedients in determining the opening transition adjustment:

- The weighted average incremental borrowing rate in effect at January 1, 2019 was used as opposed to the rate in effect at inception of the lease;
- Leases with a remaining term of less than 12 months as at January 1, 2019 were accounted for as short-term leases;
- Leases with an underlying asset of low value are recorded as an expense and not recognized as a lease asset;
- Leases with similar characteristics were accounted for as a portfolio using a single discount rate; and
- The Company's previous assessment under IAS 37, *"Provisions, Contingent Liabilities and Contingent Assets'* was used for onerous contracts instead of reassessing the lease assets for impairment at January 1, 2019.

The Company's accounting policy for leases effective January 1, 2019 is set forth below. The Company applied IFRS 16 using the modified retrospective approach. Comparative information continues to be accounted for in accordance with the Company's previous accounting policy found in the 2018 annual financial statements.

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease obligation and corresponding right-of-use asset ("lease asset") are recognized at the commencement of the lease. The present value of the lease obligation is based on the future lease payments and is discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. The Company uses a single discount rate for a portfolio of leases with similar characteristics. The lease asset is recognized at the amount of the lease obligation, adjusted for lease incentives received and initial direct costs, on commencement of the lease. Depreciation is recognized on the lease asset over the shorter of the estimated useful life of the asset or the lease term.

Lease payments are allocated between the liability and interest expense. Interest expense is recognized on the lease obligations using the effective interest rate method and payments are applied against the lease obligation.

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates, and assumptions that affect the reported amount of assets, liabilities, income, and expenses. Actual results could differ significantly from these estimates. Management has made the following judgments, estimates, and assumptions related to the accounting for leases.

The carrying amounts of the right-of-use assets, lease obligations, and the resulting interest and depletion and depreciation expense are based on the implicit interest rate within the lease arrangement or, if this information is unavailable, the incremental borrowing rate. Incremental borrowing rates are based on judgments including economic environment, term, and the underlying risk inherent to the asset.

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, 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, 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, payments on our lease obligations, 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. In addition, we have removed transaction costs associated with the Strategic Combination as we consider the costs non-recurring and are not reflective of our ability to generate adjusted funds flow on an ongoing basis.

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

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2019**	2018	**2019**	2018
Cash flow from operating activities	**$ 194,970**	$ 154,091	**$ 599,920**	$ 316,241
Change in non-cash working capital	**17,275**	1,025	**59,499**	23,633
Asset retirement obligations settled	**1,134**	3,028	**10,860**	9,215
Transaction costs	**—**	13,066	**—**	13,066
Adjusted funds flow	**$ 213,379**	$ 171,210	**$ 670,279**	$ 362,155

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 exploration and development activity 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 September 30		Nine Months Ended September 30	
($ thousands)	**2019**	2018	**2019**	2018
Cash flow used in investing activities	**$ 150,651**	$ 70,194	**$ 447,835**	$ 227,301
Change in non-cash working capital	**(11,577)**	70,396	**(46,646)**	84,113
Proceeds from dispositions	**150**	—	**1,100**	2,234
Property acquisitions	**(120)**	—	**(2,193)**	(187)
Property swaps	**—**	—	**(524)**	—
Additions to other plant and equipment	**(19)**	(1,395)	**(398)**	(1,902)
Exploration and development expenditures	**$ 139,085**	$ 139,195	**$ 399,174**	$ 311,559

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 bank loan and long-term notes outstanding, including trade and other receivables and trade and other payables. 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 final 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.

The following table summarizes our calculation of net debt.

($ thousands)	**September 30, 2019**	December 31, 2018
Bank loan(1)	**$ 570,792**	$ 522,294
Long-term notes(1)	**1,359,480**	1,596,323
Trade and other payables	**212,404**	258,114
Trade and other receivables	**(171,337)**	(111,564)
Net debt	**$ 1,971,339**	$ 2,265,167

(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.

The following table summarizes our calculation of operating netback.

	Three Months Ended September 30		Nine Months Ended September 30	
($ thousands)	**2019**	2018	**2019**	2018
Petroleum and natural gas sales	**$ 424,600**	$ 436,761	**$ 1,360,024**	$ 1,070,433
Blending and other expense	**(12,950)**	(19,548)	**(50,628)**	(55,077)
Total sales, net of blending and other expense	**411,650**	417,213	**1,309,396**	1,015,356
Royalties	**(75,017)**	(91,945)	**(242,959)**	(233,989)
Operating expense	**(97,377)**	(77,698)	**(298,143)**	(213,735)
Transportation expense	**(9,903)**	(9,520)	**(35,102)**	(25,875)
Operating netback	**229,353**	238,050	**733,192**	541,757
Realized financial derivative gain (loss)	**20,857**	(30,854)	**52,664**	(70,103)
Operating netback after realized financial derivatives	**$ 250,210**	$ 207,196	**$ 785,856**	$ 471,654

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 September 30		Nine Months Ended September 30	
($ thousands)	**2019**	2018	**2019**	2018
Net income (loss)	**$ 15,151**	$ 27,412	**$ 105,313**	$ (94,071)
Plus:				
Financing and interest	**31,766**	30,029	**97,049**	86,825
Unrealized foreign exchange (gain) loss	**13,855**	(20,583)	**(38,404)**	38,136
Unrealized financial derivatives (gain) loss	**(7,666)**	46	**30,922**	65,140
Current income tax expense (recovery)	**501**	—	**1,591**	(71)
Deferred income tax expense (recovery)	**1,082**	(4,427)	**(14,958)**	(51,905)
Depletion and depreciation	**180,422**	144,501	**551,548**	364,654
Gain on dispositions	**(18)**	(34)	**(1,075)**	(1,764)
Transaction costs	**—**	13,066	**—**	13,066
Payments on lease obligations	**(1,390)**	—	**(4,402)**	—
Non-cash items(1)	**5,539**	7,690	**22,912**	18,897
Adjustment for Strategic Combination(2)	**—**	96,736	**—**	255,800
Bank EBITDA	**$ 239,242**	$ 294,436	**$ 750,496**	$ 694,707

(1) Non-cash items include share-based compensation and exploration and evaluation expense.
(2) In accordance with the credit facilities agreements, the calculation of Bank EBITDA is adjusted to reflect the impact of material acquisitions as if the transaction had occurred on the first day of the relevant period.

