BAYTEX
ENERGY CORP.

Q1 REPORT / 2019

PRESS RELEASE

CALGARY, ALBERTA (May 2, 2019) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three months ended March 31, 2019 (all amounts are in Canadian dollars unless otherwise noted).

“This marks the first quarter where we have demonstrated the benefit of the Baytex and Raging River combination as we have increased our operating netback, delivered meaningful free cash flow and started to strengthen our balance sheet. Our first quarter results were underpinned by robust operating performance across our asset base in Canada and the U.S. Our sound operating results, combined with improved pricing in Canada, resulted in a 100% increase in our adjusted funds flow compared to the fourth quarter of 2018. We are well positioned to execute our business plan focused on free cash flow generation,” commented Ed LaFehr, President and Chief Executive Officer.

2019 Outlook

Based on the forward strip for 2019[1], we are now forecasting adjusted funds flow for 2019 of approximately $950 million. Further deleveraging remains a top priority with adjusted funds flow now exceeding the midpoint of our capital guidance by $350 million, which will support accelerated debt repayment.

Given our strong operating performance to date, we are tightening our 2019 production guidance range to 95,000 to 97,000 boe/d (previously 93,000 to 97,000 boe/d) with budgeted exploration and development capital expenditures of $575 to $625 million (previously $550 to $650 million).

(1) Pricing assumptions: WTI - US$61/bbl; LLS - US$67/bbl; WCS differential - US$15/bbl; MSW differential – US$6/bbl, NYMEX Gas - US$2.80/mcf; AECO Gas - $1.50/mcf and Exchange Rate (CAD/USD) - 1.34.

Q1/2019 Highlights

- Generated production of 101,115 boe/d (84% oil and NGL), exceeding the high end of our annual guidance and a 2% increase over Q4/2018.
- Delivered adjusted funds flow of $221 million ($0.40 per basic share), a 100% increase compared to $111 million ($0.20 per basic share) in Q4/2018.
- Reduced net debt by $90 million during the quarter as adjusted funds flow exceeded capital expenditures.
- Realized an operating netback of $26.56/boe ($28.63/boe including financial derivatives).
- Eagle Ford production increased 7% to 41,097 boe/d, representing the highest quarterly production rate achieved in the field and reflects continued strong well performance and an active first quarter completion program.
- Production in Canada remained strong at 60,018 boe/d. We maintained a consistent development program in the Viking and reinitiated activity on our heavy oil assets, including the completion of three previously deferred wells at Peace River.
- Continued to advance the evaluation of the East Duvernay Shale where two of four planned wells were drilled. Completion activities are scheduled to commence in Q2/2019 to confirm well productivities and the de-risking of the majority of our 250 sections of land in the Pembina area.
- Extended the maturity of our revolving credit facilities to April 2021. We maintain strong financial liquidity with our credit facilities approximately 50% undrawn.

	Three Months Ended		
	March 31, 2019	December 31, 2018	March 31, 2018
FINANCIAL (thousands of Canadian dollars, except per common share amounts)			
Petroleum and natural gas sales	**$ 453,424**	$ 358,437	$ 286,067
Adjusted funds flow (1)	**220,770**	110,828	84,255
Per share - basic	**0.40**	0.20	0.36
Per share - diluted	**0.40**	0.20	0.36
Net income (loss)	**11,336**	(231,238)	(62,722)
Per share - basic	**0.02**	(0.42)	(0.27)
Per share - diluted	**0.02**	(0.42)	(0.27)
Capital Expenditures			
Exploration and development expenditures (1)	**$ 153,843**	$ 184,162	$ 93,534
Acquisitions, net of divestitures	**-**	183	(2,026)
Total oil and natural gas capital expenditures	**$ 153,843**	$ 184,345	$ 91,508
Net Debt			
Bank loan (2)	**$ 550,751**	$ 522,294	$ 212,571
Long-term notes (2)	**1,569,153**	1,596,323	1,525,595
Long-term debt	**2,119,904**	2,118,617	1,738,166
Working capital deficiency	**55,337**	146,550	45,213
Net debt (1)	**$ 2,175,241**	$ 2,265,167	$ 1,783,379
Shares Outstanding - basic (thousands)			
Weighted average	**555,438**	554,036	236,315
End of period	**555,872**	554,060	236,578

	Three Months Ended		
	March 31, 2019	December 31, 2018	March 31, 2018
OPERATING			
Daily Production			
Light oil and condensate (bbl/d)	**45,048**	44,987	20,967
Heavy oil (bbl/d)	**26,891**	26,339	24,868
NGL (bbl/d)	**11,729**	10,327	9,143
Total liquids (bbl/d)	**83,668**	81,653	54,978
Natural gas (mcf/d)	**104,682**	103,424	87,261
Oil equivalent (boe/d @ 6:1) (3)	**101,115**	98,890	69,522
Netback (thousands of Canadian dollars)			
Total sales, net of blending and other expense (4)	**$ 436,636**	$ 344,682	$ 268,777
Royalties	**(81,325)**	(79,765)	(64,839)
Operating expense	**(100,292)**	(97,857)	(65,888)
Transportation expense	**(13,330)**	(10,994)	(8,519)
Operating netback	**$ 241,689**	$ 156,066	$ 129,531
General and administrative	**(14,136)**	(14,096)	(11,008)
Cash financing and interest	**(28,184)**	(27,933)	(24,511)
Realized financial derivatives gain (loss)	**18,814**	(3,063)	(9,841)
Other (5)	**2,587**	(146)	84
Adjusted funds flow (1)	**$ 220,770**	$ 110,828	$ 84,255
Netback (per boe)			
Total sales, net of blending and other expense (4)	**$ 47.98**	$ 37.89	$ 42.96
Royalties	**(8.94)**	(8.77)	(10.36)
Operating expense	**(11.02)**	(10.76)	(10.53)
Transportation expense	**(1.46)**	(1.21)	(1.36)
Operating netback (1)	**$ 26.56**	$ 17.15	$ 20.71
General and administrative	**(1.55)**	(1.55)	(1.76)
Cash financing and interest	**(3.10)**	(3.07)	(3.92)
Realized financial derivatives gain (loss)	**2.07**	(0.34)	(1.57)
Other (5)	**0.28**	(0.02)	0.01
Adjusted funds flow (1)	**$ 24.26**	$ 12.17	$ 13.47

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. We refer you to 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 liquidity or repayment obligations.

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

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

(5) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and payments on onerous contracts. Refer to the Q1/2019 MD&A for further information on these amounts.

Operating Results

Our operating results for the first quarter of 2019 were buoyed by record production in the Eagle Ford and strong operating performance in Canada in a much improved commodity price environment. We successfully executed our first quarter drilling program and continued to drive cost and capital efficiency in our business. We are now realizing the benefits of the Baytex and Raging River combination as we increase our operating netback, deliver meaningful free cash flow and strengthen our balance sheet.

Production during the first quarter averaged 101,115 boe/d (84% oil and NGL), as compared to 98,890 boe/d (83% oil and NGL) in Q4/2018, exceeding the high end of our full-year production guidance range.

Exploration and development expenditures totaled $154 million in Q1/2019, consistent with the mid-point of our guidance range of $600 million. We participated in the drilling of 126 (86.6 net) wells with a 99% success rate during the first quarter.

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 41,097 boe/d (78% liquids) during Q1/2019, as compared to 38,437 boe/d in Q4/2018. This represents the highest quarterly production rate ever achieved in the field and reflects continued strong well performance and an active first quarter completion program. We commenced production from 36 (8.9 net) wells during the first quarter, representing approximately one-third of our planned 2019 activity. The wells brought on-stream generated an average 30-day initial production rate of approximately 1,600 boe/d per well.

During Q1/2019, production from the Viking averaged 23,387 boe/d, as compared to 23,784 boe/d in Q4/2018. We maintained a steady pace of development in Q1/2019 with five drilling rigs and 1.5 frac crews executing our program, resulting in 79 (67.8 net) wells. We continue to experience positive results from our extended reach horizontal drilling program, which now represents 85% of our Viking activity. Our capital program includes the seasonal slowdown in Q2/2019 and we remain on track to drill approximately 250 net wells this year.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 29,341 boe/d during the first quarter, as compared to 28,290 boe/d in Q4/2018. As commodity prices and operating netbacks improved during the first quarter, we reinitiated field activity, including the completion of three previously deferred wells at Peace River. In addition, we continued the ramp-up of our Kerrobert thermal expansion project achieving a peak production rate of 2,500 bbl/d. We have also expanded our acreage position at Peace River, acquiring an additional 26 sections of prospective land. We expect to drill our first exploratory multilateral well on these lands in 2019.

With WCS differentials returning to historical levels, the returns associated with continued development of our heavy oil assets are now competitive or superior to those of our other plays, allowing potential increased capital allocation to those assets in the second half of 2019.

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 where we have amassed over 450 sections of land. During Q1/2019, we drilled two of four planned land retention and appraisal wells. The wells drilled to date have confirmed that the net reservoir thickness and geological characteristics remain consistent through the southern extent of our Pembina acreage. Completion activities are scheduled to commence in Q2/2019 to confirm well productivities and the de-risking of the majority of our 250 sections of land in the Pembina area.

Financial Review

Our adjusted funds flow in Q1/2019 increased 100% as compared to Q4/2018, driven by strong operating performance and the cash generating capability of our assets in an improved commodity price environment. We generated adjusted funds flow of $221 million ($0.40 per basic share) in Q1/2019, compared to $111 million ($0.20 per basic share) in Q4/2018.

In Q1/2019, the price for West Texas Intermediate light oil (“WTI”) averaged US$54.90/bbl, as compared to US$58.81/bbl in Q4/2018. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select (“WCS”) and WTI, averaged US$12.29/bbl in Q1/2019 as compared to US$39.42/bbl in Q4/2018. The discount for Canadian light oil, as measured by the price differential between Canadian Mixed Sweet Blend ("MSW") and WTI, averaged US$4.85/bbl in Q1/2019 as compared to US$26.51/bbl in Q4/2018.

We generated an operating netback of $26.56/boe in Q1/2019, as compared to $17.15/boe in Q4/2018 and $20.71/boe in Q1/2018. The Eagle Ford generated an operating netback of $28.94/boe during Q1/2019 while our Canadian operations generated an operating netback of $24.92/boe.

In the Eagle Ford, our assets are proximal to Gulf Coast markets with light oil and condensate production priced off the LLS crude oil benchmark, which is a function of the Brent price. In Q1/2019, the price for LLS averaged US$61.60/bbl as compared to US$66.64/bbl in Q4/2018. During Q1/2019, our light oil and condensate realized price in the Eagle Ford was US$57.23/bbl (or $76.06/bbl) representing a US$4.37/bbl discount to LLS.

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

	Three Months Ended March 31					
	2019			2018		
($ per boe except for production)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Production (boe/d)	**60,018**	**41,097**	**101,115**	33,505	36,017	69,522
Total sales, net of blending and other [(1)]	**$ 45.77**	**$ 51.20**	**$ 47.98**	$ 29.69	$ 55.30	$ 42.96
Royalties	**(4.66)**	**(15.18)**	**(8.94)**	(3.76)	(16.51)	(10.36)
Operating expense	**(13.72)**	**(7.08)**	**(11.02)**	(15.06)	(6.31)	(10.53)
Transportation expense	**(2.47)**	**—**	**(1.46)**	(2.83)	—	(1.36)
Operating netback [(2)]	**$ 24.92**	**$ 28.94**	**$ 26.56**	$ 8.04	$ 32.48	$ 20.71
Realized financial derivatives gain (loss)	**—**	**—**	**2.07**	—	—	(1.57)
Operating netback after financial derivatives	**$ 24.92**	**$ 28.94**	**$ 28.63**	$ 8.04	$ 32.48	$ 19.14

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. We refer you to the advisory on non-GAAP measures at the end of this press release.