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 September 30, 2019, except for the matter described below.

Baytex previously excluded business processes acquired through the Strategic Combination on August 22, 2018, from the Company's evaluation of internal control over financial reporting as permitted by applicable securities laws in Canada and the U.S. We completed the evaluation and integration of internal controls over financial reporting of Raging River during Q3/2019.

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 capital budget and expected average daily production for 2019; that we expect to exceed our 2019 production guidance; and our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2019; the existence, operation and strategy of our risk management program; that management of our debt levels is a priority; 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 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; 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 nonresidents 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, 2018, 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 September 30, 2019	As at December 31, 2018
ASSETS			
Current assets			
Trade and other receivables		**$ 171,337**	$ 111,564
Financial derivatives	18	**45,318**	79,582
		216,655	191,146
Non-current assets			
Financial derivatives	18	**3,342**	—
Exploration and evaluation assets	5	**337,586**	358,935
Oil and gas properties	6	**5,654,365**	5,817,889
Other plant and equipment		**8,042**	9,228
Lease assets	3	**13,885**	—
		$ 6,233,875	$ 6,377,198
LIABILITIES			
Current liabilities			
Trade and other payables		**$ 212,404**	$ 258,114
Lease obligations	3, 9	**5,659**	—
Onerous contracts	3	**—**	1,986
		218,063	260,100
Non-current liabilities			
Bank loan	7	**569,447**	520,700
Long-term notes	8	**1,349,589**	1,583,240
Lease obligations	3, 9	**8,429**	—
Asset retirement obligations	10	**689,361**	646,898
Deferred income tax liability		**291,849**	310,836
		3,126,738	3,321,774
SHAREHOLDERS' EQUITY			
Shareholders' capital	11	**5,717,237**	5,701,516
Contributed surplus		**17,661**	19,137
Accumulated other comprehensive income		**600,029**	667,874
Deficit		**(3,227,790)**	(3,333,103)
		3,107,137	3,055,424
		$ 6,233,875	$ 6,377,198

See accompanying notes to the condensed consolidated interim unaudited financial statements.

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

		Three Months Ended September 30		Nine Months Ended September 30	
	Notes	**2019**	2018	**2019**	2018
Revenue, net of royalties					
Petroleum and natural gas sales	12	**$ 424,600**	$ 436,761	**$ 1,360,024**	$ 1,070,433
Royalties		**(75,017)**	(91,945)	**(242,959)**	(233,989)
		349,583	344,816	**1,117,065**	836,444
Expenses					
Operating		**97,377**	77,698	**298,143**	213,735
Transportation		**9,903**	9,520	**35,102**	25,875
Blending and other		**12,950**	19,548	**50,628**	55,077
General and administrative		**9,934**	10,158	**35,576**	31,729
Transaction costs		**—**	13,066	**—**	13,066
Exploration and evaluation	5	**2,138**	510	**8,667**	3,887
Depletion and depreciation		**180,422**	144,501	**551,548**	364,654
Share-based compensation	13	**3,401**	7,180	**14,245**	15,010
Financing and interest	16	**31,766**	30,029	**97,049**	86,825
Financial derivatives (gain) loss	18	**(28,523)**	30,900	**(21,742)**	135,243
Foreign exchange loss (gain)	17	**14,237**	(20,943)	**(37,978)**	40,023
Gain on dispositions		**(18)**	(34)	**(1,075)**	(1,764)
Other income		**(738)**	(302)	**(5,044)**	(869)
		332,849	321,831	**1,025,119**	982,491
Net income (loss) before income taxes		**16,734**	22,985	**91,946**	(146,047)
Income tax expense (recovery)	15				
Current income tax expense (recovery)		**501**	—	**1,591**	(71)
Deferred income tax expense (recovery)		**1,082**	(4,427)	**(14,958)**	(51,905)
		1,583	(4,427)	**(13,367)**	(51,976)
Net income (loss)		**$ 15,151**	$ 27,412	**$ 105,313**	$ (94,071)
Other comprehensive income (loss)					
Foreign currency translation adjustment		**25,344**	(39,360)	**(67,845)**	77,096
Comprehensive income (loss)		**$ 40,495**	$ (11,948)	**$ 37,468**	$ (16,975)
Net income (loss) per common share	14				
Basic		**$ 0.03**	$ 0.07	**$ 0.19**	$ (0.33)
Diluted		**$ 0.03**	$ 0.07	**$ 0.19**	$ (0.33)
Weighted average common shares (000's)	14				
Basic		**557,888**	375,435	**556,651**	283,302
Diluted		**560,888**	378,763	**560,438**	283,302

See accompanying notes to the condensed consolidated interim unaudited financial statements.

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

	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	**Total equity**
Balance at December 31, 2017	$ 4,443,576	$ 15,999	$ 463,104	$ (3,007,794)	**$ 1,914,885**
Issued on corporate acquisition	1,238,995	3,100	—	—	**1,242,095**
Issuance costs, net of tax	(316)	—	—	—	**(316)**
Vesting of share awards	19,272	(19,272)	—	—	**—**
Share-based compensation	—	15,010	—	—	**15,010**
Comprehensive income (loss) for the period	—	—	77,096	(94,071)	**(16,975)**
Balance at September 30, 2018	$ 5,701,527	$ 14,837	$ 540,200	$ (3,101,865)	**$ 3,154,699**
Balance at December 31, 2018	$ 5,701,516	$ 19,137	$ 667,874	$ (3,333,103)	**$ 3,055,424**
Vesting of share awards	15,721	(15,721)	—	—	**—**
Share-based compensation	—	14,245	—	—	**14,245**
Comprehensive income (loss) for the period	—	—	(67,845)	105,313	**37,468**
Balance at September 30, 2019	$ 5,717,237	$ 17,661	$ 600,029	$ (3,227,790)	**$ 3,107,137**

See accompanying notes to the condensed consolidated interim unaudited financial statements.

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

		Three Months Ended September 30		Nine Months Ended September 30	
	Notes	**2019**	2018	**2019**	2018
CASH PROVIDED BY (USED IN):					
Operating activities					
Net income (loss) for the period		**$ 15,151**	$ 27,412	**$ 105,313**	$ (94,071)
Adjustments for:					
Share-based compensation	13	**3,401**	7,180	**14,245**	15,010
Unrealized foreign exchange loss (gain)	17	**13,855**	(20,583)	**(38,404)**	38,136
Exploration and evaluation	5	**2,138**	510	**8,667**	3,887
Depletion and depreciation		**180,422**	144,501	**551,548**	364,654
Non-cash financing and accretion	16	**5,014**	3,686	**14,021**	10,441
Unrealized financial derivatives (gain) loss	18	**(7,666)**	46	**30,922**	65,140
Gain on dispositions		**(18)**	(34)	**(1,075)**	(1,764)
Deferred income tax expense (recovery)		**1,082**	(4,427)	**(14,958)**	(51,905)
Payments on onerous contracts		**—**	(147)	**—**	(439)
Asset retirement obligations settled	10	**(1,134)**	(3,028)	**(10,860)**	(9,215)
Change in non-cash working capital		**(17,275)**	(1,025)	**(59,499)**	(23,633)
		194,970	154,091	**599,920**	316,241
Financing activities					
Increase (decrease) in bank loan		**155,199**	(38,305)	**50,445**	(43,348)
Common share issuance costs		**—**	(433)	**—**	(433)
Payments on lease obligations	9	**(1,390)**	—	**(4,402)**	—
Redemption of long-term notes	8	**(198,128)**	—	**(198,128)**	—
		(44,319)	(38,738)	**(152,085)**	(43,781)
Investing activities					
Additions to exploration and evaluation assets	5	**(1,047)**	(2,462)	**(2,441)**	(3,864)
Additions to oil and gas properties	6	**(138,038)**	(136,733)	**(396,733)**	(307,695)
Additions to other plant and equipment		**(19)**	(1,395)	**(398)**	(1,902)
Property acquisitions		**(120)**	—	**(2,193)**	(187)
Property swaps		**—**	—	**(524)**	—
Proceeds from dispositions		**150**	—	**1,100**	2,234
Change in non-cash working capital		**(11,577)**	70,396	**(46,646)**	84,113
		(150,651)	(70,194)	**(447,835)**	(227,301)
Change in cash		**—**	45,159	**—**	45,159
Cash, beginning of period		**—**	—	**—**	—
Cash, end of period		**$ —**	$ 45,159	**$ —**	$ 45,159
Supplementary information					
Interest paid		**$ 22,315**	$ 20,708	**$ 78,493**	$ 70,406
Income taxes paid		**$ 76**	$ 10	**$ 1,158**	$ —

See accompanying notes to the condensed consolidated interim unaudited 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, 2018.

The consolidated financial statements were approved by the Board of Directors of Baytex on October 31, 2019.

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. 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, 2018 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 2018 annual financial statements have been applied in the preparation of these consolidated financial statements, except for the adoption of IFRS 16 *Leases* as described below.

Changes in significant accounting policies

Leases

Baytex adopted IFRS 16 *Leases* on January 1, 2019 using the modified retrospective approach. The modified retrospective approach does not require restatement of comparative financial information as it recognizes the cumulative effect on transition as an adjustment to opening retained earnings and applies the standard prospectively. Comparative information in the Company's consolidated statements of financial position, consolidated statements of income (loss) and comprehensive income (loss), consolidated statements of changes in equity, and consolidated statements of cash flows has not been restated.

The cumulative effect of initial application of the standard was to recognize an $18.0 million increase to right-of-use assets ("lease assets"), a $2.0 million reduction of onerous contracts and a $18.0 million increase to lease obligations. Initial measurement of the lease obligation was determined based on the remaining lease payments at January 1, 2019 using a weighted averaged incremental borrowing rate of approximately 3.9%. The lease assets were initially recognized at an amount equal to the lease obligations. The lease assets and lease obligations recognized largely relate to the Company's head office lease in Calgary.

The adoption of IFRS 16 using the modified retrospective approach allowed the Company to use the following practical expedients in determining the opening transition adjustment:

- The weighted average incremental borrowing rate in effect at January 1, 2019 was used as opposed to the rate in effect at inception of the lease;
- Leases with a remaining term of less than 12 months as at January 1, 2019 were accounted for as short-term leases;
- Leases with an underlying asset of low value are recorded as an expense and not recognized as a lease asset;
- Leases with similar characteristics were accounted for as a portfolio using a single discount rate; and
- Used the Company's previous assessment under IAS 37, *"Provisions, Contingent Liabilities and Contingent Assets'* for onerous contracts instead of reassessing the lease assets for impairment at January 1, 2019.

The Company's accounting policy for leases effective January 1, 2019 is set forth below. The Company applied IFRS 16 using the modified retrospective approach. Comparative information continues to be accounted for in accordance with the Company's previous accounting policy found in the 2018 annual financial statements.

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease obligation and corresponding right-of-use asset ("lease asset") are recognized at the commencement of the lease. The present value of the lease obligation is based on the future lease payments and is discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. The Company uses a single discount rate for a portfolio of leases with similar characteristics. The lease asset is recognized at the amount of the lease obligation, adjusted for lease incentives received and initial direct costs, on commencement of the lease. Depreciation is recognized on the lease asset over the shorter of the estimated useful life of the asset or the lease term.