Financial Liquidity

On May 2, 2019, we extended the maturity of our revolving credit facilities to April 2021. The credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews. Our credit facilities total approximately $1.07 billion, comprised of US$575 million of revolving credit facilities and a $300 million non-revolving term loan.

Our net debt, which includes our bank loan, long-term notes and working capital, totaled $2.2 billion at March 31, 2019, down from $2.3 billion at December 31, 2018. We maintain strong financial liquidity with our credit facilities approximately 50% undrawn and our first long-term note maturity not until 2021.

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, crude-by-rail and capital allocation optimization to reduce the volatility in our adjusted funds flow. We realized a financial derivatives gain of $19 million in Q1/2019.

For the balance of 2019, we have now entered into hedges on approximately 45% of our net crude oil exposure, up from approximately 30% two months ago. This includes 40% of our net WTI exposure with 17% fixed at US$62.72/bbl and 23% 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. In addition, we have entered into a Brent-based 3-way option structure for 3,000 bbl/d that provides a US$10/bbl premium to Brent when Brent is at or below US$59.50/bbl and allows upside participation to US$78.68/bbl. We have also entered into hedges on approximately 22% of our net natural gas exposure through a series of NYMEX swaps at US$3.10/mmbtu. For 2020, we have entered into hedges on approximately 15% of our net crude oil exposure, utilizing a 3-way option structure that provides us with a US$9/bbl premium to WTI when WTI is at or below US$51.00/bbl and allows upside participation to US$66.06/bbl.

Crude-by-rail is an integral part of our egress and marketing strategy for our heavy oil production. For 2019, we expect to deliver 11,000 bbl/d (approximately 40%) of our heavy oil volumes to market by rail, up from 9,000 bbl/d in 2018. Approximately 70% of our crude by rail commitments are WTI based contracts with no WCS pricing exposure. In addition, for the balance of 2019, we have entered into WCS differential hedges on approximately 13% of our net heavy oil exposure at a WTI-WCS differential of US$17.49/bbl. We have also entered into a WTI-MSW basis differential swap for 4,000 bbl/d of our light oil production in Canada at US$8/bbl for June 2019 to December 2019.

A complete listing of our financial derivative contracts can be found in Note 18 to our Q1/2019 financial statements.

Outlook for 2019

Global benchmark prices have continued to improve with WTI currently trading at US$64/bbl, as compared to an average of US$55/bbl in Q1/2019. In addition, Canadian light and heavy oil differentials remain strong. For April and May, the WTI-WCS price differential averaged US$10.62/bbl and US$8.43/bbl, respectively, and the WTI-MSW price differential averaged US$4.69/bbl and US$3.70/bbl, respectively. This combination of improved WTI prices and the narrowing of Canadian differentials is expected to have a further positive impact to our full year adjusted funds flow.

Given our strong Q1/2019 operating performance, we are tightening our 2019 production guidance range to 95,000 to 97,000 boe/d (previously 93,000 to 97,000 boe/d) with budgeted exploration and development capital expenditures of $575 to $625 million (previously $550 to $650 million). We are also updating our guidance for general and administrative expense to reflect a change associated with the adoption of IFRS 16.

Based on the forward strip for 2019[(1)], we are forecasting adjusted funds flow of approximately $950 million. Further deleveraging remains a top priority. For 2019, adjusted funds flow in excess of exploration and development expenditures, leasing expenditures and asset retirement obligations, will be used to reduce our indebtedness. Our year end 2019 net debt to adjusted funds flow ratio is forecast to be 2.0x.

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, the reinstatement of a dividend and/or share buybacks.

The following table summarizes our updated 2019 annual guidance.

	Guidance	Q1/2019
Exploration and development capital ($ millions) [(2)]	$575 - $625	$153.8
Production (boe/d) [(2)]	95,000 - 97,000	101,115
Expenses:		
Royalty rate (%)	20%	18.6%
Operating ($/boe)	$10.75 - $11.25	$11.02
Transportation ($/boe)	$1.25 - $1.35	$1.46
General and administrative ($ millions)	$46 ($1.30/boe)	$14.1 ($1.55/boe)
Interest ($ millions)	$112 ($3.23/boe)	$28.2 ($3.10/boe)
Leasing expenditures ($ millions)	$5	1.4
Asset retirement obligations ($ millions)	$17	4.9

(1) Pricing assumptions: WTI - US$61/bbl; LLS - US$67/bbl; WCS differential - US$15/bbl; MSW differential – US$6/bbl, NYMEX Gas - US$2.80/mcf; AECO Gas - $1.50/mcf and Exchange Rate (CAD/USD) - 1.34.

(2) Our exploration and development capital and production guidance for 2019 has been updated as of May 2, 2019. Original guidance from December 2018: production – 93,000-97,000 boe/d; exploration and development capital - $550-$650 million.

The following table summarizes our annual adjusted funds flow sensitivities to changes in commodity prices and the CAD/USD exchange rate.

	Excluding Hedges ($ millions)	Including Hedges ($ millions)
Change of US$1.00/bbl WTI crude oil	$29.1	$21.3
Change of US$1.00/bbl WCS heavy oil differential	$11.3	$9.3
Change of US$1.00/bbl MSW light oil differential	$10.6	$10.6
Change of US$0.25/mcf NYMEX natural gas	$9.2	$7.3
Change of $0.01 in the CAD/USD exchange rate	$12.2	$12.2

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; that we are focused on free cash flow generation; our forecast for adjusted funds flow and debt repayment; that deleveraging is a top priority; our 2019 production and capital expenditure guidance; that we expect to drill 250 wells in the Viking play in 2019; that we expect to drill an exploratory well on new lands in Peace River in 2019; that WCS differentials mean that our heavy oil assets are competitive or superior to our other assets and could be allocated more capital in H2/2019; that we continue to prudently advance the delineation of our East Duvernay Shale assets and the timing and impact of our planned completion activities in the East Duvernay; 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; the expected impact of improved pricing on our adjusted funds flow; that deleveraging remains a priority and our planned uses for adjusted funds flow in 2019; our forecast year end 2019 net dent 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 our 2019 production, capital expenditure guidance, adjusted funds flow, adjusted funds flow per share and operating netback guidance; our expected royalty rate and operating, transportation, general and administration and interest expenses for 2019; our expected leasing expenditures and asset retirement obligation spending for 2019; the sensitivity of our 2019 Adjusted Funds Flow to changes in WTI, WCS, MSW and NYMEX prices and the C$/US$ exchange rate. 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 months ended March 31, 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 liquidity or repayment obligation.

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

Advisory Regarding Oil and Gas Information

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

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

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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MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the three months ended March 31, 2019. This information is provided as of May 2, 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 months ended March 31, 2019 ("Q1/2019") have been compared with the results for the three months ended March 31, 2018 ("Q1/2018"). This MD&A should be read in conjunction with the Company's condensed consolidated interim unaudited financial statements ("consolidated financial statements") for the three months ended March 31, 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 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% high operating netback light oil from the Viking and Duvernay. The addition of the primarily operated assets to our portfolio increased our inventory of drilling prospects and increased our ability to effectively allocate capital.

FIRST QUARTER HIGHLIGHTS

Baytex delivered solid operating and financial results in Q1/2019. Our adjusted funds flow was $220.8 million which exceeded $153.8 million spent on exploration and development activities and contributed to a $89.9 million reduction in net debt. Production for Q1/2019 exceeded the high end of our annual guidance range of 93,000 to 97,000 boe/d and averaged 101,115 boe/d due to strong well performance in the U.S. and Canada.

In the U.S., production of 41,097 boe/d for Q1/2019 increased 7% from 38,437 boe/d in Q4/2018 and 14% from 36,017 boe/d for Q1/2018 due to strong well performance and from higher completion activity on our lands. We invested $49.0 million on exploration and development activities during Q1/2019 and drilled 23 (3.6 net) wells and brought 36 (8.9 net) wells on production. Higher completion activity resulted in exploration and development expenditures that were $7.0 million higher than Q1/2018 when we invested $42.0 million and drilled 25 (6.9 net) wells and commenced production from 27 (5.5 net) wells.

In Canada, exploration and development expenditures of $104.9 million were focused on our Viking and Duvernay light oil properties. Exploration and development expenditures included costs associated with drilling 98 (78.3 net) light oil wells, 1 (1.0 net) heavy oil well and 4 (4.0 net) stratigraphic exploration wells during Q1/2019. Production of 60,018 boe/d for Q1/2019 increased 79% from 33,505 boe/d in Q1/2018 which reflects the impact of the Strategic Combination along with an increase in heavy oil production from our 2018 development program. Production in Q1/2019 is consistent with 60,453 boe/d for Q4/2018 despite production curtailments mandated by the Government of Alberta which became effective in January 2019.

The West Texas Intermediate ("WTI") Benchmark price for crude oil was lower in Q1/2019 compared to both Q4/2018 and Q1/2018. The WTI oil price averaged US$54.90/bbl in Q1/2019 which was down US$7.97/bbl from US$62.87/bbl in Q1/2018 and down US $3.91/bbl from US$58.81/bbl in Q4/2018. In 2018, light and heavy oil differentials in Canada were impacted by increasing oil production and a lack of egress in Western Canada and traded at wider differentials to WTI relative to previous years. Production curtailments mandated by the Government of Alberta came into effect in January of 2019 and have helped narrow Canadian light and heavy oil differentials in Q1/2019. The Edmonton par light oil benchmark averaged $66.53/bbl in Q1/2019 which represents a differential of US $4.85/bbl to WTI as compared to a US$26.51 differential in Q4/2018 and a US$5.91/bbl differential in Q1/2018. The Western Canadian Select ("WCS") heavy oil differential averaged US$12.29/bbl in Q1/2019 relative to a differential of US$39.42 in Q4/2018 and US $24.27/bbl in Q1/2018.

We generated adjusted funds flow of $220.8 million in Q1/2019 which is $136.5 million higher than $84.3 million for Q1/2018. The increase in adjusted funds flow was a result of higher realized pricing and the 45% increase in production for Q1/2019 relative to Q1/2018. Our realized price of $47.98/boe for Q1/2019 increased $5.02/boe from $42.96/boe for Q1/2018 and reflects stronger pricing received on our Canadian light oil production and narrower WCS differentials. The increase in our realized price was partially offset by higher total royalties, operating and transportation expense in Q1/2019 and resulted in a $112.2 million increase in operating netback relative to Q1/2018. Realized hedging gains of $18.8 million also contributed to the increase in adjusted funds flow relative to Q1/2018 when we recorded realized hedging losses of $9.8 million.

In Q1/2019 we reported net income of $11.3 million compared to a net loss of $62.7 million in Q1/2018. The $136.5 million increase in adjusted funds flow was offset by higher depletion and depreciation of $77.1 million and higher unrealized losses on our financial derivatives of $35.6 million. We also recorded a foreign exchange gain on our US denominated long-term notes of $26.9 million compared to a loss of $36.0 million during Q1/2018 which resulted in a $63.0 million increase in net income during Q1/2019.

At March 31, 2019, net debt was $2,175.2 million, a decrease of $89.9 million from $2,265.2 million at December 31, 2018. Adjusted funds flow exceeded exploration and development expenditures for Q1/2019 and resulted in a $66.9 million reduction in net debt. The Canadian dollar also strengthened at March 31, 2019 which reduced the reported amount of our US denominated long-term notes by $27.2 million.

2019 GUIDANCE

The following table compares our 2019 annual guidance to our Q1/2019 results. As a result of our strong operational performance in Q1/2019 we are tightening our 2019 production guidance range to 95,000 to 97,000 boe/d with budgeted exploration and development expenditures of $575 to $625 million. We are also updating our guidance for general and administrative expense to reflect a change associated with the adoption of IFRS 16.