Lease payments are allocated between the liability and interest expense. Interest expense is recognized on the lease obligations using the effective interest rate method and payments are applied against the lease obligation.

The preparation of the consolidated financial statements in accordance with IFRS requires management to make judgments, estimates, and assumptions that affect the reported amount of assets, liabilities, income, and expenses. Actual results could differ significantly from these estimates. Management has made the following judgments, estimates, and assumptions related to the accounting for leases.

The carrying amounts of the right-of-use assets, lease obligations, and the resulting interest and depletion and depreciation expense are based on the implicit interest rate within the lease arrangement or, if this information is unavailable, the incremental borrowing rate. Incremental borrowing rates are based on judgments including economic environment, term, and the underlying risk inherent to the asset.

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 United States; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended September 30	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 258,769**	$ 217,805	**$ 165,831**	$ 218,956	**$ —**	$ —	**$ 424,600**	$ 436,761
Royalties	**(26,193)**	(26,139)	**(48,824)**	(65,806)	**—**	—	**(75,017)**	(91,945)
	232,576	191,666	**117,007**	153,150	**—**	—	**349,583**	344,816
Expenses								
Operating	**73,701**	54,710	**23,676**	22,988	**—**	—	**97,377**	77,698
Transportation	**9,903**	9,520	**—**	—	**—**	—	**9,903**	9,520
Blending and other	**12,950**	19,548	**—**	—	**—**	—	**12,950**	19,548
General and administrative	**—**	—	**—**	—	**9,934**	10,158	**9,934**	10,158
Transaction costs	**—**	—	**—**	—	**—**	13,066	**—**	13,066
Exploration and evaluation	**2,138**	510	**—**	—	**—**	—	**2,138**	510
Depletion and depreciation	**116,316**	77,083	**63,572**	66,830	**534**	588	**180,422**	144,501
Share-based compensation	**—**	—	**—**	—	**3,401**	7,180	**3,401**	7,180
Financing and interest	**—**	—	**—**	—	**31,766**	30,029	**31,766**	30,029
Financial derivatives (gain) loss	**—**	—	**—**	—	**(28,523)**	30,900	**(28,523)**	30,900
Foreign exchange loss (gain)	**—**	—	**—**	—	**14,237**	(20,943)	**14,237**	(20,943)
Gain on dispositions	**(18)**	(34)	**—**	—	**—**	—	**(18)**	(34)
Other income	**—**	—	**—**	—	**(738)**	(302)	**(738)**	(302)
	214,990	161,337	**87,248**	89,818	**30,611**	70,676	**332,849**	321,831
Net income (loss) before income taxes	**17,586**	30,329	**29,759**	63,332	**(30,611)**	(70,676)	**16,734**	22,985
Income tax expense (recovery)								
Current income tax expense	**—**	—	**501**	—	**—**	—	**501**	—
Deferred income tax expense (recovery)	**4,734**	4,134	**(203)**	9,278	**(3,449)**	(17,839)	**1,082**	(4,427)
	4,734	4,134	**298**	9,278	**(3,449)**	(17,839)	**1,583**	(4,427)
Net income (loss)	**$ 12,852**	$ 26,195	**$ 29,461**	$ 54,054	**$ (27,162)**	$ (52,837)	**$ 15,151**	$ 27,412
Total oil and natural gas capital expenditures(1)	**$ 96,744**	$ 94,477	**$ 42,311**	$ 44,718	**$ —**	$ —	**$ 139,055**	$ 139,195

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

Nine Months Ended September 30	Canada 2019	Canada 2018	U.S. 2019	U.S. 2018	Corporate 2019	Corporate 2018	Consolidated 2019	Consolidated 2018
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 817,506**	$ 471,742	**$ 542,518**	$ 598,691	**$ —**	$ —	**$ 1,360,024**	$ 1,070,433
Royalties	**(82,313)**	(55,471)	**(160,646)**	(178,518)	**—**	—	**(242,959)**	(233,989)
	735,193	416,271	**381,872**	420,173	**—**	—	**1,117,065**	836,444
Expenses								
Operating	**221,680**	147,054	**76,463**	66,681	**—**	—	**298,143**	213,735
Transportation	**35,102**	25,875	**—**	—	**—**	—	**35,102**	25,875
Blending and other	**50,628**	55,077	**—**	—	**—**	—	**50,628**	55,077
General and administrative	**—**	—	**—**	—	**35,576**	31,729	**35,576**	31,729
Transaction costs	**—**	—	**—**	—	**—**	13,066	**—**	13,066
Exploration and evaluation	**8,667**	3,887	**—**	—	**—**	—	**8,667**	3,887
Depletion and depreciation	**347,661**	170,514	**202,303**	192,212	**1,584**	1,928	**551,548**	364,654
Share-based compensation	**—**	—	**—**	—	**14,245**	15,010	**14,245**	15,010
Financing and interest	**—**	—	**—**	—	**97,049**	86,825	**97,049**	86,825
Financial derivatives (gain) loss	**—**	—	**—**	—	**(21,742)**	135,243	**(21,742)**	135,243
Foreign exchange (gain) loss	**—**	—	**—**	—	**(37,978)**	40,023	**(37,978)**	40,023
Gain on dispositions	**(1,075)**	(1,764)	**—**	—	**—**	—	**(1,075)**	(1,764)
Other income	**—**	—	**—**	—	**(5,044)**	(869)	**(5,044)**	(869)
	662,663	400,643	**278,766**	258,893	**83,690**	322,955	**1,025,119**	982,491
Net income (loss) before income taxes	**72,530**	15,628	**103,106**	161,280	**(83,690)**	(322,955)	**91,946**	(146,047)
Income tax expense (recovery)								
Current income tax expense (recovery)	**—**	—	**1,591**	(71)	**—**	—	**1,591**	(71)
Deferred income tax expense (recovery)	**8,842**	(197)	**4,505**	15,951	**(28,305)**	(67,659)	**(14,958)**	(51,905)
	8,842	(197)	**6,096**	15,880	**(28,305)**	(67,659)	**(13,367)**	(51,976)
Net income (loss)	**$ 63,688**	$ 15,825	**$ 97,010**	$ 145,400	**$ (55,385)**	$ (255,296)	**$ 105,313**	$ (94,071)
Total oil and natural gas capital expenditures(1)	**$ 271,520**	$ 174,563	**$ 129,271**	$ 134,949	**$ —**	$ —	**$ 400,791**	$ 309,512

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

As at	September 30, 2019	December 31, 2018
Canadian assets	**$ 3,758,068**	$ 3,739,029
U.S. assets	**2,467,765**	2,628,941
Corporate assets	**8,042**	9,228
Total consolidated assets	**$ 6,233,875**	$ 6,377,198

5. EXPLORATION AND EVALUATION ASSETS

	September 30, 2019	December 31, 2018
Balance, beginning of period	**$ 358,935**	$ 272,974
Capital expenditures	**2,441**	10,567
Corporate acquisition	**—**	97,858
Property acquisitions	**1,473**	514
Divestitures	**(132)**	(1,021)
Property swaps	**417**	—
Exploration and evaluation expense	**(8,667)**	(21,729)
Transfer to oil and gas properties	**(12,421)**	(13,866)
Foreign currency translation	**(4,460)**	13,638
Balance, end of period	**$ 337,586**	$ 358,935

6. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2017	**$ 7,932,327**	**$ (3,974,018)**	**$ 3,958,309**
Capital expenditures	485,154	—	485,154
Corporate acquisition	1,748,368	—	1,748,368
Property acquisitions	202	—	202
Transfers from exploration and evaluation assets	13,866	—	13,866
Change in asset retirement obligations	238,662	—	238,662
Divestitures	(15)	—	(15)
Impairment	—	(285,341)	(285,341)
Foreign currency translation	325,969	(110,651)	215,318
Depletion	—	(556,634)	(556,634)
Balance, December 31, 2018	**$ 10,744,533**	**$ (4,926,644)**	**$ 5,817,889**
Capital expenditures	396,733	—	396,733
Property acquisitions	1,328	—	1,328
Transfers from exploration and evaluation assets	12,421	—	12,421
Change in asset retirement obligations (note 10)	45,342	—	45,342
Divestitures	(2,069)	1,690	(379)
Property swaps	(5,754)	4,694	(1,060)
Foreign currency translation	(121,053)	50,489	(70,564)
Depletion	—	(547,345)	(547,345)
Balance, September 30, 2019	**$ 11,071,481**	**$ (5,417,116)**	**$ 5,654,365**

7. BANK LOAN

	September 30, 2019	December 31, 2018
Bank loan - U.S. dollar denominated(1)	**$ 269,205**	$ 122,388
Bank loan - Canadian dollar denominated	**301,587**	399,906
Bank loan - principal	**570,792**	522,294
Unamortized debt issuance costs	**(1,345)**	(1,594)
Bank loan	**$ 569,447**	$ 520,700

(1) U.S. dollar denominated bank loan balance was US$203.3 million as at September 30, 2019 (December 31, 2018 - US$89.7 million).

Baytex has US$575 million of revolving credit facilities (the "Revolving Facilities") and a $300 million non-revolving term loan (the "Term Loan") (collectively the "Credit Facilities"). On May 2, 2019, Baytex amended its Credit Facilities to extend maturity from June

4, 2020 to April 2, 2021. These facilities will automatically be extended to June 4, 2021 providing Baytex has either refinanced, or has the ability to repay, the outstanding 2021 long-term notes with existing credit capacity as of April 1, 2021.

The extendible secured Revolving Facilities are comprised of a US$50 million operating loan (previously US$35 million) and a US $325 million syndicated revolving loan for Baytex (previously US$340 million) and a US$200 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. and matures on April 2, 2021. The Term Loan is secured by the assets of Baytex's wholly-owned subsidiary, Baytex Energy Limited Partnership and matures on April 2, 2021.

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 September 30, 2019, Baytex had $15.4 million of outstanding letters of credit (December 31, 2018 - $14.6 million) under the Credit Facilities.

At September 30, 2019, Baytex was in compliance with all of the covenants contained in the Credit Facilities. The following table summarizes the financial covenants applicable to the Revolving Facilities and Baytex's compliance therewith as at September 30, 2019.

Covenant Description	**Position as at September 30, 2019**	**Covenant**
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	**0.66:1.00**	**3.50:1.00**
Interest Coverage[3] (Minimum Ratio)	**8.02:1.00**	**2.00:1.00**

(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 September 30, 2019, the Company's Senior Secured Debt totaled $586.2 million which includes $570.8 million of principal amounts outstanding and $15.4 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, 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, 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 September 30, 2019 was $889.4 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended September 30, 2019 were $111.0 million.

8. LONG-TERM NOTES

	September 30, 2019	December 31, 2018
6.75% notes (US$150,000 – principal) due February 17, 2021	**$ —**	$ 204,683
5.125% notes (US$400,000 – principal) due June 1, 2021	**529,740**	545,820
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	**300,000**	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	**529,740**	545,820
Total long-term notes - principal	**1,359,480**	1,596,323
Unamortized debt issuance costs	**(9,891)**	(13,083)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,349,589**	$ 1,583,240

On September 13, 2019, Baytex completed the early redemption of the US$150,000 principal amount of 6.75% senior unsecured notes, due February 17, 2021. The total principal payment was $198.1 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 fixed charge coverage ratio (computed as the ratio of Bank EBITDA (as defined in note 7) to financing and interest expenses on a trailing twelve month basis) of 2.50:1.00. At September 30, 2019, the fixed charge coverage ratio was 8.02:1.00.