	Original Annual Guidance (1)	Revised Annual Guidance	Q1/2019
Exploration and development capital	$550 - 650 million	$575 - 625 million	$153.8 million
Production (boe/d)	93,000 to 97,000	95,000 to 97,000	101,115
Expenses:			
Royalty rate	~ 20.0%	No change	18.6%
Operating	$10.75 - $11.25/boe	No change	$11.02/boe
Transportation	$1.25 - $1.35/boe	No change	$1.46/boe
General and administrative	~ $44 million ($1.27/boe)	~ $46 million ($1.30/boe)	$14.1 million ($1.55/boe)
Cash interest	~ $112 million ($3.23/boe)	No change	$28.2 million ($3.10/boe)

(1) As announced on December 17, 2018.

RESULTS OF OPERATIONS

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

Production

	Three Months Ended March 31					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**23,295**	**21,753**	**45,048**	859	20,108	20,967
Heavy oil	**26,891**	**—**	**26,891**	24,868	—	24,868
Natural Gas Liquids (NGL)	**1,608**	**10,121**	**11,729**	1,299	7,844	9,143
Total liquids (bbl/d)	**51,794**	**31,874**	**83,668**	27,026	27,952	54,978
Natural gas (mcf/d)	**49,346**	**55,336**	**104,682**	38,873	48,388	87,261
Total production (boe/d)	**60,018**	**41,097**	**101,115**	33,505	36,017	69,522
Production Mix						
Light oil and condensate	**39%**	**53%**	**45%**	3%	56%	30%
Heavy oil	**45%**	**—%**	**27%**	74%	—%	36%
NGL	**3%**	**25%**	**12%**	4%	22%	13%
Natural gas	**13%**	**22%**	**16%**	19%	22%	21%

We reported production of 101,115 boe/d for Q1/2019 which exceeded the high end of our annual guidance range of 95,000 to 97,000 boe/d. Production for Q1/2019 was 31,593 boe/d higher than 69,522 boe/d in Q1/2018 due to the Strategic Combination combined with higher completion activity in the U.S. and our successful heavy oil development program in Canada.

In Canada, production was 60,018 boe/d for Q1/2019 compared to 33,505 boe/d in Q1/2018. The increase in production in Q1/2019 relative to Q1/2018 is primarily due to the production contribution from the Strategic Combination along with strong production results from our heavy oil development program. Production from our Viking and Duvernay properties consists of approximately 90% light oil which resulted in a higher portion of our Canadian production being comprised of light oil in Q1/2019 relative to Q1/2018.

Production in the U.S. averaged 41,097 boe/d for Q1/2019 which is higher than 36,017 boe/d for Q1/2018. Strong well performance and higher completion activity during Q1/2019 resulted in average daily production that was 5,080 boe/d higher than 36,017 boe/d in Q1/2018. During Q1/2019 we commenced production from 36 (8.9 net) wells compared to Q1/2018 when 27 (5.5 net) wells were brought on production.

We have narrowed our annual production guidance range for 2019 from 93,000 - 97,000 boe/d to 95,000 to 97,000 boe/d, increasing the midpoint of our range by 1,000 boe/d reflecting the positive performance in Q1/2019. We are expecting a decrease in our production in Q2/2019 with seasonal declines in Canada and lower activity levels in the Eagle Ford.

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 were lower in Q1/2019 after increasing production and geopolitical factors contributed to a sharp decline in global oil prices in Q4/2018. Waivers granted by the United States mitigated the impact of sanctions on Iranian production which became effective in November 2018 and resulted in a significant decline in oil prices leading into 2019. As a result, the WTI benchmark price averaged US$54.90/bbl during Q1/2019, representing an decrease of US$7.97/bbl compared to Q1/2018 when the benchmark price averaged US$62.87/bbl.

Our U.S. crude oil production is primarily priced off the Louisiana Light Sweet ("LLS") stream at St. James, Louisiana, which is the representative benchmark for light oil pricing at the U.S. Gulf coast. During Q1/2019, LLS averaged US$61.60/bbl, or a premium of US$6.70/bbl relative to WTI, compared to an LLS price of US$67.07/bbl or a US$4.20/bbl premium to WTI for Q1/2018.

Ongoing pipeline capacity constraints, a lack of rail transport capacity and increasing Western Canadian crude oil production resulted in benchmark pricing trading at a wider discount to WTI with the WCS heavy differential averaging US$39.42/bbl and the Edmonton par differential averaging US$26.51/bbl during Q4/2018. Production curtailments mandated by the Government of Alberta have narrowed the Canadian oil differentials in Q1/2019 and resulted in the WCS heavy differential averaging US$12.29/bbl and the Edmonton par differential averaging US$4.85/bbl for Q1/2019.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $66.53/bbl for Q1/2019 compared to $72.06/bbl for Q1/2018 as the decrease in WTI more than offset the narrower differential in Q1/2019 compared to Q1/2018. Edmonton par traded at a US$4.85/bbl discount to WTI in Q1/2019 compared to a US $5.91/bbl discount for Q1/2018. 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. The WCS heavy oil differential to WTI averaged US$12.29/bbl in Q1/2019 as compared to US$24.27/bbl for Q1/2018. As a result, the WCS heavy oil benchmark price of $56.64/bbl increased $7.81/bbl from $48.83/bbl in Q1/2018 despite a $6.56/bbl decrease in WTI (expressed in Canadian dollars) over the same periods.

Natural Gas

North American natural gas prices for Q1/2019 were fairly consistent with Q1/2018 as increased demand due to cold weather in Q1/2019 mitigated the impact of significant North American natural gas supply growth. Canadian natural gas prices remained challenged during Q1/2019 as a lack of egress in 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. During Q1/2019 the NYMEX natural gas benchmark averaged US$3.15/mmbtu which is consistent with US$3.00/mmbtu for the same period of 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 $1.94/mcf during Q1/2019 which is consistent with $1.85/mcf for Q1/2018.

The following tables compare selected benchmark prices and our average realized selling prices for the three months ended March 31, 2019 and 2018.

	Three Months Ended March 31		
	2019	2018	Change
Benchmark Averages			
WTI oil (US$/bbl)(1)	**54.90**	62.87	(7.97)
LLS oil (US$/bbl)(2)	**61.60**	67.07	(5.47)
LLS oil differential to WTI (US$/bbl)	**6.70**	4.20	2.50
Edmonton par oil ($/bbl)	**66.53**	72.06	(5.53)
Edmonton par oil differential to WTI (US$/bbl)	**(4.85)**	(5.91)	1.06
WCS heavy oil ($/bbl) (3)	**56.64**	48.83	7.81
WCS heavy oil differential to WTI (US$/bbl)	**(12.29)**	(24.27)	11.98
AECO natural gas price ($/mcf)(4)	**1.94**	1.85	0.09
NYMEX natural gas price (US$/mmbtu)(5)	**3.15**	3.00	0.15
CAD/USD average exchange rate	**1.3293**	1.2651	0.0642

(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 March 31					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices[(1)]						
Light oil and condensate ($/bbl)	**$ 63.14**	**$ 76.06**	**$ 69.38**	$ 62.78	$ 79.90	$ 79.20
Heavy oil ($/bbl)[(2)]	**41.69**	**—**	**41.69**	33.33	—	33.33
NGL ($/bbl)	**23.77**	**22.84**	**22.97**	28.72	25.75	26.17
Natural gas ($/mcf)	**2.37**	**3.95**	**3.21**	1.92	3.78	2.95
Weighted average ($/boe)[(2)]	**$ 45.77**	**$ 51.20**	**$ 47.98**	$ 29.69	$ 55.30	$ 42.96

(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 $47.98/boe for Q1/2019 which is up $5.02/boe from $42.96/boe for Q1/2018. Our realized price in the U.S. was $51.20/boe in Q1/2019 which is $4.10/boe lower than $55.30/boe in Q1/2018 due to the decrease in U.S. crude oil benchmark prices. In Canada, our realized price of $45.77/boe for Q1/2019 was $16.08/boe higher than $29.69/boe for Q1/2018 due to a narrowing of Canadian light and heavy oil differentials during Q1/2019 combined with an improvement in our realized pricing following the Strategic Combination.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price of $63.14/bbl was slightly higher than $62.78/bbl in Q1/2018 despite a $5.53/bbl decrease in the benchmark price. The improvement in our Canadian light oil price realizations can be attributed to our Viking and Duvernay light oil properties acquired in Q3/2018 which achieve stronger pricing than our legacy light oil properties in Canada.

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 $76.06/bbl for Q1/2019 which is a $3.84/bbl decrease compared to $79.90/bbl for Q1/2018. Expressed in U.S. dollars, our realized light oil and condensate price of US$57.22/bbl represents a US$4.38/bbl discount to the LLS benchmark for Q1/2019 which is fairly consistent with a US$3.91/bbl discount for Q1/2018.

Our realized heavy oil price, net of blending and other expense averaged $41.69/bbl in Q1/2019 which is $8.36/bbl higher than $33.33/bbl in Q1/2018. The $8.36/bbl increase in our realized heavy oil price for Q1/2019 is a result of a narrower Canadian heavy oil differential which resulted in a $7.81/bbl increase in the WCS benchmark relative to Q1/2018 despite a lower WTI benchmark price.

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 of the underlying products. In Canada, our realized NGL price was $23.77/bbl in Q1/2019 or 33% of WTI (expressed in Canadian dollars) which is relatively consistent with $28.72/bbl or 36% of WTI in Q1/2018. Our U.S. NGL realized price was $22.84/bbl or 31% of WTI (expressed in Canadian dollars) as compared to $25.75/bbl or 32% of WTI (expressed in Canadian dollars) for Q1/2018. The decline in our realized NGL pricing in Q1/2019 compared to Q1/2018 is a result of the decline in market pricing as our realization as a percentage of WTI was relatively consistent over the periods.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price for Q1/2019 was $2.37/mcf representing an increase of $0.45/mcf from $1.92/mcf in Q1/2018 compared to a $0.09/mcf increase in the AECO monthly benchmark over the same periods. A portion of our natural gas sales in Canada are referenced to the AECO daily benchmark price which was $0.55/mcf higher in Q1/2019 relative to Q1/2018 which resulted in our realized price being higher than the monthly benchmark price.

Our realized natural gas price in the U.S. was $3.95/mmbtu for Q1/2019 and $3.78/mmbtu in Q1/2018 which is fairly consistent with the NYMEX benchmark (expressed in Canadian dollars) of $4.19/mmbtu in Q1/2019 and $3.80/mmbtu for Q1/2018.

Petroleum and Natural Gas Sales

	Three Months Ended March 31					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 132,368**	**$ 148,916**	**$ 281,284**	$ 4,851	$ 144,607	$ 149,458
Heavy oil	**117,686**	**—**	**117,686**	91,883	—	91,883
NGL	**3,441**	**20,802**	**24,243**	3,356	18,178	21,534
Total oil sales	**253,495**	**169,718**	**423,213**	100,090	162,785	262,875
Natural gas sales	**10,544**	**19,667**	**30,211**	6,724	16,468	23,192
Total petroleum and natural gas sales	**264,039**	**189,385**	**453,424**	106,814	179,253	286,067
Blending and other expense	**(16,788)**	**—**	**(16,788)**	(17,290)	—	(17,290)
Total sales, net of blending and other expense	**$ 247,251**	**$ 189,385**	**$ 436,636**	$ 89,524	$ 179,253	$ 268,777

Total sales, net of blending and other expense, was $436.6 million for Q1/2019 which is an increase of $167.9 million from $268.8 million reported for Q1/2018 due to a combination of increased production and realized prices. Higher production in Q1/2019 increased total sales by $136.4 million relative to Q1/2018 while stronger realized pricing from the narrowing of Canadian oil differentials combined with a higher weighting of light oil production in Q1/2019 increased sales by $31.5 million compared to Q1/2018.

In Canada, total sales, net of blending and other expense, was $247.3 million for Q1/2019 which is an increase of $157.7 million from Q1/2018. Total petroleum and natural gas sales increased with production due to the Strategic Combination and our successful heavy oil exploration and development program. The increase in our average realized price of $45.77/boe for Q1/2019 also contributed to higher total sales, net of blending and other expense compared to Q1/2018 when our weighted average realized price was $29.69/boe.