9. LEASE OBLIGATIONS

Baytex had the following future commitments associated with its lease obligations at September 30, 2019.

		September 30, 2019
Less than 1 year	**$**	**6,102**
1 - 3 years		**8,517**
3 - 5 years		**196**
After 5 years		**—**
Total lease payments		**14,815**
Amounts representing interest over the term of the lease		**(727)**
Present value of net lease payments		**14,088**
Less current portion of lease obligations		**5,659**
Non-current portion of lease obligations	**$**	**8,429**

The Company recorded interest related to its lease obligations of $0.1 million and $0.5 million for the three and nine months ended September 30, 2019. The Company recorded lease payments of $1.4 million and $4.4 million for the three and nine months ended September 30, 2019.

10. ASSET RETIREMENT OBLIGATIONS

		September 30, 2019		December 31, 2018
Balance, beginning of period	**$**	**646,898**	$	368,995
Liabilities incurred		**16,873**		12,537
Liabilities settled		**(10,860)**		(14,035)
Liabilities assumed from corporate acquisition		**—**		39,960
Liabilities acquired from property acquisitions		**608**		132
Liabilities divested		**(424)**		(580)
Property swaps		**(1,229)**		—
Accretion (note 16)		**10,268**		10,914
Change in estimate		**(2,435)**		33,453
Changes in discount rates and inflation rates(1)		**30,904**		192,672
Foreign currency translation		**(1,242)**		2,850
Balance, end of period	**$**	**689,361**	$	646,898

(1) The discount and inflation rates at September 30, 2019 were 1.75%, compared to 2.15% and 2.00%, respectively, at December 31, 2018.

11. 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 September 30, 2019, 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 meetings 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, 2017	**235,451**	**$ 4,443,576**
Vesting of share awards	3,343	19,496
Issued on corporate acquisition	315,266	1,238,995
Issuance costs, net of tax	—	(551)
Balance, December 31, 2018	**554,060**	**$ 5,701,516**
Vesting of share awards	3,912	15,721
Balance, September 30, 2019	**557,972**	**$ 5,717,237**

12. PETROLEUM AND NATURAL GAS SALES

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

	Three Months Ended September 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 134,921**	**$ 140,344**	**$ 275,265**	$ 69,557	$ 170,402	$ 239,959
Heavy oil	**117,961**	**—**	**117,961**	139,305	—	139,305
NGL	**1,486**	**11,045**	**12,531**	4,147	30,508	34,655
Natural gas sales	**4,401**	**14,442**	**18,843**	4,796	18,046	22,842
Total petroleum and natural gas sales	**$ 258,769**	**$ 165,831**	**$ 424,600**	$ 217,805	$ 218,956	$ 436,761

	Nine Months Ended September 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 409,117**	**$ 442,763**	**$ 851,880**	$ 79,894	$ 476,086	$ 555,980
Heavy oil	**381,684**	**—**	**381,684**	364,957	—	364,957
NGL	**6,684**	**47,656**	**54,340**	11,595	71,480	83,075
Natural gas sales	**20,021**	**52,099**	**72,120**	15,296	51,125	66,421
Total petroleum and natural gas sales	**$ 817,506**	**$ 542,518**	**$ 1,360,024**	$ 471,742	$ 598,691	$ 1,070,433

Included in accounts receivable at September 30, 2019 is $138.6 million (December 31, 2018 - $77.4 million) of accrued production revenue related to deliveries for periods ended prior to the reporting date.

13. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to the share awards of $3.4 million and $14.2 million for the three and nine months ended September 30, 2019 ($7.2 million and $15.0 million for the three and nine months ended September 30, 2018).

The weighted average fair value of share awards granted was $2.63 per restricted and performance award for the nine months ended September 30, 2019 ($4.04 per restricted and performance award for the nine months ended September 30, 2018).

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, 2017	**2,028**	**2,253**	**4,281**
Granted	2,793	2,591	5,384
Assumed on corporate acquisition	302	257	559
Vested and converted to common shares	(1,682)	(1,661)	(3,343)
Forfeited	(198)	(167)	(365)
Balance, December 31, 2018	**3,243**	**3,273**	**6,516**
Granted	3,158	3,245	6,403
Vested and converted to common shares	(1,902)	(2,010)	(3,912)
Forfeited	(281)	(315)	(596)
Balance, September 30, 2019	**4,218**	**4,193**	**8,411**

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

Share Options

Baytex inherited 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.

(000s, except per common share amounts)	Number of options		Weighted average exercise price
Balance, December 31, 2017	**—**	**$**	**—**
Assumed on corporate acquisition	9,187		6.63
Forfeited/Expired	(4,322)		6.57
Balance, December 31, 2018	**4,865**	**$**	**6.70**
Forfeited/Expired	(1,468)		6.24
Balance, September 30, 2019	**3,397**	**$**	**6.90**

	Options Outstanding				**Options Exercisable**		
Exercise price	Number outstanding at September 30, 2019 (000s)	Weighted average remaining life (years)		Weighted average exercise price	Number exercisable at September 30, 2019 (000s)		Weighted average exercise price
$5.00 - $7.00	1,957	1.09	$	6.32	1,175	$	6.40
$7.01 - $9.00	1,440	0.29		7.68	1,326		7.66
Total	**3,397**	**0.75**	**$**	**6.90**	**2,501**	**$**	**7.07**

14. 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. 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 September 30						
	2019			2018		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	Net income	Weighted average common shares (000s)	Net income per share
Net income - basic	**$ 15,151**	**557,888**	**$ 0.03**	$ 27,412	375,435	$ 0.07
Dilutive effect of share awards	**—**	**3,000**	**—**	—	3,328	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net income - diluted	**$ 15,151**	**560,888**	**$ 0.03**	$ 27,412	378,763	$ 0.07

Nine Months Ended September 30						
	2019			2018		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	Net loss	Weighted average common shares (000s)	Net loss per share
Net income (loss) - basic	**$ 105,313**	**556,651**	**$ 0.19**	$ (94,071)	283,302	$ (0.33)
Dilutive effect of share awards	**—**	**3,787**	**—**	—	—	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net income (loss) - diluted	**$ 105,313**	**560,438**	**$ 0.19**	$ (94,071)	283,302	$ (0.33)

For the three and nine months ended September 30, 2019, no share awards were considered to be anti-dilutive. For the three months ended September 30, 2018, no share awards were considered to be anti-dilutive and for the nine months ended September 30, 2018, 6.7 million share awards were excluded from the calculation of diluted earnings per share as they were determined to be anti-dilutive. For the three and nine months ended September 30, 2019, 3.4 million share options were excluded from the calculation of diluted earnings per share as they were determined to be anti-dilutive (8.7 million for the three and nine months ended September 30, 2018).

15. INCOME TAXES

The provision for income taxes has been computed as follows:

	Nine Months Ended September 30	
	2019	2018
Net income (loss) before income taxes	**$ 91,946**	$ (146,047)
Expected income taxes at the statutory rate of 26.72% (2018 – 27.00%)	**24,568**	(39,433)
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	**3,806**	3,963
Non-taxable portion of foreign exchange (gain) loss	**(5,179)**	5,201
Effect of change in income tax rates	**(10,573)**	—
Effect of rate adjustments for foreign jurisdictions	**(20,965)**	(27,400)
Effect of change in deferred tax benefit not recognized(1)	**(4,803)**	5,201
Adjustments and assessments	**(221)**	492
Income tax recovery	**$ (13,367)**	$ (51,976)

(1) A deferred income tax asset has not been recognized for accumulated allowable capital losses of $120 million (December 31, 2018 - $139 million) related to foreign exchange losses on long-term notes.

For the nine months ended September 30, 2019, the deferred tax recovery includes $10.6 million attributable to decreases in the Alberta provincial income tax rate for the periods from July 1, 2019 to January 1, 2022, which reduces the provincial rate to 11% effective July 1, 2019, and further reduces it by 1% on January 1st for each of the years 2020, 2021 and 2022, bringing the provincial rate to 8%.

As disclosed in the 2018 annual financial statements, Baytex received several reassessments from the Canada Revenue Agency (the “CRA”) in June 2016 which denied $591 million of non-capital loss deductions that Baytex had previously claimed. 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 our file in July 2018. Baytex remains confident that its original tax filings are correct and intends to defend those tax filings through the appeals process.

16. FINANCING AND INTEREST

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
Interest on bank loan	**$ 4,650**	$ 4,108	**$ 15,171**	$ 10,297
Interest on long-term notes	**21,955**	22,235	**67,382**	66,087
Interest on lease obligations	**147**	—	**475**	—
Non-cash financing	**1,607**	866	**3,753**	2,991
Accretion on asset retirement obligations (note 10)	**3,407**	2,820	**10,268**	7,450
Financing and interest	**$ 31,766**	$ 30,029	**$ 97,049**	$ 86,825

17. FOREIGN EXCHANGE

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
Unrealized foreign exchange loss (gain)	**$ 13,855**	$ (20,583)	**$ (38,404)**	$ 38,136
Realized foreign exchange loss (gain)	**382**	(360)	**426**	1,887
Foreign exchange loss (gain)	**$ 14,237**	$ (20,943)	**$ (37,978)**	$ 40,023

18. 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, bank loan, long-term notes, and lease obligations. The fair value of the bank loan 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 consolidated statements of financial position are classified into the following categories:

	September 30, 2019		December 31, 2018		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL[(1)]					
Financial derivatives	**$ 48,660**	**$ 48,660**	$ 79,582	$ 79,582	Level 2
Total	**$ 48,660**	**$ 48,660**	$ 79,582	$ 79,582	
Financial assets at amortized cost					
Trade and other receivables	**$ 171,337**	**$ 171,337**	$ 111,564	$ 111,564	—
Total	**$ 171,337**	**$ 171,337**	$ 111,564	$ 111,564	
Financial Liabilities					
Financial liabilities at amortized cost					
Trade and other payables	**$ (212,404)**	**$ (212,404)**	$ (258,114)	$ (258,114)	—
Bank loan	**(569,447)**	**(570,792)**	(520,700)	(522,294)	—
Long-term notes	**(1,349,589)**	**(1,315,950)**	(1,583,240)	(1,492,363)	Level 1
Lease obligations	**(14,088)**	**(14,088)**	—	—	—
Total	**$ (2,145,528)**	**$ (2,113,234)**	$ (2,362,054)	$ (2,272,771)	

(1) FVTPL means fair value through profit or loss.

There were no transfers between Level 1 and Level 2 during the nine months ended September 30, 2019 and 2018.

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	
	September 30, 2019	December 31, 2018	**September 30, 2019**	December 31, 2018
U.S. dollar denominated	**US$41,939**	US$80,857	**US$853,897**	US$963,351

Interest Rate Risk

Interest Rate Swaps

Baytex had the following interest rate swaps outstanding as of October 31, 2019:

Contract Type	Notional Amount	Maturity Date	Fixed Contract Price	Reference[1]	Fair Value *($ millions)*
Interest rate swap	$100 million	October 2020	2.02%	CDOR	$ —
Total					**$ —**

(1) Canadian Dollar Offered Rate.