Petroleum and natural gas sales in the U.S. were $189.4 million for Q1/2019 and increased $10.1 million from $179.3 million reported for Q1/2018. The 5,080 boe/d increase in production from Q1/2019 compared to Q1/2018 increased total sales by $23.4 million. This was offset by lower realized prices which were $4.10/boe lower in Q1/2019 compared to Q1/2018 and decreased total sales by $13.3 million.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three months ended March 31, 2019 and 2018.

	Three Months Ended March 31					
	2019			2018		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 25,184**	**$ 56,141**	**$ 81,325**	$ 11,334	$ 53,505	$ 64,839
Average royalty rate[1]	**10.2%**	**29.6%**	**18.6%**	12.7%	29.8%	24.1%
Royalty rate per boe	**$ 4.66**	**$ 15.18**	**$ 8.94**	$ 3.76	$ 16.51	$ 10.36

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

Royalties for Q1/2019 were $81.3 million and averaged 18.6% of total sales, net of blending and other expense, compared to $64.8 million or 24.1% for Q1/2018. Total royalty expense is higher in Q1/2019 due to higher total sales, net of blending and other expense, in Canada and the U.S. relative to Q1/2018. Our Canadian royalty rate of 10.2% for Q1/2019 was lower than 12.7% for Q1/2018 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 Q1/2018 averaged 29.6% of total petroleum and natural gas sales which is consistent with Q1/2018 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

Our average royalty rate of 18.6% for Q1/2019 is slightly lower than our annual guidance of approximately 20.0% as our Canadian sales, that have a lower royalty rate, represented a higher percentage of total sales. We expect our royalty rate for the remainder of 2019 to be in line with our annual guidance of approximately 20.0%.

Operating Expense

	Three Months Ended March 31					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 74,102**	**$ 26,190**	**$ 100,292**	$ 45,420	$ 20,468	$ 65,888
Operating expense per boe	**$ 13.72**	**$ 7.08**	**$ 11.02**	$ 15.06	$ 6.31	$ 10.53

Operating expense was $100.3 million ($11.02/boe) for Q1/2019 compared to $65.9 million ($10.53/boe) in Q1/2018. The increase in total operating expense can be attributed to higher production in Q1/2019 relative to Q1/2018 along with a slight increase in per unit operating expense.

In Canada, operating expense was $74.1 million ($13.72/boe) for Q1/2019 compared to $45.4 million ($15.06/boe) for Q1/2018. Total operating expense in Canada has increased with higher production following the closing of the Strategic Combination. Per unit operating costs of $13.72/boe for Q1/2019 decreased from $15.06/boe in Q1/2018. 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 of $26.2 million ($7.08/boe) for Q1/2019 was higher than $20.5 million ($6.31/boe) for Q1/2018. The increase in total operating expense reflects higher U.S. production combined with a weaker Canadian dollar in Q1/2019 compared to Q1/2018. Expressed in U.S. dollars, per unit operating expense for our U.S. properties of US$5.33/boe in Q1/2019 is fairly consistent with US $4.99/boe for Q1/2018.

Operating expense of $11.02/boe for Q1/2019 is consistent with expectations and is at the midpoint of our 2019 annual guidance range of $10.75 - $11.25/boe.

Transportation Expense

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of oil in Canada to pipeline and rail terminals which can vary from period to period depending on hauling distances as we seek to optimize sales prices and trucking rates. The following table compares our transportation expense for the three months ended March 31, 2019 and 2018.

	Three Months Ended March 31					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 13,330**	**$ —**	**$ 13,330**	$ 8,519	$ —	$ 8,519
Transportation expense per boe	**$ 2.47**	**$ —**	**$ 1.46**	$ 2.83	$ —	$ 1.36

Transportation expense was $13.3 million ($1.46/boe) for Q1/2019 compared to $8.5 million ($1.36/boe) for Q1/2018. The increase in transportation expense reflects $5.0 million of additional oil trucking and transportation costs associated with our Viking and Duvernay light oil properties acquired as part of the Strategic Combination. Per unit transportation expense of $1.46/boe was higher than Q1/2018 and above our expectations after pipeline apportionment in Q1/2019 required increased trucking costs as we optimized our crude oil deliveries. We expect per unit transportation expense for the remainder of 2019 to be in line with our annual guidance range of $1.25 - $1.35/boe.

Blending and Other Expense

Blending and other expense primarily includes the cost of blending diluent purchased in order to reduce the viscosity of our heavy oil transported through pipelines 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. Accordingly, our heavy oil sales price realization can fluctuate depending on the quantity and price of blending diluent required to meet pipeline specifications.

Blending and other expense was $16.8 million for Q1/2019 which was relatively consistent with $17.3 million for Q1/2018.

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 months ended March 31, 2019 and 2018.

	Three Months Ended March 31		
($ thousands)	**2019**	2018	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ 17,812**	$ (10,265)	$ 28,077
Natural gas	**966**	424	542
Interest and financing	**36**	—	36
Total	**$ 18,814**	$ (9,841)	$ 28,655
Unrealized financial derivatives gain (loss)			
Crude oil	**$ (51,166)**	$ (17,659)	$ (33,507)
Natural gas	**(1,580)**	(50)	(1,530)
Interest and financing	**(515)**	—	(515)
Total	**$ (53,261)**	$ (17,709)	$ (35,552)
Total financial derivatives gain (loss)			
Crude oil	**$ (33,354)**	$ (27,924)	$ (5,430)
Natural gas	**(614)**	374	(988)
Interest and financing	**(479)**	—	(479)
Total	**$ (34,447)**	$ (27,550)	$ (6,897)

During Q1/2019 we recorded total financial derivative losses of $34.4 million which consisted of realized gains of $18.8 million and unrealized losses of $53.3 million.

Realized financial derivatives gains of $18.8 million for Q1/2019 are primarily a result of the market prices for crude oil settling at levels below those set in our derivative contracts. We recorded realized gains of $1.0 million on our natural gas financial derivatives during Q1/2019. These gains were primarily a result of the NYMEX price index for Q1/2019 averaging less than the average fixed price on our NYMEX contracts in place for the period.

During Q1/2019 we recorded unrealized losses of $53.3 million as the fair value of our financial derivative contracts at March 31, 2019 decreased from a net asset of $79.6 million at December 31, 2018 to a net asset of $26.3 million at March 31, 2019. The decrease in the fair value of our financial derivatives is primarily a result of improved futures pricing for WTI and Brent at March 31, 2019 compared to December 31, 2018 along with the realized gains recorded in Q1/2019.

We had the following commodity financial derivative contracts as at May 2, 2019.

	Period	Volume	Price/Unit[1]	Index
Oil				
Fixed - Sell	Apr 2019 to Jun 2019	2,000 bbl/d	US$62.85/bbl	WTI
Basis Swap	Apr 2019 to Jun 2019	4,000 bbl/d	WTI less US$14.20/bbl	WCS
Basis Swap	Jul 2019 to Sep 2019	4,000 bbl/d	WTI less US$17.38/bbl	WCS
Basis Swap	Oct 2019 to Dec 2019	4,000 bbl/d	WTI less US$20.88/bbl	WCS
Fixed - Sell	Apr 2019 to Dec 2019	3,000 bbl/d	US$61.63/bbl	WTI
3-way option[2]	Apr 2019 to Dec 2019	2,000 bbl/d	US$50.00/US$60.00/US$70.00	WTI
3-way option[2]	Apr 2019 to Dec 2019	1,000 bbl/d	US$55.00/US$65.00/US$72.60	WTI
3-way option[2]	Apr 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$72.50	WTI
3-way option[2]	Apr 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$73.00	WTI
3-way option[2]	Apr 2019 to Dec 2019	2,000 bbl/d	US$57.00/US$67.00/US$73.00	WTI
3-way option[2]	Apr 2019 to Dec 2019	2,000 bbl/d	US$58.00/US$68.00/US$74.00	WTI
3-way option[2]	Apr 2019 to Dec 2019	2,000 bbl/d	US$49.00/US$61.70/US$75.00	WTI
3-way option[2]	Apr 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$69.90/US$75.00	WTI
3-way option[2]	Apr 2019 to Dec 2019	1,000 bbl/d	US$61.00/US$71.00/US$76.00	WTI
3-way option[2]	Apr 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$78.00	WTI
3-way option[2]	Apr 2019 to Dec 2019	1,000 bbl/d	US$55.50/US$65.50/US$75.50	Brent
3-way option[2]	Apr 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$70.00/US$77.55	Brent
3-way option[2]	Apr 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$83.00	Brent
Fixed - Sell[4]	Apr 2019 to Dec 2019	2,000 bbl/d	US$61.45/bbl	WTI
Fixed - Sell[4]	May 2019 to Dec 2019	5,000 bbl/d	US$64.09/bbl	WTI
Basis Swap[4]	Jun 2019 to Dec 2019	4,000 bbl/d	WTI less US$8.00/bbl	MSW
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
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][4]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI
3-way option[2][4]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI
3-way option[2][4]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI
3-way option[2][4]	Jan 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	WTI
Natural Gas				
Fixed - Sell	Apr 2019 to Dec 2019	5,000 mmbtu/d	US$3.15	NYMEX
Fixed - Sell	Apr 2019 to Jun 2019	10,000 mmbtu/d	US$2.79	NYMEX
Fixed - Sell	Jul 2019 to Sep 2019	10,000 mmbtu/d	US$2.79	NYMEX
Fixed - Sell	Oct 2019 to Dec 2019	10,000 mmbtu/d	US$2.88	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) Contracts entered subsequent to March 31, 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.

Baytex has committed to deliver the following volumes of raw bitumen to market on rail.

Period	Volume
Apr 2019 to Oct 2019	1,000 bbl/d
Apr 2019 to Dec 2019	10,000 bbl/d
Jan 2020 to Dec 2020	5,000 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 months ended March 31, 2019 and 2018.

	Three Months Ended March 31					
	2019			2018		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**60,018**	**41,097**	**101,115**	33,505	36,017	69,522
Operating netback:						
Total sales, net of blending and other expense	**$ 45.77**	**$ 51.20**	**$ 47.98**	$ 29.69	$ 55.30	$ 42.96
Less:						
Royalties	**(4.66)**	**(15.18)**	**(8.94)**	(3.76)	(16.51)	(10.36)
Operating expense	**(13.72)**	**(7.08)**	**(11.02)**	(15.06)	(6.31)	(10.53)
Transportation expense	**(2.47)**	**—**	**(1.46)**	(2.83)	—	(1.36)
Operating netback	**$ 24.92**	**$ 28.94**	**$ 26.56**	$ 8.04	$ 32.48	$ 20.71
Realized financial derivatives (loss) gain	**—**	**—**	**2.07**	—	—	(1.57)
Operating netback after financial derivatives	**$ 24.92**	**$ 28.94**	**$ 28.63**	$ 8.04	$ 32.48	$ 19.14

Our operating netback after financial derivatives was $28.63/boe for Q1/2019 which was $9.49/boe higher than $19.14/boe for Q1/2018. The increase was driven by higher realized pricing in Canada which was slightly offset by lower pricing in our U.S operations. We recorded realized gains on financial derivatives of $2.07/boe in Q1/2019 compared to realized losses of $1.57/boe in Q1/2018 which increased our Q1/2019 netback after financial derivatives by $3.64/boe relative to Q1/2018.

In Canada, our operating netback increased to $24.92/boe in Q1/2019 from $8.04/boe in Q1/2018. The increase in our netback was primarily from an increase in our realized sales price per boe during Q1/2019 which was driven by narrower Canadian oil differentials relative to Q1/2018 and from a higher portion of our production coming from light oil after the Strategic Combination. Our operating netback in the U.S. decreased $3.54/boe as our realized sales price decreased with lower benchmark pricing in Q1/2019 compared to Q1/2018.

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 capital on behalf of our working interest partners. G&A expense fluctuates with head office staffing levels and the level of operated capital activity during the period.

The following table summarizes our G&A expense for the three months ended March 31, 2019 and 2018.

	Three Months Ended March 31		
($ thousands except for per boe)	**2019**	2018	Change
Gross general and administrative expense	**$ 15,619**	$ 13,036	$ 2,583
Overhead recoveries	**(1,483)**	(2,028)	545
General and administrative expense	**$ 14,136**	$ 11,008	$ 3,128
General and administrative expense per boe	**$ 1.55**	$ 1.76	$ (0.21)

We reported G&A expense of $14.1 million ($1.55/boe) for Q1/2019 which is $3.1 million higher than $11.0 million ($1.76/boe) for Q1/2018. The increase in G&A expense can be attributed to the additional costs and staff associated with the Strategic Combination. This was partially offset by a $1.1 million reduction associated with a change in accounting for lease contracts. Per unit G&A expense was lower in Q1/2019 relative to Q1/2018 as we were able to realize efficiencies by combining the two organizations.

G&A expense for Q1/2019 is slightly higher than our expectation due to severance costs associated with a reduction in staffing levels and $0.5 million of lease costs we originally expected to by capitalized on adoption IFRS 16. Due to these changes we are increasing our annual guidance for G&A expense to approximately $46 million ($1.30/boe) for 2019.

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 months ended March 31, 2019 and 2018.

	Three Months Ended March 31		
($ thousands except for per boe)	**2019**	2018	Change
Interest on bank loan	**$ 5,412**	$ 2,929	$ 2,483
Interest on long-term notes	**22,602**	21,582	1,020
Interest on lease obligations	**170**	—	170
Cash interest	**28,184**	24,511	3,673
Accretion of debt issue costs	**1,095**	1,191	(96)
Accretion of asset retirement obligations	**3,463**	2,308	1,155
Financing and interest expense	**$ 32,742**	$ 28,010	$ 4,732
Cash interest per boe	**$ 3.10**	$ 3.92	$ (0.82)
Financing and interest expense per boe	**$ 3.60**	$ 4.48	$ (0.88)

Financing and interest expense was $32.7 million for Q1/2019 which is $4.7 million higher than $28.0 million reported for Q1/2018. Interest on our bank loan of $5.4 million in Q1/2019 increased $2.5 million relative to $2.9 million in Q1/2018 due to the increase in loan balances following the assumption of net debt associated with the Strategic Combination. The weighted average interest rate on the credit facilities for Q1/2019 was 4.2% as compared to 4.8% for Q1/2018. The interest reported on our long-term notes was higher in Q1/2019 compared to Q1/2018 as the exchange rate used to convert the reported interest on our U.S. dollar denominated notes was higher in Q1/2019 relative to the same period of 2018. Accretion of asset retirement obligation was higher in Q1/2019 as our asset retirement obligation increased with the Strategic Combination. Q1/2019 cash interest expense of $28.2 million or $3.10/boe was in line with expectations and we are maintaining our 2019 annual guidance of approximately $112 million or $3.23/boe.

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 $1.8 million for Q1/2019 is consistent with $2.0 million for Q1/2018.

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 months ended March 31, 2019 and 2018.

	Three Months Ended March 31		
($ thousands except for per boe)	**2019**	2018	Change
Depletion	**$ 184,844**	$ 107,460	$ 77,384
Depreciation	**510**	829	(319)
Depletion and depreciation	**$ 185,354**	$ 108,289	$ 77,065
Depletion and depreciation per boe	**$ 20.37**	$ 17.31	$ 3.06

Depletion and depreciation expense was $185.4 million ($20.37/boe) for Q1/2019 compared to $108.3 million ($17.31/boe) for Q1/2018. Total depletion and depreciation expense was higher in Q1/2019 due to the Strategic Combination which resulted in a higher depletable base and production relative to Q1/2018. 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 and resulted in the depletion rate of $20.37/boe for Q1/2019 which was $3.06/boe higher than the rate of $17.31/boe for Q1/2018.

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 $5.8 million for Q1/2019 compared to $3.9 million for Q1/2018. SBC expense is higher in Q1/2019 relative to Q1/2018 due to the additional expense 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 operations.

	Three Months Ended March 31		
($ thousands except for exchange rates)	**2019**	2018	Change
Unrealized foreign exchange (gain) loss	**$ (26,941)**	$ 36,046	$ (62,987)
Realized foreign exchange (gain) loss	**(595)**	171	(766)
Foreign exchange (gain) loss	**$ (27,536)**	$ 36,217	$ (63,753)
CAD/USD exchange rates:			
At beginning of period	**1.3646**	1.2518	
At end of period	**1.3360**	1.2901	

We recorded an unrealized foreign exchange gain of $26.9 million for Q1/2019 compared to a loss of $36.0 million for Q1/2018. At March 31, 2019 the Canadian dollar had strengthened relative to the U.S. dollar from a CAD/USD exchange rate of 1.3646 at December 31, 2018 to 1.3360 which resulted in a gain of $26.9 million. In Q1/2018 the Canadian dollar weakened relative to the U.S. dollar at December 31, 2017 and resulted in a loss of $36.0 million as the CAD/USD exchange rate was 1.2901 at March 31, 2018 compared to 1.2518 at 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 gain of $0.6 million for Q1/2019 compared to a loss of $0.2 million for Q1/2018.

Income Taxes

($ thousands)		Three Months Ended March 31 2019		2018		Change
Current income tax expense (recovery)	$	**595**	$	(73)	$	668
Deferred income tax recovery		**(14,485)**		(22,917)		8,432
Total income tax recovery	$	**(13,890)**	$	(22,990)	$	9,100

Current income tax expense was $0.6 million for Q1/2019 compared to a recovery of $0.1 million for Q1/2018. The current income tax expense for Q1/2019 reflects state taxes owing on our U.S. operations.

We recorded a deferred income tax recovery of $14.5 million for Q1/2019 compared to $22.9 million for Q1/2018. The deferred income tax recovery was lower in Q1/2019 as the increase in Canadian taxable income was partially offset by the increase in unrealized financial derivative losses.

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 months ended March 31, 2019 and 2018 are set forth in the following table.

($ thousands)		Three Months Ended March 31 2019		2018		Change
Petroleum and natural gas sales	$	**453,424**	$	286,067	$	167,357
Royalties		**(81,325)**		(64,839)		(16,486)
Revenue, net of royalties		**372,099**		221,228		150,871
Expenses						
Operating		**(100,292)**		(65,888)		(34,404)
Transportation		**(13,330)**		(8,519)		(4,811)
Blending and other		**(16,788)**		(17,290)		502
Operating netback	$	**241,689**	$	129,531	$	112,158
General and administrative		**(14,136)**		(11,008)		(3,128)
Cash financing and interest		**(28,184)**		(24,511)		(3,673)
Realized financial derivatives gain (loss)		**18,814**		(9,841)		28,655
Realized foreign exchange gain (loss)		**595**		(171)		766
Other income		**2,587**		279		2,308
Current income tax (expense) recovery		**(595)**		73		(668)
Payments on onerous contracts		**—**		(97)		97
Adjusted funds flow	$	**220,770**	$	84,255	$	136,515
Exploration and evaluation		**(1,844)**		(2,019)		175
Depletion and depreciation		**(185,354)**		(108,289)		(77,065)
Share based compensation		**(5,843)**		(3,915)		(1,928)
Non-cash financing and accretion		**(4,558)**		(3,499)		(1,059)
Unrealized financial derivatives loss		**(53,261)**		(17,709)		(35,552)
Unrealized foreign exchange gain (loss)		**26,941**		(36,046)		62,987
Gain on disposition of oil and gas properties		**—**		1,486		(1,486)
Deferred income tax recovery		**14,485**		22,917		(8,432)
Payments on onerous contracts		**—**		97		(97)
Net income (loss) for the period	$	**11,336**	$	(62,722)	$	74,058

We generated adjusted funds flow of $220.8 million for Q1/2019, an increase of $136.5 million from adjusted funds flow of $84.3 million reported for Q1/2018. The increase in adjusted funds flow in Q1/2019 was primarily due to higher operating netback which increased $112.2 million from Q1/2018 due to higher commodity prices and production as a result of the Strategic Combination which increased revenues, partially offset by higher royalties, operating and transportation expenses. Hedging gains of $18.8 million recorded in Q1/2019 also contributed to higher adjusted funds flow relative to Q1/2018 when we recorded hedging losses of $9.8 million.

In Q1/2019 we reported net income of $11.3 million compared to a net loss of $62.7 million in Q1/2018. The $136.5 million increase in adjusted funds flow was offset by higher depletion of $77.1 million and higher unrealized losses on our financial derivatives of $36.0 million. We also recorded a foreign exchange gain on our US denominated long-term debt of $26.9 million compared to a loss of $36.0 million during Q1/2018 which increased net income by $63.0 million during the quarter.

Other Comprehensive Income (Loss)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets not recognized in profit or loss. The $47.8 million foreign currency translation loss for Q1/2019 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the strengthening of the Canadian dollar against the U.S. dollar over the same period. The CAD/USD exchange rate was 1.3360 as at March 31, 2019 compared to 1.3646 as at December 31, 2018.

Capital Expenditures

Capital expenditures for the three months ended March 31, 2019 and 2018 are summarized as follows.

	Three Months Ended March 31					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 88,881**	**$ 46,059**	**$ 134,940**	$ 33,543	$ 35,171	$ 68,714
Facilities	**12,940**	**2,662**	**15,602**	12,991	6,838	19,829
Land, seismic and other	**3,049**	**252**	**3,301**	4,991	—	4,991
Total exploration and development	**$ 104,870**	**$ 48,973**	**$ 153,843**	$ 51,525	$ 42,009	$ 93,534
Total acquisitions, net of proceeds from divestitures	**$ —**	**$ —**	**$ —**	$ (2,026)	$ —	$ (2,026)

Exploration and development expenditures were $153.8 million for Q1/2019 compared to $93.5 million for Q1/2018. Higher exploration and development expenditures in Q1/2019 relative to Q1/2018 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 $104.9 million on exploration and development activities in Q1/2019 which is $53.3 million higher than $51.5 million in Q1/2018. Exploration and development expenditures included costs associated with drilling 98 (78.3 net) light oil wells, 1 (1.0 net) heavy oil well and 4 (4.0 net) stratigraphic exploration wells during Q1/2019. Facilities expenditures of $12.9 million in Q1/2019 includes the expansion of our gathering systems to support light oil development in the Viking and Duvernay.

Total U.S. exploration and development expenditures were $49.0 million for Q1/2019, $7.0 million higher than $42.0 million for Q1/2018. Higher exploration and development expenditures in Q1/2019 are primarily a result of increased completion activity on our lands relative to Q1/2018. During Q1/2019 we participated in the drilling of 23 (3.6 net) wells and commenced production from 36 (8.9 net) wells compared to 25 (6.9 net) wells drilled and 27 (5.5 net) wells on production during Q1/2018.

We have narrowed our 2019 annual guidance range and we expect to invest between $575 million and $625 million on exploration and development activities during 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 March 31, 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 growth. At March 31, 2019, net debt was $2,175.2 million, a decrease of $89.9 million from December 31, 2018. The decrease in net debt is primarily a result of adjusted funds flow exceeding exploration and development expenditures for Q1/2019 by $66.9 million. Net debt was also lower at March 31, 2019 due to a strengthening of the Canadian dollar which resulted in a $27.2 million decrease in the reported 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 March 31, 2019, our net debt to adjusted funds flow ratio was 2.8, after adjustment for the Strategic Combination as if the transaction had occurred on the first day of the relevant period, 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 commodity prices and production combined with net debt that was $89.9 million lower at March 31, 2019.

Bank Loan

At March 31, 2019, the principal amount of bank loan and letters of credit outstanding was $566.2 million and we had approximately $502.0 million of undrawn capacity under our credit facilities that total approximately $1.07 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, Baytex amended its 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 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 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 2019).

The weighted average interest rate on the credit facilities for Q1/2019 was 4.2% as compared to 4.8% for Q1/2018.

Financial Covenants

The following table summarizes the financial covenants applicable to the Revolving Facilities and our compliance therewith at March 31, 2019.

Covenant Description	Position as at March 31, 2019	Covenant
Senior Secured Debt[(1)] to Bank EBITDA[(2)] (Maximum Ratio)	**0.64:1.00**	3.50:1.00
Interest Coverage[(3)] (Minimum Ratio)	**8.16:1.00**	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 March 31, 2019, the Company's Senior Secured Debt totaled $566.2 million which includes $550.8 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 March 31, 2019 was $881.3 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 March 31, 2019 were $108.0 million.*

Long-Term Notes

We have four series of long-term notes outstanding that total $1.57 billion as at March 31, 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. As at March 31, 2019, the fixed charge coverage ratio was 8.16:1.00.

On February 17, 2011, we issued US$150 million principal amount of senior unsecured notes bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. These notes are redeemable at our option, in whole or in part, at par from February 17, 2019 to maturity.

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.

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. As of June 1, 2017, the 5.125% Notes are redeemable at our option, in whole or in part, at specified redemption prices. The 5.625% Notes will be redeemable at our option, in whole or in part, commencing on June 1, 2019 at specified redemption prices.

Shareholders’ Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the three months ended March 31, 2019, we issued 1.8 million common shares pursuant to our share-based compensation program. As at May 2, 2019, we had 556.5 million common shares issued and outstanding and no preferred shares issued and outstanding.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact our adjusted funds flow in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of March 31, 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	**$ 236,703**	$ 236,703	$ —	$ —	$ —
Bank loan[1] [2]	**550,751**	—	550,751	—	—
Long-term notes[2]	**1,569,153**	—	734,773	300,000	534,380
Interest on long-term notes[3]	**306,104**	90,847	143,989	66,162	5,106
Lease agreements	**17,516**	6,325	10,130	1,061	—
Processing agreements	**44,569**	10,330	14,101	8,948	11,190
Transportation agreements	**107,970**	16,316	40,616	17,861	33,177
Total	**$ 2,832,766**	$ 360,521	$ 1,494,360	$ 394,032	$ 583,853

(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 bank loan as interest payments on bank loans fluctuate based on interest rate and bank loan balance.

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

	2019	2018				2017		
($ thousands, except per common share amounts)	**Q1**	Q4	Q3	Q2	Q1	Q4	Q3	Q2
Petroleum and natural gas sales	**453,424**	358,437	436,761	347,605	286,067	303,163	258,620	277,536
Net income (loss)	**11,336**	(231,238)	27,412	(58,761)	(62,722)	76,038	(9,228)	9,268
Per common share - basic	**0.02**	(0.42)	0.07	(0.25)	(0.27)	0.32	(0.04)	0.04
Per common share - diluted	**0.02**	(0.42)	0.07	(0.25)	(0.27)	0.32	(0.04)	0.04
Adjusted funds flow	**220,770**	110,828	171,210	106,690	84,255	105,796	77,340	83,136
Per common share - basic	**0.40**	0.20	0.46	0.45	0.36	0.45	0.33	0.35
Per common share - diluted	**0.40**	0.20	0.45	0.45	0.36	0.44	0.33	0.35
Exploration and development	**153,843**	184,162	139,195	78,830	93,534	90,156	61,544	78,007
Canada	**104,870**	125,507	94,477	30,608	51,525	41,864	14,487	18,439
U.S.	**48,973**	58,655	44,718	48,222	42,009	48,292	47,057	59,568
Acquisitions, net of divestitures	**—**	183	46	(21)	(2,026)	(3,937)	(7,436)	5,226
Net debt	**2,175,241**	2,265,167	2,112,090	1,784,835	1,783,379	1,734,284	1,748,805	1,819,387
Total assets	**6,359,157**	6,377,198	6,491,303	4,476,906	4,433,074	4,372,111	4,353,637	4,582,049
Common shares outstanding	**555,872**	554,060	553,950	236,662	236,578	235,451	235,451	234,204
Daily production								
Total production (boe/d)	**101,115**	98,890	82,412	70,664	69,522	69,556	69,310	72,812
Canada (boe/d)	**60,018**	60,453	45,214	34,042	33,505	32,194	34,560	34,284
U.S. (boe/d)	**41,097**	38,437	37,198	36,622	36,017	37,362	34,750	38,528
Benchmark prices								
WTI oil (US$/bbl)	**54.90**	58.81	69.50	67.88	62.87	55.40	48.20	48.28
WCS heavy (US$/bbl)	**56.64**	19.39	47.25	48.61	38.59	43.14	38.26	37.16
CAD/USD avg exchange rate	**1.3293**	1.3215	1.307	1.2911	1.2651	1.2717	1.2524	1.3447
AECO gas ($/mcf)	**1.94**	1.94	1.35	1.03	1.85	1.96	2.04	2.77
NYMEX gas (US$/mmbtu)	**3.15**	3.64	2.90	2.80	3.00	2.93	3.00	3.18
Sales price ($/boe)	**47.98**	37.89	55.03	51.22	42.96	44.75	38.04	39.41
Royalties ($/boe)	**(8.94)**	(8.77)	(12.13)	(12.01)	(10.36)	(10.86)	(8.65)	(9.06)
Operating expense ($/boe)	**(11.02)**	(10.76)	(10.25)	(10.91)	(10.53)	(10.91)	(10.10)	(10.70)
Transportation expense ($/boe)	**(1.46)**	(1.21)	(1.26)	(1.22)	(1.36)	(1.20)	(1.46)	(1.35)
Operating netback ($/boe)	**26.56**	17.15	31.39	27.08	20.71	21.78	17.83	18.30
Financial derivatives gain (loss) ($/boe)	**2.07**	(0.34)	(4.07)	(4.57)	(1.57)	0.30	0.44	0.40
Operating netback after financial derivatives ($/boe)	**28.63**	16.81	27.32	22.51	19.14	22.08	18.27	18.70

In Q1/2019 we reported our strongest operating and financial results of the eight most recent quarters. Production has increased from 72,812 boe/d during Q2/2017 to 101,115 boe/d in Q1/2019 as a result of the Strategic Combination along with our successful development programs in the U.S. and Canada. Improved well productivity from enhanced completion techniques contributed to the increase in daily production in the U.S. In Canada, exploration and development activity increased in 2018. The increased level of activity along with the Strategic Combination in Q3/2018 has increased production from Q2/2017 into Q1/2019. Compliance with OPEC's production quotas and increased global demand for crude oil resulted in the WTI benchmark gradually increasing from US $48.28/bbl in Q2/2017 to US$69.50/bbl during Q3/2018 before global geopolitical factors caused a decline to US$54.90/bbl in Q1/2019. A narrowing of Canadian oil differentials and improved light oil price realizations due to the Strategic Combination resulted in operating netback after financial derivatives of $28.63/boe in Q1/2019. 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 and increased through Q3/2018 with higher production due to strong well performance along with the Strategic Combination. The increase in production and operating netback after financial derivatives resulted in adjusted funds flow of $220.8 million in Q1/2019 which is $137.6 million higher than $83.1 million reported in Q2/2017.

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 $1,819.4 million at Q2/2017 to $2,175.2 million at Q1/2019 primarily due to the additional net debt of $363.6 million assumed in conjunction with the Strategic Combination in Q3/2018.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at March 31, 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 three months ended March 31, 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 a $18.0 million increase to right-of-use assets ("lease assets"), a $2.0 million reduction of onerous contracts and an $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 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 lease 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.

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

	Three Months Ended March 31	
($ thousands)	**2019**	2018
Cash flow from operating activities	**$ 157,365**	$ 87,612
Change in non-cash working capital	**58,477**	(6,620)
Asset retirement obligations settled	**4,928**	3,263
Adjusted funds flow	**$ 220,770**	$ 84,255

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 March 31	
($ thousands)	**2019**	2018
Cash flow used in investing activities	**$ 187,588**	$ 83,696
Change in non-cash working capital	**(33,680)**	7,812
Proceeds from dispositions	**—**	2,213
Property acquisitions	**—**	(187)
Additions to other plant and equipment	**(65)**	—
Exploration and development expenditures	**$ 153,843**	$ 93,534

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 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 liquidity or repayment obligation.

The following table summarizes our calculation of net debt.

($ thousands)	**March 31, 2019**	December 31, 2018
Bank loan(1)	**$ 550,751**	$ 522,294
Long-term notes(1)	**1,569,153**	1,596,323
Trade and other payables	**236,703**	258,114
Trade and other receivables	**(181,366)**	(111,564)
Net debt	**$ 2,175,241**	$ 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 March 31	
($ thousands)	**2019**	2018
Petroleum and natural gas sales	**$ 453,424**	$ 286,067
Blending and other expense	**(16,788)**	(17,290)
Total sales, net of blending and other expense	**436,636**	268,777
Royalties	**(81,325)**	(64,839)
Operating expense	**(100,292)**	(65,888)
Transportation expense	**(13,330)**	(8,519)
Operating netback	**241,689**	129,531
Realized financial derivative gain (loss)	**18,814**	(9,841)
Operating netback after realized financial derivatives	**$ 260,503**	$ 119,690

Bank EBITDA

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

	Three Months Ended March 31	
($ thousands)	**2019**	2018
Net income (loss)	**$ 11,336**	$ (62,722)
Plus:		
Financing and interest	**32,742**	28,010
Unrealized foreign exchange (gain) loss	**(26,941)**	36,046
Unrealized financial derivatives loss	**53,261**	17,709
Current income tax expense (recovery)	**595**	(73)
Deferred income tax recovery	**(14,485)**	(22,917)
Depletion and depreciation	**185,354**	108,289
Gain loss on disposition of oil and gas properties	**—**	(1,486)
Payments on lease obligations	**(1,389)**	—
Non-cash items[1]	**7,687**	5,934
Bank EBITDA	**$ 248,160**	$ 108,790

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

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended March 31, 2019, except for the matter described below.

On August 22, 2018, Baytex completed the acquisition of Raging River, a publicly traded oil and gas company that was listed on the Toronto Stock Exchange. Raging River's operations have been included in the consolidated financial statements of Baytex since August 22, 2018. However, Baytex has not had sufficient time to appropriately assess the disclosure controls and procedures and internal controls over financial reporting previously used by Raging River and integrate them with those of Baytex. In addition, Raging River was not subject to the Sarbanes-Oxley Act of 2002 and, therefore, was not required to have its external auditors audit the effectiveness of its internal control over financial reporting. As a result, the certifying officers have limited the scope of their design of disclosure controls and procedures and internal controls over financial reporting to exclude controls, policies and procedures of Raging River (as permitted by applicable securities laws in Canada and the U.S.). Baytex has a program in place to complete its assessment of the controls, policies and procedures of the acquired operations by August 22, 2019.

During the three months ended March 31, 2019, the assets previously held by Raging River contributed revenues net of royalties of $123.1 million. At March 31, 2019, total assets of $2.1 billion were associated with the acquired entity.

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 business strategies, plans and objectives; the percentage of production from the Raging River properties that is high operating netback light oil; our capital budget and expected average daily production for 2019; and our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2019; that we expect production to decline in Q2/2019; 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 and our plan to complete an assessment of the controls, policies and procedures associated with Raging River by August 22, 2019.*

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)

		As at	
	Notes	**March 31, 2019**	December 31, 2018
ASSETS			
Current assets			
Trade and other receivables	18	**$ 181,366**	$ 111,564
Financial derivatives	18	**27,569**	79,582
		208,935	191,146
Non-current assets			
Exploration and evaluation assets	5	**349,768**	358,935
Oil and gas properties	6	**5,775,238**	5,817,889
Other plant and equipment		**8,783**	9,228
Lease assets	3	**16,433**	—
		$ 6,359,157	$ 6,377,198
LIABILITIES			
Current liabilities			
Trade and other payables	18	**$ 236,703**	$ 258,114
Financial derivatives	18	**127**	—
Lease obligations	3, 9	**5,784**	—
Onerous contracts	3	**—**	1,986
		242,614	260,100
Non-current liabilities			
Financial derivatives	18	**1,121**	—
Bank loan	7	**549,503**	520,700
Long-term notes	8	**1,557,058**	1,583,240
Lease obligations	3, 9	**10,786**	—
Asset retirement obligations	10	**679,759**	646,898
Deferred income tax liability		**293,507**	310,836
		3,334,348	3,321,774
SHAREHOLDERS' EQUITY			
Shareholders' capital	11	**5,709,162**	5,701,516
Contributed surplus		**17,334**	19,137
Accumulated other comprehensive income		**620,080**	667,874
Deficit		**(3,321,767)**	(3,333,103)
		3,024,809	3,055,424
		$ 6,359,157	$ 6,377,198

Subsequent event (note 7)

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 March 31	
	Notes	**2019**	2018
Revenue, net of royalties			
Petroleum and natural gas sales	12	**$ 453,424**	$ 286,067
Royalties		**(81,325)**	(64,839)
		372,099	221,228
Expenses			
Operating		**100,292**	65,888
Transportation		**13,330**	8,519
Blending and other		**16,788**	17,290
General and administrative		**14,136**	11,008
Exploration and evaluation	5	**1,844**	2,019
Depletion and depreciation		**185,354**	108,289
Share-based compensation	13	**5,843**	3,915
Financing and interest	16	**32,742**	28,010
Financial derivatives loss	18	**34,447**	27,550
Foreign exchange (gain) loss	17	**(27,536)**	36,217
Gain on disposition of oil and gas properties		**—**	(1,486)
Other income		**(2,587)**	(279)
		374,653	306,940
Net loss before income taxes		**(2,554)**	(85,712)
Income tax expense (recovery)	15		
Current income tax expense (recovery)		**595**	(73)
Deferred income tax recovery		**(14,485)**	(22,917)
		(13,890)	(22,990)
Net income (loss) attributable to shareholders		**$ 11,336**	$ (62,722)
Other comprehensive income (loss)			
Foreign currency translation adjustment		**(47,794)**	72,322
Comprehensive income (loss)		**$ (36,458)**	$ 9,600
Net income (loss) per common share	14		
Basic		**$ 0.02**	$ (0.27)
Diluted		**$ 0.02**	$ (0.27)
Weighted average common shares (000's)	14		
Basic		**555,438**	236,315
Diluted		**558,732**	236,315

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**
Vesting of share awards	8,325	(8,325)	—	—	**—**
Share-based compensation	—	3,915	—	—	**3,915**
Comprehensive income (loss) for the period	—	—	72,322	(62,722)	**9,600**
Balance at March 31, 2018	$ 4,451,901	$ 11,589	$ 535,426	$ (3,070,516)	**$ 1,928,400**
Balance at December 31, 2018	$ 5,701,516	$ 19,137	$ 667,874	$ (3,333,103)	**$ 3,055,424**
Vesting of share awards	7,646	(7,646)	—	—	**—**
Share-based compensation	—	5,843	—	—	**5,843**
Comprehensive income (loss) for the period	—	—	(47,794)	11,336	**(36,458)**
Balance at March 31, 2019	$ 5,709,162	$ 17,334	$ 620,080	$ (3,321,767)	**$ 3,024,809**

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 March 31	
	Notes	**2019**	2018
CASH PROVIDED BY (USED IN):			
Operating activities			
Net income (loss) for the period		**$ 11,336**	$ (62,722)
Adjustments for:			
Share-based compensation	13	**5,843**	3,915
Unrealized foreign exchange (gain) loss	17	**(26,941)**	36,046
Exploration and evaluation	5	**1,844**	2,019
Depletion and depreciation		**185,354**	108,289
Non-cash financing and accretion	16	**4,558**	3,499
Unrealized financial derivatives loss	18	**53,261**	17,709
Gain on disposition of capital properties		**—**	(1,486)
Deferred income tax recovery		**(14,485)**	(22,917)
Payments on onerous contracts		**—**	(97)
Asset retirement obligations settled	10	**(4,928)**	(3,263)
Change in non-cash working capital		**(58,477)**	6,620
		157,365	87,612
Financing activities			
Increase (decrease) in bank loan		**31,612**	(3,916)
Payments on lease obligations	9	**(1,389)**	—
		30,223	(3,916)
Investing activities			
Additions to exploration and evaluation assets	5	**(1,125)**	(1,287)
Additions to oil and gas properties	6	**(152,718)**	(92,247)
Additions to other plant and equipment		**(65)**	—
Property acquisitions		**—**	(187)
Proceeds from disposition of capital properties		**—**	2,213
Change in non-cash working capital		**(33,680)**	7,812
		(187,588)	(83,696)
Change in cash		**—**	—
Cash, beginning of period		**—**	—
Cash, end of period		**$ —**	$ —
Supplementary information			
Interest paid		**$ 22,035**	$ 18,876
Income taxes paid		**$ —**	$ —

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 unaudited 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 audited 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 May 2, 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 a $18.0 million increase to right-of-use assets ("lease assets"), a $2.0 million reduction of onerous contracts and an $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 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 lease 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 March 31	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 264,039**	$ 106,814	**$ 189,385**	$ 179,253	**$ —**	$ —	**$ 453,424**	$ 286,067
Royalties	**(25,184)**	(11,334)	**(56,141)**	(53,505)	**—**	—	**(81,325)**	(64,839)
	238,855	95,480	**133,244**	125,748	**—**	—	**372,099**	221,228
Expenses								
Operating	**74,102**	45,420	**26,190**	20,468	**—**	—	**100,292**	65,888
Transportation	**13,330**	8,519	**—**	—	**—**	—	**13,330**	8,519
Blending and other	**16,788**	17,290	**—**	—	**—**	—	**16,788**	17,290
General and administrative	**—**	—	**—**	—	**14,136**	11,008	**14,136**	11,008
Exploration and evaluation	**1,844**	2,019	**—**	—	**—**	—	**1,844**	2,019
Depletion and depreciation	**115,020**	46,340	**69,824**	61,120	**510**	829	**185,354**	108,289
Share-based compensation	**—**	—	**—**	—	**5,843**	3,915	**5,843**	3,915
Financing and interest	**—**	—	**—**	—	**32,742**	28,010	**32,742**	28,010
Financial derivatives loss	**—**	—	**—**	—	**34,447**	27,550	**34,447**	27,550
Foreign exchange (gain) loss	**—**	—	**—**	—	**(27,536)**	36,217	**(27,536)**	36,217
Gain on disposition of oil and gas properties	**—**	(1,486)	**—**	—	**—**	—	**—**	(1,486)
Other income	**—**	—	**—**	—	**(2,587)**	(279)	**(2,587)**	(279)
	221,084	118,102	**96,014**	81,588	**57,555**	107,250	**374,653**	306,940
Net income (loss) before income taxes	**17,771**	(22,622)	**37,230**	44,160	**(57,555)**	(107,250)	**(2,554)**	(85,712)
Income tax expense (recovery)								
Current income tax expense (recovery)	**—**	—	**595**	(73)	**—**	—	**595**	(73)
Deferred income tax expense (recovery)	**4,248**	(6,107)	**2,694**	2,239	**(21,427)**	(19,049)	**(14,485)**	(22,917)
	4,248	(6,107)	**3,289**	2,166	**(21,427)**	(19,049)	**(13,890)**	(22,990)
Net income (loss)	**$ 13,523**	$ (16,515)	**$ 33,941**	$ 41,994	**$ (36,128)**	$ (88,201)	**$ 11,336**	$ (62,722)
Total oil and natural gas capital expenditures[(1)]	**$ 104,870**	$ 49,499	**$ 48,973**	$ 42,009	**$ —**	$ —	**$ 153,843**	$ 91,508

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

As at	**March 31, 2019**	December 31, 2018
Canadian assets	**$ 3,806,030**	$ 3,739,029
U.S. assets	**2,544,344**	2,628,941
Corporate assets	**8,783**	9,228
Total consolidated assets	**$ 6,359,157**	$ 6,377,198

5. EXPLORATION AND EVALUATION ASSETS

		March 31, 2019		December 31, 2018
Balance, beginning of period	**$**	**358,935**	$	272,974
Capital expenditures		**1,125**		10,567
Corporate acquisition		**—**		97,858
Property acquisitions		**—**		514
Divestitures		**—**		(1,021)
Exploration and evaluation expense		**(1,844)**		(21,729)
Transfer to oil and gas properties		**(5,275)**		(13,866)
Foreign currency translation		**(3,173)**		13,638
Balance, end of period	**$**	**349,768**	$	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		152,718		—		152,718
Transfers from exploration and evaluation assets		5,275		—		5,275
Change in asset retirement obligations (note 10)		35,218		—		35,218
Foreign currency translation		(82,036)		31,496		(50,540)
Depletion		—		(185,322)		(185,322)
Balance, March 31, 2019	**$**	**10,855,708**	**$**	**(5,080,470)**	**$**	**5,775,238**

7. BANK LOAN

		March 31, 2019		December 31, 2018
Bank loan - U.S. dollar denominated(1)	**$**	**78,835**	$	122,388
Bank loan - Canadian dollar denominated		**471,916**		399,906
Bank loan - principal		**550,751**		522,294
Unamortized debt issuance costs		**(1,248)**		(1,594)
Bank loan	**$**	**549,503**	$	520,700

(1) U.S. dollar denominated bank loan balance was US$59.0 million as at March 31, 2019 (December 31, 2018 - US$89.7 million).

Baytex has credit facilities that 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, 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 March 31, 2019, Baytex had $15.4 million of outstanding letters of credit (December 31, 2018 - $14.6 million) under the credit facilities.

At March 31, 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 March 31, 2019.

Covenant Description	**Position as at March 31, 2019**	**Covenant**
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.64:1.00**	**3.50:1.00**
Interest Coverage(3) (Minimum Ratio)	**8.16:1.00**	**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 March 31, 2019, the Company's Senior Secured Debt totaled $566.2 million which includes $550.8 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 March 31, 2019 was $881.3 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 March 31, 2019 were $108.0 million.

8. LONG-TERM NOTES

	March 31, 2019	December 31, 2018
6.75% notes (US$150,000 – principal) due February 17, 2021	**$ 200,393**	$ 204,683
5.125% notes (US$400,000 – principal) due June 1, 2021	**534,380**	545,820
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	**300,000**	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	**534,380**	545,820
Total long-term notes - principal	**1,569,153**	1,596,323
Unamortized debt issuance costs	**(12,095)**	(13,083)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,557,058**	$ 1,583,240

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 March 31, 2019, the fixed charge coverage ratio was 8.16:1.00.

9. LEASE OBLIGATIONS

Baytex had the following future commitments associated with its lease obligations at March 31, 2019.

	March 31, 2019
Less than 1 year	$ 6,325
1 - 3 years	10,130
3 - 5 years	1,061
After 5 years	—
Total lease payments	17,516
Amounts representing interest over the term of the lease	(946)
Present value of net lease payments	16,570
Less current portion of lease obligations	5,784
Non-current portion of lease obligations	$ 10,786

For the three months ended March 31, 2019, the Company recorded interest of $0.2 million and payments of $1.4 million related to its lease obligations.

10. ASSET RETIREMENT OBLIGATIONS

	March 31, 2019	December 31, 2018
Balance, beginning of period	$ 646,898	$ 368,995
Liabilities incurred	7,471	12,537
Liabilities settled	(4,928)	(14,035)
Liabilities assumed from corporate acquisition	—	39,960
Liabilities acquired from property acquisitions	—	132
Liabilities divested	—	(580)
Accretion (note 16)	3,463	10,914
Change in estimate	—	33,453
Changes in discount rates and inflation rates(1)	27,747	192,672
Foreign currency translation	(892)	2,850
Balance, end of period	$ 679,759	$ 646,898

(1) The discount and inflation rates at March 31, 2019 were 2.00%, 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 March 31, 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**
Transfer from contributed surplus on vesting and conversion 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**
Transfer from contributed surplus on vesting and conversion of share awards	1,812	7,646
Balance, March 31, 2019	**555,872**	**$ 5,709,162**

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 March 31					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 132,368**	**$ 148,916**	**$ 281,284**	$ 4,851	$ 144,607	$ 149,458
Heavy oil	**117,686**	**—**	**117,686**	91,883	—	91,883
NGL	**3,441**	**20,802**	**24,243**	3,356	18,178	21,534
Natural gas sales	**10,544**	**19,667**	**30,211**	6,724	16,468	23,192
Total petroleum and natural gas sales	**$ 264,039**	**$ 189,385**	**$ 453,424**	$ 106,814	$ 179,253	$ 286,067

Included in accounts receivable at March 31, 2019 is $157.1 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 $5.8 million for the three months ended March 31, 2019 ($3.9 million for the three months ended March 31, 2018).

The weighted average fair value of share awards granted was $2.65 per restricted and performance award for the three months ended March 31, 2019 ($4.17 per restricted and performance award for the three months ended March 31, 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	3,074	3,124	6,198
Vested and converted to common shares	(910)	(902)	(1,812)
Forfeited	(50)	(113)	(163)
Balance, March 31, 2019	**5,357**	**5,382**	**10,739**

(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	(394)	5.91
Balance, March 31, 2019	**4,471**	**$ 6.77**

	Options Outstanding			**Options Exercisable**	
Exercise price	Number outstanding at March 31, 2019 (000s)	Weighted average remaining life (years)	Weighted average exercise price	Number exercisable at March 31, 2019 (000s)	Weighted average exercise price
$5.00 - $7.00	3,031	1.16	$ 6.33	2,001	$ 6.42
$7.01 - $9.00	1,440	0.80	7.68	960	7.68
Total	**4,471**	**1.04**	**$ 6.77**	**2,961**	**$ 6.83**

14. NET INCOME (LOSS) PER SHARE

Baytex calculates basic income per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards 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 March 31					
	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	**$ 11,336**	**555,438**	**$ 0.02**	$ (62,722)	236,315	$ (0.27)
Dilutive effect of share awards	**—**	**3,294**	**—**	—	—	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net income (loss) - diluted	**$ 11,336**	**558,732**	**$ 0.02**	$ (62,722)	236,315	$ (0.27)

For the three months ended March 31, 2019, no share awards were considered to be anti-dilutive (2018 - 6.7 million). For the three months ended March 31, 2019, 4.5 million share options were excluded from the calculation of diluted earnings per share as they were determined to be anti-dilutive. There were no share options outstanding at March 31, 2018.

15. INCOME TAXES

The provision for income taxes has been computed as follows:

	Three Months Ended March 31	
	2019	2018
Net loss before income taxes	**$ (2,554)**	$ (85,712)
Expected income taxes at the statutory rate of 27.00% (2018 – 27.00%)	**(690)**	(23,142)
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	**1,578**	967
Non-taxable portion of foreign exchange loss (gain)	**(3,674)**	4,912
Effect of rate adjustments for foreign jurisdictions	**(7,321)**	(9,245)
Effect of change in deferred tax benefit not recognized(1)	**(3,674)**	4,912
Adjustments and assessments	**(109)**	(1,394)
Income tax recovery	**$ (13,890)**	$ (22,990)

(1) A deferred income tax asset has not been recognized for allowable capital losses of $126 million related to the unrealized foreign exchange losses arising from the translation of U.S. dollar denominated long-term notes (December 31, 2018 - $139 million).

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 March 31	
	2019	2018
Interest on bank loan	**$ 5,412**	$ 2,929
Interest on long-term notes	**22,602**	21,582
Interest on lease obligations	**170**	—
Non-cash financing	**1,095**	1,191
Accretion on asset retirement obligations (note 10)	**3,463**	2,308
Financing and interest	**$ 32,742**	$ 28,010

17. FOREIGN EXCHANGE

	Three Months Ended March 31	
	2019	2018
Unrealized foreign exchange (gain) loss	**$ (26,941)**	$ 36,046
Realized foreign exchange (gain) loss	**(595)**	171
Foreign exchange (gain) loss	**$ (27,536)**	$ 36,217

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 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:

	March 31, 2019		December 31, 2018		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL(1)					
Financial derivatives	**$ 27,569**	**$ 27,569**	$ 79,582	$ 79,582	Level 2
Total	**$ 27,569**	**$ 27,569**	$ 79,582	$ 79,582	
Financial assets at amortized cost					
Trade and other receivables	**$ 181,366**	**$ 181,366**	$ 111,564	$ 111,564	—
Total	**$ 181,366**	**$ 181,366**	$ 111,564	$ 111,564	
Financial Liabilities					
FVTPL(1)					
Financial derivatives	**$ (1,248)**	**$ (1,248)**	$ —	$ —	Level 2
Total	**$ (1,248)**	**$ (1,248)**	$ —	$ —	
Financial liabilities at amortized cost					
Trade and other payables	**$ (236,703)**	**$ (236,703)**	$ (258,114)	$ (258,114)	—
Bank loan	**(549,503)**	**(550,751)**	(520,700)	(522,294)	—
Long-term notes	**(1,557,058)**	**(1,524,243)**	(1,583,240)	(1,492,363)	Level 1
Lease obligations	**(16,570)**	**(16,570)**	—	—	—
Total	**$ (2,359,834)**	**$ (2,328,267)**	$ (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 three months ended March 31, 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	
	March 31, 2019	December 31, 2018	**March 31, 2019**	December 31, 2018
U.S. dollar denominated	**US$25,520**	US$80,857	**US$968,461**	US$963,351

Interest Rate Risk

Interest Rate Swaps

Baytex had the following interest rate swaps outstanding as of May 2, 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	$ (0.1)
Total					**$ (0.1)**
Current liability					(0.1)

(1) Canadian Dollar Offered Rate.

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of May 2, 2019:

	Period	Volume	Price/Unit[1]	Index		Fair Value[2] *($ millions)*
Oil						
Fixed - Sell	Apr 2019 to Jun 2019	2,000 bbl/d	US$62.85/bbl	WTI	$	0.8
Basis Swap	Apr 2019 to Jun 2019	4,000 bbl/d	WTI less US$14.20/bbl	WCS	$	(1.5)
Basis Swap	Jul 2019 to Sep 2019	4,000 bbl/d	WTI less US$17.38/bbl	WCS	$	(1.2)
Basis Swap	Oct 2019 to Dec 2019	4,000 bbl/d	WTI less US$20.88/bbl	WCS	$	(0.2)
Fixed - Sell	Apr 2019 to Dec 2019	3,000 bbl/d	US$61.63/bbl	WTI	$	1.4
3-way option[3]	Apr 2019 to Dec 2019	2,000 bbl/d	US$50.00/US$60.00/US$70.00	WTI	$	1.4
3-way option[3]	Apr 2019 to Dec 2019	1,000 bbl/d	US$55.00/US$65.00/US$72.60	WTI	$	1.5
3-way option[3]	Apr 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$72.50	WTI	$	1.7
3-way option[3]	Apr 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$73.00	WTI	$	2.0
3-way option[3]	Apr 2019 to Dec 2019	2,000 bbl/d	US$57.00/US$67.00/US$73.00	WTI	$	3.7
3-way option[3]	Apr 2019 to Dec 2019	2,000 bbl/d	US$58.00/US$68.00/US$74.00	WTI	$	4.7
3-way option[3]	Apr 2019 to Dec 2019	2,000 bbl/d	US$49.00/US$61.70/US$75.00	WTI	$	2.3
3-way option[3]	Apr 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$69.90/US$75.00	WTI	$	2.4
3-way option[3]	Apr 2019 to Dec 2019	1,000 bbl/d	US$61.00/US$71.00/US$76.00	WTI	$	3.0
3-way option[3]	Apr 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$78.00	WTI	$	2.8
3-way option[3]	Apr 2019 to Dec 2019	1,000 bbl/d	US$55.50/US$65.50/US$75.50	Brent	$	0.5
3-way option[3]	Apr 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$70.00/US$77.55	Brent	$	1.2
3-way option[3]	Apr 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$83.00	Brent	$	1.8
Fixed - Sell[5]	Apr 2019 to Dec 2019	2,000 bbl/d	US$61.45/bbl	WTI	$	—
Fixed - Sell[5]	May 2019 to Dec 2019	5,000 bbl/d	US$64.09/bbl	WTI	$	—
Basis Swap[5]	Jun 2019 to Dec 2019	4,000 bbl/d	WTI less US$8.00/bbl	MSW	$	—
Swaption[4]	Jan 2020 to Dec 2020	1,000 bbl/d	US$62.50/bbl	WTI	$	(1.4)
Swaption[4]	Jan 2020 to Dec 2020	1,000 bbl/d	US$63.20/bbl	WTI	$	(1.2)
3-way option[3]	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI	$	(0.1)
3-way option[3]	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI	$	—
3-way option[3]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI	$	0.2
3-way option[3][5]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI	$	—
3-way option[3][5]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI	$	—
3-way option[3][5]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI	$	—
3-way option[3][5]	Jan 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	WTI	$	—
Natural Gas						
Fixed - Sell	Apr 2019 to Dec 2019	5,000 mmbtu/d	US$3.15	NYMEX	$	0.6
Fixed - Sell	Apr 2019 to Jun 2019	10,000 mmbtu/d	US$2.79	NYMEX	$	0.1
Fixed - Sell	Jul 2019 to Sep 2019	10,000 mmbtu/d	US$2.79	NYMEX	$	—
Fixed - Sell	Oct 2019 to Dec 2019	10,000 mmbtu/d	US$2.88	NYMEX	$	—
Total					**$**	**26.5**
Current asset						27.6
Non-current liability						(1.1)

(1) Based on the weighted average price per unit for the period.
(2) Fair values as at March 31, 2019. Contracts entered subsequent to March 31, 2019 have no fair value assigned.
(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) Contracts entered subsequent to March 31, 2019.

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

	Three Months Ended March 31	
	2019	2018
Realized financial derivatives (gain) loss	**$ (18,814)**	$ 9,841
Unrealized financial derivatives loss	**53,261**	17,709
Financial derivatives loss	**$ 34,447**	$ 27,550

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 May 2, 2019, Baytex had committed to deliver the following volumes of raw bitumen to market on rail:

Period	Volume
Apr 2019 to Oct 2019	1,000 bbl/d
Apr 2019 to Dec 2019	10,000 bbl/d
Jan 2020 to Dec 2020	5,000 bbl/d

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
GAAP	Generally Accepted Accounting Principles
GJ	gigajoule
GJ/d	gigajoule per day
IFRS	International Financial Reporting Standards
LIBOR	London Interbank Offered Rate
LLS	Louisiana Light Sweet
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmbtu	million British Thermal Units
mmbtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

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Chairman of the Board

Edward D. LaFehr
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

Gregory K. Melchin (1)(4)
Director

Kevin D. Olson (1)(2)
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

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BANKERS

Bank of Nova Scotia
ATB Financial
Bank of Montreal
Barclays Bank plc
Canadian Imperial Bank of Commerce
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Export Development Canada
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Royal Bank of Canada
The Toronto-Dominion Bank
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President and Chief Executive Officer

Rodney D. Gray
Executive Vice President and
Chief Financial Officer

Jason J. Jaskela
Executive Vice President and
Chief Operating Officer

Brian G. Ector
Vice President, Capital Markets

Kendall D. Arthur
Vice President, Heavy Oil

Jonathan L. Grimwood
Vice President, Exploration

Chad L. Kalmakoff
Vice President, Finance

M. Scott Lovett
Vice President, Corporate Development

Chad E. Lundberg
Vice President, Viking Business Unit

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