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of October 31, 2019:

	Remaining Period	Volume	Price/Unit[1]	Index		Fair Value[2] *($ millions)*
Oil						
Basis Swap	Oct 2019 to Dec 2019	7,000 bbl/d	WTI less US$17.59/bbl	WCS	$	(2.5)
Basis Swap	Oct 2019 to Dec 2019	4,000 bbl/d	WTI less US$8.00/bbl	MSW	$	(0.8)
Basis Swap	Jan 2020 to Dec 2020	2,500 bbl/d	WTI less US$16.10/bbl	WCS	$	0.2
Fixed - Sell	Oct 2019 to Dec 2019	12,000 bbl/d	US$62.35/bbl	WTI	$	12.4
Fixed - Sell	Oct 2019 to Dec 2019	2,000 bbl/d	US$65.50/bbl	Brent	$	1.7
Fixed - Sell [6]	Jan 2020 to Mar 2020	4,000 bbl/d	US$55.90/bbl	WTI	$	—
3-way option[3]	Oct 2019 to Dec 2019	2,000 bbl/d	US$49.00/US$61.70/US$75.00	WTI	$	1.8
3-way option[3]	Oct 2019 to Dec 2019	2,000 bbl/d	US$50.00/US$60.00/US$70.00	WTI	$	1.4
3-way option[3]	Oct 2019 to Dec 2019	1,000 bbl/d	US$55.00/US$65.00/US$72.60	WTI	$	1.0
3-way option[3]	Oct 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$72.50	WTI	$	1.0
3-way option[3]	Oct 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$73.00	WTI	$	1.0
3-way option[3]	Oct 2019 to Dec 2019	2,000 bbl/d	US$57.00/US$67.00/US$73.00	WTI	$	2.2
3-way option[3]	Oct 2019 to Dec 2019	2,000 bbl/d	US$58.00/US$68.00/US$74.00	WTI	$	2.2
3-way option[3]	Oct 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$69.90/US$75.00	WTI	$	1.1
3-way option[3]	Oct 2019 to Dec 2019	1,000 bbl/d	US$61.00/US$71.00/US$76.00	WTI	$	1.2
3-way option[3]	Oct 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$78.00	WTI	$	1.2
3-way option[3]	Oct 2019 to Dec 2019	1,000 bbl/d	US$55.50/US$65.50/US$75.50	Brent	$	0.7
3-way option[3]	Oct 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$70.00/US$77.55	Brent	$	1.0
3-way option[3]	Oct 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$83.00	Brent	$	1.1
3-way option[3]	Jan 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$56.00/US$61.35	WTI	$	2.0
3-way option[3]	Jan 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$57.00/US$60.00	WTI	$	2.4
3-way option[3][6]	Jan 2020 to Dec 2020	3,000 bbl/d	US$50.00/US$57.00/US$62.00	WTI	$	—
3-way option[3]	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI	$	2.6
3-way option[3]	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI	$	2.7
3-way option[3]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI	$	1.9
3-way option[3]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI	$	2.1
3-way option[3]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI	$	2.1
3-way option[3]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI	$	2.1
3-way option[3]	Jan 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	WTI	$	4.3
Swaption[4]	Jan 2020 to Dec 2020	1,000 bbl/d	US$62.50/bbl	WTI	$	(0.1)
Swaption[4]	Jan 2020 to Dec 2020	1,000 bbl/d	US$63.20/bbl	WTI	$	(0.1)
Swaption[5]	Jan 2021 to Dec 2021	3,000 bbl/d	US$60.75/bbl	WTI	$	(2.2)
Swaption[5][6]	Jan 2021 to Dec 2021	3,000 bbl/d	US$70.00/bbl	Brent	$	—
Natural Gas						
Fixed - Sell	Oct 2019 to Dec 2019	15,000 mmbtu/d	US$2.97	NYMEX	$	0.9
Total					**$**	**48.6**
Financial derivatives - Current asset						45.3
Financial derivatives - Non-current asset						3.3

(1) Based on the weighted average price per unit for the period.
(2) Fair values as at September 30, 2019.
(3) Producer 3-way option consists of a sold put, a bought put and a sold call. To illustrate, in a US$50/US$60/US$70 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50/bbl; Baytex receives US$60.00/bbl when WTI is between US$50/bbl and US$60/bbl; Baytex receives the market price when WTI is between US$60/bbl and US$70/bbl; and Baytex receives US$70/bbl when WTI is above US $70/bbl.
(4) For these contracts, the counterparty has the right, if exercised on December 31, 2019, 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 30, 2020, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.
(6) Contracts entered subsequent to September 30, 2019.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2019	2018	**2019**	2018
Realized financial derivatives (gain) loss	**$ (20,857)**	$ 30,854	**$ (52,664)**	$ 70,103
Unrealized financial derivatives (gain) loss	**(7,666)**	46	**30,922**	65,140
Financial derivatives (gain) loss	**$ (28,523)**	$ 30,900	**$ (21,742)**	$ 135,243

Physical Delivery Contracts

The following physical delivery contracts were held for the purpose of delivery of non-financial items in accordance with the Company'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 consolidated statements of financial position.

As at October 31, 2019, Baytex had committed to deliver the following volumes of raw bitumen to market on rail:

Remaining Period	Volume
Oct 2019	1,000 bbl/d
Oct 2019 to Dec 2019	11,000 bbl/d
Jan 2020 to Dec 2020	7,500 bbl/d

CORPORATE INFORMATION

BOARD OF DIRECTORS

Neil J. Roszell
Chairman of the Board

Edward D. LaFehr
President and Chief Executive Officer
Baytex Energy Corp.

Mark R. Bly (2)(3)
Lead Independent Director

Trudy M. Curran (2)(4)
Director

Naveen Dargan (1)(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 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

M. Scott Lovett
Vice President, Corporate Development

Chad E. Lundberg
Vice President, Light Oil

Scott E. Rideout
Vice President, Land

AUDITORS

KPMG LLP

RESERVES ENGINEERS

Sproule Associates Limited
Ryder Scott Company L.P.
GLJ Petroleum Consultants Ltd.

TRANSFER AGENT

Computershare Trust Company of Canada

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE