BAYTEX
ENERGY CORP.

Q2 REPORT / 2019

PRESS RELEASE

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

Our strong operating performance continues, with our Eagle Ford, Viking and heavy oil assets each delivering robust production and free cash flow. Given our year-to-date results, we are tightening our 2019 production guidance range to 96,000 to 97,000 boe/d (previously 95,000 to 97,000 boe/d) and lowering our budgeted exploration and development capital expenditure range to $550 to $600 million (previously $575 to $625 million). We generated a record level of free cash flow (approximately $200 million) in the first half of the year, which will allow us to redeem our US$150 million senior unsecured notes during the third quarter.

In addition, we are pleased to announce further exploration success in the East Duvernay shale with our (14-31) well brought on-stream June 27. The well has generated a 30-day initial production rate of 1,360 boe/d (76% liquids). This successful result in conjunction with a reduction in drilling and completion capital to approximately $7.0 million per well has solidified Pembina as a highly prospective region of the East Duvernay shale, in which we have a dominant land position of 268 net sections.

Q2/2019 Highlights

- Generated production of 98,402 boe/d (82% oil and NGL), exceeding the high end of our guidance.
- Delivered adjusted funds flow of $236 million ($0.42 per basic share), a 7% increase compared to $221 million ($0.40 per basic share) in Q1/2019.
- Reduced net debt by $147 million during the quarter ($236 million year-to-date) as adjusted funds flow exceeded capital expenditures and the Canadian dollar strengthened relative to the U.S. dollar.
- Realized an operating netback (inclusive of hedging) of $30.72/boe, our highest level since 2014.
- Eagle Ford production remained strong at 39,822 boe/d reflective of continued impressive well performance. We established average 30-day initial production rates of approximately 2,045 boe/d per well from 29 (5.0 net) wells that commenced production during the quarter.
- Production in Canada averaged 58,580 boe/d, down 2% (compared to Q1/2019) reflective of the seasonal slowdown in light oil activity during the second quarter. Heavy oil production increased 2% (compared to Q1/2019) due largely to the ramp-up of our Kerrobert thermal expansion project.
- Based on the free cash flow generated in the first half of 2019, we intend to redeem the US$150 million principal amount of 6.75% senior unsecured notes at par during the third quarter.
- Using the forward strip for 2019[1], we are now forecasting adjusted funds flow for 2019 of approximately $875 million. Further deleveraging remains a top priority with adjusted funds flow exceeding the midpoint of our capital guidance by $300 million.

(1) Pricing assumptions: WTI - US$59/bbl; LLS - US$64/bbl; WCS differential - US$14/bbl; MSW differential – US$6/bbl, NYMEX Gas - US$2.70/mcf; AECO Gas - $1.50/mcf and Exchange Rate (CAD/USD) - 1.32.

	Three Months Ended			Six Months Ended	
	June 30, 2019	March 31, 2019	June 30, 2018	**June 30, 2019**	June 30, 2018
FINANCIAL (thousands of Canadian dollars, except per common share amounts)					
Petroleum and natural gas sales	**$ 482,000**	$ 453,424	$ 347,605	**$ 935,424**	$ 633,672
Adjusted funds flow [1]	**236,130**	220,770	106,690	**456,900**	190,945
Per share - basic	**0.42**	0.40	0.45	**0.82**	0.81
Per share - diluted	**0.42**	0.40	0.45	**0.82**	0.81
Net income (loss)	**78,826**	11,336	(58,761)	**90,162**	(121,483)
Per share - basic	**0.14**	0.02	(0.25)	**0.16**	(0.51)
Per share - diluted	**0.14**	0.02	(0.25)	**0.16**	(0.51)
Capital Expenditures					
Exploration and development expenditures [1]	**$ 106,246**	$ 153,843	$ 78,830	**$ 260,089**	$ 172,364
Acquisitions, net of divestitures	**1,647**	—	(21)	**1,647**	(2,047)
Total oil and natural gas capital expenditures	**$ 107,893**	$ 153,843	$ 78,809	**$ 261,736**	$ 170,317
Net Debt					
Bank loan [2]	**$ 414,691**	$ 550,751	$ 213,538	**$ 414,691**	$ 213,538
Long-term notes [2]	**1,543,645**	1,569,153	1,548,490	**1,543,645**	1,548,490
Long-term debt	**1,958,336**	2,119,904	1,762,028	**1,958,336**	1,762,028
Working capital deficiency	**70,350**	55,337	22,807	**70,350**	22,807
Net debt [1]	**$ 2,028,686**	$ 2,175,241	$ 1,784,835	**$ 2,028,686**	$ 1,784,835
Shares Outstanding - basic (thousands)					
Weighted average	**556,599**	555,438	236,628	**556,022**	236,472
End of period	**556,798**	555,872	236,662	**556,798**	236,662

	Three Months Ended			Six Months Ended	
	June 30, 2019	March 31, 2019	June 30, 2018	**June 30, 2019**	June 30, 2018
OPERATING					
Daily Production					
Light oil and condensate (bbl/d)	**42,585**	45,048	21,100	**43,809**	21,034
Heavy oil (bbl/d)	**27,320**	26,891	25,544	**27,107**	25,208
NGL (bbl/d)	**10,986**	11,729	9,419	**11,356**	9,281
Total liquids (bbl/d)	**80,891**	83,668	56,063	**82,272**	55,523
Natural gas (mcf/d)	**105,065**	104,682	87,605	**104,874**	87,434
Oil equivalent (boe/d @ 6:1) [3]	**98,402**	101,115	70,664	**99,751**	70,095
Netback (thousands of Canadian dollars)					
Total sales, net of blending and other expense [4]	**$ 461,110**	$ 436,636	$ 329,366	**$ 897,746**	$ 598,143
Royalties	**(86,617)**	(81,325)	(77,205)	**(167,942)**	(142,044)
Operating expense	**(100,474)**	(100,292)	(70,149)	**(200,766)**	(136,037)
Transportation expense	**(11,869)**	(13,330)	(7,836)	**(25,199)**	(16,355)
Operating netback [1]	**$ 262,150**	$ 241,689	$ 174,176	**$ 503,839**	$ 303,707
General and administrative	**(11,506)**	(14,136)	(10,563)	**(25,642)**	(21,571)
Cash financing and interest	**(28,092)**	(28,184)	(25,530)	**(56,276)**	(50,041)
Realized financial derivatives gain (loss)	**12,993**	18,814	(29,408)	**31,807**	(39,249)
Other [5]	**585**	2,587	(1,985)	**3,172**	(1,901)
Adjusted funds flow [1]	**$ 236,130**	$ 220,770	$ 106,690	**$ 456,900**	$ 190,945
Netback (per boe)					
Total sales, net of blending and other expense [4]	**$ 51.49**	$ 47.98	$ 51.22	**$ 49.72**	$ 47.15
Royalties	**(9.67)**	(8.94)	(12.01)	**(9.30)**	(11.20)
Operating expense	**(11.22)**	(11.02)	(10.91)	**(11.12)**	(10.72)
Transportation expense	**(1.33)**	(1.46)	(1.22)	**(1.40)**	(1.29)
Operating netback [1]	**$ 29.27**	$ 26.56	$ 27.08	**$ 27.90**	$ 23.94
General and administrative	**(1.28)**	(1.55)	(1.64)	**(1.42)**	(1.70)
Cash financing and interest	**(3.14)**	(3.10)	(3.97)	**(3.12)**	(3.94)
Realized financial derivatives gain (loss)	**1.45**	2.07	(4.57)	**1.76**	(3.09)
Other [5]	**0.07**	0.28	(0.31)	**0.19**	(0.16)
Adjusted funds flow [1]	**$ 26.37**	$ 24.26	$ 16.59	**$ 25.31**	$ 15.05

Notes:

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

(2) Principal amount of instruments. The carrying amount of debt issue costs associated with the bank loan and long-term notes are excluded on the basis that these amounts have been paid by Baytex and do not represent an additional source of 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 Q2/2019 MD&A for further information on these amounts.

Operating Results

Our operating results for the second quarter of 2019 were buoyed by an improved commodity price environment along with strong operating performance in the Eagle Ford and Canada. We continued to realize the benefits of the Baytex and Raging River combination as we increased our operating netback, delivered meaningful free cash flow and strengthened our balance sheet.

Production during the second quarter averaged 98,402 boe/d (82% oil and NGL), as compared to 101,115 boe/d (84% oil and NGL) in Q1/2019. Production in the first half of 2019 averaged 99,751 boe/d, exceeding the high end of our full-year production guidance range.

Exploration and development expenditures totaled $106 million in Q2/2019, bringing aggregate spending in the first half of 2019 to $260 million. We participated in the drilling of 67 (52.0 net) wells with a 98% success rate during the second quarter.

Eagle Ford and Viking Light Oil

Production in the Eagle Ford averaged 39,822 boe/d (76% liquids) during Q2/2019, as compared to 41,097 boe/d in Q1/2019. The lower volumes during the quarter reflect the timing of completion activity. We commenced production from 29 (5.0 net) wells during the second quarter, as compared to 36 (8.9 net) wells during the first quarter. The wells brought on-stream generated an average 30-day initial production rate of approximately 2,045 boe/d per well.

During Q2/2019, production from the Viking averaged 22,565 boe/d, as compared to 23,387 boe/d in Q1/2019. Our capital program in the second quarter included the seasonal slowdown, which resulted in the completion of 49 (40.0 net) wells, as compared to 79 (67.8 net) wells during the first quarter. We currently have four drilling rigs and one frac crew executing our program and remain on track to drill approximately 250 net wells this year. Inventory enhancement continues to be a priority. We have completed multiple deals and swaps year-to-date adding 160 net unbooked drilling opportunities.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 29,983 boe/d during the second quarter, as compared to 29,341 boe/d in Q1/2019. The higher volumes reflect the completion of three previously deferred wells at Peace River along with the ramp-up of our Kerrobert thermal expansion project.

With WCS differentials returning to historical levels, the returns associated with continued development of our heavy oil assets are competitive to those of our other plays. We expect to drill approximately 40 net heavy oil wells in the second half of 2019, as compared to nine net wells in the first half of the year.

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. During the first half of 2019 we drilled four wells that continued 45 sections of land and further confirmed the prospectivity of our Pembina acreage.

Two of these wells were completed and initial flow back rates are very encouraging. The first well (14-31) was brought on-stream June 27 and generated a 30-day initial production rate of 1,360 boe/d (76% liquids). The second well (3-19) was brought on-stream July 26 and is currently producing 1,063 boe/d (89% liquids). These two wells were fracture stimulated using a “plug and perf” system and were the first Baytex wells to utilize fracture diversion technology. The other two wells were drilled to depth and encountered thick, well-developed shale sections with highly favorable geological characteristics including natural fracturing. Unfortunately both of these wells had to be abandoned due to wellbore stability issues. Having conducted an in-depth review of these two wells, we developed an improved drilling process and will re-drill these locations in the future.

Well costs have significantly improved with our two successful wells drilled and completed for an average cost of approximately $7.0 million per well. This represents an approximate 20% reduction from the average cost of our previous wells. As the play moves from delineation to development, the efficiency from multi-well pad operations is expected to drive further cost reductions.

The success of our drilling program in the Pembina area has significantly de-risked our approximately 38 kilometer long acreage fairway, where we hold 268 sections (100% working interest) of Duvernay land.

Financial Review

Our adjusted funds flow in Q2/2019 increased 7% as compared to Q1/2019, driven by strong operating performance in an improved commodity price environment. We generated adjusted funds flow of $236 million ($0.42 per basic share) in Q2/2019, compared to $221 million ($0.40 per basic share) in Q1/2019.

In Q2/2019, the price for West Texas Intermediate light oil ("WTI") averaged US$59.81/bbl, as compared to US$54.90/bbl in Q1/2019. The discount for Canadian light oil, as measured by the price differential between Canadian Mixed Sweet Blend ("MSW") and WTI, averaged US$4.61/bbl in Q2/2019 as compared to US$4.85/bbl in Q1/2019.The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, averaged US$10.68/bbl in Q2/2019 as compared to US$12.29/bbl in Q1/2019. 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. In Q2/2019, the price for LLS averaged a US$7.34/bbl premium to WTI as compared to US$6.70/bbl in Q1/2019.

We generated an operating netback of $29.27/boe in Q2/2019, as compared to $26.56/boe in Q1/2019 and $27.08/boe in Q2/2018. Our Canadian operations generated an operating netback of $29.47/boe during Q2/2019 while our Eagle Ford asset generated an operating netback of $28.98/boe. Our operating netback in Canada has improved meaningfully with the inclusion of the high operating netback Viking light oil production.

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

	Three Months Ended June 30					
	2019			2018		
($ per boe except for production)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Production (boe/d)	**58,580**	**39,822**	**98,402**	34,042	36,622	70,664
Total sales, net of blending and other [1]	**$ 51.36**	**$ 51.69**	**$ 51.49**	$ 41.61	$ 60.16	$ 51.22
Royalties	**(5.80)**	**(15.37)**	**(9.67)**	(5.81)	(17.77)	(12.01)
Operating expense	**(13.86)**	**(7.34)**	**(11.22)**	(15.15)	(6.97)	(10.91)
Transportation expense	**(2.23)**	**—**	**(1.33)**	(2.53)	—	(1.22)
Operating netback [2]	**$ 29.47**	**$ 28.98**	**$ 29.27**	$ 18.12	$ 35.42	$ 27.08
Realized financial derivatives gain (loss)	**—**	**—**	**1.45**	—	—	(4.57)
Operating netback after financial derivatives	**$ 29.47**	**$ 28.98**	**$ 30.72**	$ 18.12	$ 35.42	$ 22.51

Notes:

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

(2) The term "operating netback" does not have any standardized meaning as prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. See the advisory on non-GAAP measures at the end of this press release.

Financial Liquidity

We are delivering on our commitment to generate meaningful free cash flow and improve our balance sheet. In aggregate, we reduced net debt by $147 million during the second quarter ($236 million year-to-date) as adjusted funds flow exceeded capital expenditures and the Canadian dollar strengthened relative to the U.S. dollar.

Our net debt, which includes our bank loan, long-term notes and working capital, totaled $2.0 billion at June 30, 2019. We maintain strong financial liquidity with our credit facilities approximately 60% undrawn and our first long-term note maturity not until 2021.

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 $1.05 billion, comprised of US$575 million of revolving credit facilities and a $300 million non-revolving term loan.

Subsequent to quarter-end, we initiated plans to redeem US$150 million principal amount of 6.75% senior unsecured notes due February 17, 2021. Redemption of the notes is expected to occur during the third quarter and will be funded from the free cash flow generated during the first half of 2019.

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 $13 million in Q2/2019.

For the balance of 2019, we have entered into hedges on approximately 48% of our net crude oil exposure. This includes 43% of our net WTI exposure with 18% fixed at US$62.82/bbl and 25% 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 11,500 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 Q2/2019 financial statements.

Outlook for 2019

Given our strong year-to-date operating performance, we are tightening our 2019 production guidance range to 96,000 to 97,000 boe/d (previously 95,000 to 97,000 boe/d) and lowering our budgeted exploration and development capital expenditure range to $550 to $600 million (previously $575 to $625 million).

Based on the forward strip for the balance of 2019[1], we are forecasting adjusted funds flow of approximately $875 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 trailing adjusted funds flow ratio is forecast to be 2.2x.

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 2019 annual guidance and compares it to our 2019 year-to-date actual results.

	Guidance	YTD 2019
Exploration and development capital ($ millions) [2]	$550 - $600	$260.1
Production (boe/d) [2]	96,000 - 97,000	99,751
Expenses:		
Royalty rate (%) [2]	19%	18.7%
Operating ($/boe)	$10.75 - $11.25	$11.12
Transportation ($/boe)	$1.25 - $1.35	$1.40
General and administrative ($ millions)	$46 ($1.30/boe)	$25.6 ($1.42/boe)
Interest ($ millions)	$112 ($3.23/boe)	$56.3 ($3.12/boe)
Leasing expenditures ($ millions)	$5	3.0
Asset retirement obligations ($ millions)	$17	9.7

(1) 2019 full year pricing assumptions: WTI - US$59/bbl; LLS - US$64/bbl; WCS differential - US$14/bbl; MSW differential – US$6/bbl, NYMEX Gas - US$2.70/mcf; AECO Gas - $1.50/mcf and Exchange Rate (CAD/USD) - 1.32.

(2) Our exploration and development capital and production guidance along with the expected royalty rate for 2019 has been updated as of August 1, 2019. Original guidance from December 2018: production – 93,000-97,000 boe/d; exploration and development capital - $550-$650 million; royalty rate - 20%.

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	$28.3	$18.2
Change of US$1.00/bbl WCS heavy oil differential	$11.4	$9.5
Change of US$1.00/bbl MSW light oil differential	$9.2	$7.7
Change of US$0.25/mcf NYMEX natural gas	$9.4	$7.5
Change of $0.01 in the CAD/USD exchange rate	$11.0	$11.0

Additional Information

Our condensed consolidated interim unaudited financial statements for the three and six months ended June 30, 2019 and the related Management's Discussion and Analysis of the operating and financial results can be accessed on our website at www.baytexenergy.com and will be available shortly through SEDAR at www.sedar.com and EDGAR at www.sec.gov/edgar.shtml.

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

Baytex will host a conference call today, August 1, 2019, starting at 9:00am MDT (11:00am EDT). To participate, please dial toll free in North America 1-800-319-4610 or international 1-416-915-3239. Alternatively, to listen to the conference call online, please enter http://services.choruscall.ca/links/baytexq220190801.html in your web browser.

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

Advisory Regarding Forward-Looking Statements

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

Specifically, this press release contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our 2019 production and capital expenditure guidance; that we will redeem our US $150 million senior unsecured notes with free cash flow generated in H1/2019; our per well drill and complete cost for the East Duvernay; that the Pembina region of the East Duvernay shale is highly prospective; our forecast for 2019 adjusted funds flow; that deleveraging remains a top priority; in the Viking: that we expect to drill 250 wells in 2019 and inventory enhancement remains a priority; that WCS differentials mean that our heavy oil assets are competitive to our other assets and that we intend to drill 40 net wells on our heavy oil wells in H2/2019; in the East Duvernay shale: that we continue to prudently advance the delineation of the asset, that we have developed an improved drilling process, the locations we will drill in the future, our expectation that multi-well pad operations will drive cost reductions in the future and that we have de-risked our 38 kilometer acreage faiway; our ability to partially reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts for commodity prices, foreign exchange rates and interest rates; the percentage of our net crude oil and natural gas exposure that is hedged for 2019 and 2020 and the amount and percentage of heavy oil production we expect to delivery by crude by rail and the percentage of crude by rail deliveries that do not have WCS exposure; our planned uses for adjusted funds flow in 2019; our forecast year end 2019 net debt to adjusted funds flow ratio; that we will be positioned to enhance shareholder returns through organic growth, capital allocation, the reinstatement of a dividend and/or share buybacks; guidance for 2019 capital spending and production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligation expenditures; the sensitivity of our 2019 adjusted funds flow to changes in WTI, WCS, MSW and NYMEX prices and the C$/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 and six months ended June 30, 2019.

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

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

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of trade and other accounts receivable, trade and other accounts payable, and the principal amount of both the long-term notes and the bank loan. We believe that this measure assists in providing a more complete understanding of our cash liabilities and provides a key measure to assess our liquidity. We use the principal amounts of the bank loan and long-term notes outstanding in the calculation of net debt as these amounts represent our ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the bank loan and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of 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

This press release discloses the acquisition of 160 net unbooked drilling opportunities in our Viking asset. The additional drilling opportunities are unbooked locations and are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production.

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

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

Baytex Energy Corp.

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

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

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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 and six months ended June 30, 2019. This information is provided as of July 31, 2019. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three and six months ended June 30, 2019 ("Q2/2019" and "YTD 2019") have been compared with the results for the three and six months ended June 30, 2018 ("Q2/2018" and "YTD 2018"). This MD&A should be read in conjunction with the Company's condensed consolidated interim financial statements ("consolidated financial statements") for the three and six months ended June 30, 2019, its audited comparative consolidated financial statements for the years ended December 31, 2018 and 2017, together with the accompanying notes, and its Annual Information Form for the year ended December 31, 2018. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated.

In this MD&A, barrel of oil equivalent ("boe") amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil, which represents an energy equivalency conversion method applicable at the burner tip and does not represent a value equivalency at the wellhead. While it is useful for comparative measures, it may not accurately reflect individual product values and may be misleading if used in isolation.

This MD&A contains forward-looking information and statements along with certain measures which do not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). The terms "adjusted funds flow", "operating netback", "exploration and development expenditures", "net debt", and "bank EBITDA" do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to similar measures presented by other companies where similar terminology is used. We refer you to our advisory on forward-looking information and statements and a summary of our non-GAAP measures at the end of the MD&A.

BAYTEX ENERGY CORP.

Baytex Energy Corp. is a North American focused oil and gas company based in Calgary, Alberta. The company has oil and gas operations in Canada and the United States. The Canadian operating segment includes our light oil assets in the Viking and Duvernay, our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. operating segment includes our Eagle Ford assets in Texas.

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

SECOND QUARTER HIGHLIGHTS

Baytex delivered solid operating and financial results in Q2/2019, generating adjusted funds flow of $236.1 million which exceeded exploration and development expenditures of $106.2 million and contributed to a $146.6 million reduction in net debt from Q1/2019. Strong well performance in the U.S. and Canada resulted in production of 98,402 boe/d which exceeds the high end of our revised annual guidance range of 96,000 to 97,000 boe/d.

In the U.S., production was 39,822 boe/d for Q2/2019 which was consistent with our expectations and slightly lower than 41,097 boe/d in Q1/2019 and 9% higher than 36,622 boe/d for Q2/2018. Strong well performance has increased our production from 2018, while lower activity in Q2/2019 from Q1/2019 resulted in the moderate decrease in production relative to Q1/2019. We invested $38.0 million on exploration and development activities during Q2/2019 and drilled 20 (5.1 net) wells and commenced production from 29 (5.0 net) wells. Lower completion activity in Q2/2019 resulted in exploration and development expenditures that were $10.2 million lower than Q2/2018 when we invested $48.2 million and drilled 18 (2.6 net) wells and commenced production from 32 (7.6 net) wells.

In Canada, production was 58,580 boe/d for Q2/2019 which was slightly lower than 60,018 boe/d in Q1/2019 but 72% higher than 34,042 boe/d in Q2/2018 which reflects the impact of the Strategic Combination along with an increase in heavy oil production from our development program. Production of 59,296 boe/d for YTD 2019 is relatively consistent with 60,453 boe/d for Q4/2018 despite production curtailments mandated by the Government of Alberta which became effective in January 2019. Exploration and development expenditures of $68.3 million in Q2/2019 were focused on our Viking and Duvernay light oil properties. Exploration and development expenditures included costs associated with drilling 43 (42.9 net) light oil wells and 4 (4.0 net) heavy oil wells during Q2/2019.

The West Texas Intermediate ("WTI") benchmark price for crude oil was lower in Q2/2019 compared to Q2/2018. The WTI oil price averaged US$59.81/bbl in Q2/2019 which was down US$8.07/bbl from US$67.88/bbl in Q2/2018 and up US$4.91/bbl from US$54.90/bbl in Q1/2019. 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 YTD 2019. The Edmonton par light oil benchmark averaged $73.84/bbl in Q2/2019 which represents a differential of US$4.61/bbl to WTI as compared to a US$26.51 differential in Q4/2018 and a US$5.47/bbl differential in Q2/2018. The Western Canadian Select ("WCS") heavy oil differential averaged US$10.68/bbl in Q2/2019 relative to a differential of US$39.42/bbl in Q4/2018 and US$19.28/bbl in Q2/2018.

Adjusted funds flow of $236.1 million in Q2/2019 was $129.4 million higher than $106.7 million for Q2/2018 due to stronger price realizations in Canada along with 39% increase in production for Q2/2019 relative to Q2/2018. Our realized price of $51.49/boe for Q2/2019 is consistent with $51.22/boe for Q2/2018 and reflects stronger pricing received on our Canadian light oil production and narrower WCS differentials which was offset by lower realized pricing on our U.S. production with lower WTI pricing. Increased production from the Strategic Combination and stronger price realizations in Canada resulted in a $131.7 million increase in total sales, net of blending and other expense, for Q2/2019 relative to Q2/2018. This was offset by a $43.8 million increase in royalties, operating and transportation expense associated with the increase in production resulting in a $88.0 million increase in operating netback in Q2/2019 relative to Q2/2018. Realized hedging gains of $13.0 million contributed to the increase in adjusted funds flow relative to Q2/2018 when we recorded realized hedging losses of $29.4 million.

In Q2/2019 we reported net income of $78.8 million compared to a net loss of $58.8 million in Q2/2018. In addition to the $129.4 million increase in adjusted funds flow in Q2/2019 compared to Q2/2018, unrealized gains on finance derivatives and foreign exchange exceeded losses in Q2/2018 by $110.0 million. This was offset by depletion and depreciation expense that was $73.9 million higher in Q2/2019 compared to Q2/2018. Our deferred tax recovery of $1.6 million for Q2/2019 was $23.0 million lower than $24.6 million for Q2/2018 due to higher net income before income tax which was partially offset by a $10.6 million recovery associated with a reduction in future tax rates in Alberta.

At June 30, 2019, net debt was $2,028.7 million, a $236.5 million decrease from $2,265.2 million at December 31, 2018. Net debt has decreased as adjusted funds flow has exceeded exploration and development expenditures for YTD 2019 by $196.8 million and the Canadian dollar strengthened at June 30, 2019 which reduced the reported amount of our US denominated long-term notes by $52.7 million. The change in net debt also reflects $9.7 million of asset retirement obligations settled and $3.0 million of lease payments for YTD 2019.

2019 GUIDANCE

The following table compares our 2019 annual guidance to our YTD 2019 results. As a result of our strong operational performance in YTD 2019 we are tightening our 2019 production guidance range to 96,000 to 97,000 boe/d with exploration and development expenditures of $550 to $600 million. We are also reducing our expected royalty rate for 2019 from approximately 20.0% to 19.0%.

	Previous Annual Guidance [1]	Revised Annual Guidance	YTD 2019
Exploration and development capital	$575 - 625 million	$550 - 600 million	$260.1 million
Production (boe/d)	95,000 - 97,000	96,000 to 97,000	99,751
Expenses:			
Royalty rate	~ 20.0%	~ 19.0%	18.7%
Operating	$10.75 - $11.25/boe	No change	$11.12/boe
Transportation	$1.25 - $1.35/boe	No change	$1.40/boe
General and administrative	~ $46 million ($1.30/boe)	No change	$25.6 million ($1.42/boe)
Cash interest	~ $112 million ($3.23/boe)	No change	$56.3 million ($3.12/boe)

(1) As announced on May 2, 2019.

RESULTS OF OPERATIONS

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

Production

	Three Months Ended June 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**22,130**	**20,455**	**42,585**	842	20,258	21,100
Heavy oil	**27,320**	**—**	**27,320**	25,544	—	25,544
Natural Gas Liquids (NGL)	**1,106**	**9,880**	**10,986**	1,214	8,205	9,419
Total liquids (bbl/d)	**50,556**	**30,335**	**80,891**	27,600	28,463	56,063
Natural gas (mcf/d)	**48,145**	**56,920**	**105,065**	38,650	48,955	87,605
Total production (boe/d)	**58,580**	**39,822**	**98,402**	34,042	36,622	70,664
Production Mix						
Light oil and condensate	**38%**	**51%**	**43%**	2%	56%	30%
Heavy oil	**47%**	**—%**	**28%**	75%	—%	36%
NGL	**2%**	**25%**	**11%**	4%	22%	13%
Natural gas	**13%**	**24%**	**18%**	19%	22%	21%

	Six Months Ended June 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**22,709**	**21,100**	**43,809**	850	20,184	21,034
Heavy oil	**27,107**	**—**	**27,107**	25,208	—	25,208
Natural Gas Liquids (NGL)	**1,356**	**10,000**	**11,356**	1,256	8,025	9,281
Total liquids (bbl/d)	**51,172**	**31,100**	**82,272**	27,314	28,209	55,523
Natural gas (mcf/d)	**48,742**	**56,132**	**104,874**	38,761	48,673	87,434
Total production (boe/d)	**59,296**	**40,455**	**99,751**	33,774	36,321	70,095
Production Mix						
Light oil and condensate	**38%**	**52%**	**44%**	3%	56%	30%
Heavy oil	**46%**	**—%**	**27%**	75%	—%	36%
NGL	**2%**	**25%**	**11%**	4%	22%	13%
Natural gas	**14%**	**23%**	**18%**	18%	22%	21%

Production averaged 98,402 boe/d for Q2/2019 and 99,751 for YTD 2019 which exceeds the high end of our revised annual guidance range of 96,000 to 97,000 boe/d. Production in 2019 is higher than 2018 due to the Strategic Combination, increased U.S. production from strong well results along with additional production related to our development program.

In Canada, production was 58,580 boe/d for Q2/2019 and 59,296 boe/d for YTD 2019 compared to 34,042 boe/d in Q2/2018 and 33,774 boe/d in YTD 2018. The increase in production in 2019 relative to 2018 is primarily due to the production contribution from the Strategic Combination along with strong production results from our exploration and development program. Production from our Viking and Duvernay properties consists of approximately 90% light oil which resulted in a higher proportion of our Canadian production being comprised of light oil in both periods of 2019 relative to 2018.

Production in the U.S. averaged 39,822 boe/d for Q2/2019 and 40,455 boe/d in YTD 2019 compared to 36,622 boe/d for Q2/2018 and 36,321 boe/d in YTD 2018. Strong well performance from wells that commenced production during Q2/2019 contributed to the increase in production relative to Q2/2018. Average daily production for YTD 2019 was 4,134 boe/d higher than 36,321 boe/d in YTD 2018 due to the timing of completion activity and strong well performance. During YTD 2019 we commenced production from 65 (14.0 net) wells compared to YTD 2018 when 59 (13.1 net) wells were brought on production.

We have narrowed our annual production guidance range for 2019 from 95,000 to 97,000 to 96,000 to 97,000 boe/d, increasing the midpoint of our range by 500 boe/d reflecting the positive performance in YTD 2019. Lower exploration and development expenditures during Q2/2019 are expected to result in lower production levels during Q3/2019.

Commodity Prices

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

Crude Oil

Global benchmark prices have improved in 2019 from Q4/2018 when increasing production and geopolitical factors contributed to a sharp decline in global oil prices but have decreased from Q2/2018 when OPEC production curtailments and global inventory levels supported higher prices. The WTI benchmark price averaged US$59.81/bbl during Q2/2019 and US$57.36/bbl in YTD 2019, representing a decrease of US$8.07/bbl and US$8.01/bbl compared to US$67.88/bbl in Q2/2018 and US$65.37/bbl in YTD 2018.

We compare the price received for our U.S. crude oil production to the Louisiana Light Sweet ("LLS") stream at St. James, Louisiana, which is a representative benchmark for light oil pricing at the U.S. Gulf coast. LLS averaged US$67.15/bbl during Q2/2019 and US $64.37/bbl during YTD 2019 compared to US$71.37/bbl in Q2/2018 and US$69.24/bbl in YTD 2018. The LLS premium to WTI of US $7.34/bbl and US$7.01/bbl for Q2/2019 and YTD 2019, respectively, has been higher than US$3.49 and US$3.87 for the same periods in 2018 which has slightly offset the decrease in WTI pricing during 2019.

Ongoing pipeline capacity constraints, a lack of rail transport capacity and increasing Western Canadian crude oil production resulted in the WCS and Edmonton benchmark prices trading at wide discounts to WTI in late 2018. Production curtailments mandated by the Government of Alberta have narrowed the Canadian oil differentials in YTD 2019 and resulted in the WCS heavy differential averaging US$11.48/bbl and the Edmonton par differential averaging US$4.72/bbl for YTD 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 $73.84/bbl for Q2/2019 and $70.19/bbl for YTD 2019 compared to $80.58/bbl for Q2/2018 and $76.32/bbl for YTD 2018. Edmonton par traded at a US$4.61/bbl discount to WTI in Q2/2019 and a discount of US$4.72/bbl in YTD 2019 compared to a US$5.47/bbl discount in Q2/2018 and a US$5.66/bbl discount in YTD 2018.

The price received for our heavy oil production in Canada is based on the WCS benchmark price which is the representative benchmark for heavy grades of crude oil in Western Canada. The WCS heavy oil differential to WTI averaged US$10.68/bbl in Q2/2019 and US $11.48/bbl in YTD 2019 as compared to US$19.28/bbl for Q2/2018 and US$21.77 for YTD 2018. As a result, the WCS heavy oil benchmark price of $61.17/bbl in YTD 2019 increased $5.44/bbl from $55.73/bbl in YTD 2018 despite a $7.08/bbl decrease in WTI (expressed in Canadian dollars) over the same periods.

Natural Gas

North American natural gas prices for Q2/2019 and YTD 2019 were fairly consistent with Q2/2018 and YTD 2018 as increased demand due to cold weather in 2019 mitigated the impact of significant North American natural gas supply growth. Canadian natural gas prices remained challenged during YTD 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. The NYMEX natural gas benchmark averaged US$2.64/mmbtu in Q2/2019 and US$2.89/mmbtu in YTD 2019 which is slightly lower in the quarter and relatively consistent year-to-date with US$2.80/mmbtu and US$2.90/mmbtu for the same periods 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 $1.17/mcf during Q2/2019 and $1.56/mcf in YTD 2019 which is slightly higher than $1.03/mcf for Q2/2018 and $1.44/mcf in YTD 2018.

The following tables compare selected benchmark prices and our average realized selling prices for the three and six months ended June 30, 2019 and 2018.

	Three Months Ended June 30			Six Months Ended June 30		
	2019	2018	Change	**2019**	2018	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	**59.81**	67.88	(8.07)	**57.36**	65.37	(8.01)
LLS oil (US$/bbl)[2]	**67.15**	71.37	(4.22)	**64.37**	69.24	(4.87)
LLS oil differential to WTI (US$/bbl)	**7.34**	3.49	3.85	**7.01**	3.87	3.14
Edmonton par oil ($/bbl)	**73.84**	80.58	(6.74)	**70.19**	76.32	(6.13)
Edmonton par oil differential to WTI (US$/bbl)	**(4.61)**	(5.47)	0.86	**(4.72)**	(5.66)	0.94
WCS heavy oil ($/bbl)[3]	**65.73**	62.75	2.98	**61.17**	55.73	5.44
WCS heavy oil differential to WTI (US$/bbl)	**(10.68)**	(19.28)	8.60	**(11.48)**	(21.77)	10.29
AECO natural gas price ($/mcf)[4]	**1.17**	1.03	0.14	**1.56**	1.44	0.12
NYMEX natural gas price (US$/mmbtu)[5]	**2.64**	2.80	(0.16)	**2.89**	2.90	(0.01)
CAD/USD average exchange rate	**1.3376**	1.2911	0.0465	**1.3334**	1.2781	0.0553

(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 June 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices[1]						
Light oil and condensate ($/bbl)	**$ 70.43**	**$ 82.47**	**$ 76.21**	$ 71.61	$ 87.38	$ 86.75
Heavy oil ($/bbl)[2]	**50.34**	**—**	**50.34**	49.70	—	49.70
NGL ($/bbl)	**17.46**	**17.58**	**17.57**	37.05	30.53	31.37
Natural gas ($/mcf)	**1.16**	**3.47**	**2.41**	1.07	3.73	2.56
Weighted average ($/boe)[2]	**$ 51.36**	**$ 51.69**	**$ 51.49**	$ 41.61	$ 60.16	$ 51.22

	Six Months Ended June 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices[1]						
Light oil and condensate ($/bbl)	**$ 66.71**	**$ 79.19**	**$ 72.72**	$ 67.18	$ 83.68	$ 83.01
Heavy oil ($/bbl)[2]	**46.07**	**—**	**46.07**	41.67	—	41.67
NGL ($/bbl)	**21.18**	**20.23**	**20.34**	32.76	28.21	28.82
Natural gas ($/mcf)	**1.77**	**3.71**	**2.81**	1.50	3.75	2.75
Weighted average ($/boe)[2]	**$ 48.55**	**$ 51.44**	**$ 49.72**	$ 35.73	$ 57.76	$ 47.15

(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 $51.49/boe for Q2/2019 and $49.72/boe for YTD 2019 compared to $51.22/boe for Q2/2018 and $47.15/boe in YTD 2018. Our realized price in the U.S. was $51.69/boe in Q2/2019 which is $8.47/boe lower than $60.16/boe in Q2/2018 due to the decrease in U.S. crude oil benchmark prices. In Canada, our realized price of $51.36/boe for Q2/2019 was $9.75/boe higher than $41.61/boe for Q2/2018 due to a narrowing of Canadian light and heavy oil differentials 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 was $70.43/bbl in Q2/2019 and $66.71/bbl in YTD 2019 compared to $71.61/bbl in Q2/2018 and $67.18/bbl in YTD 2018. Our realized light oil and condensate price for Q2/2019 and YTD 2019 represents a discount of $3.41/bbl and $3.48/bbl to the Edmonton par price compared to a discount of $8.97/bbl in Q2/2018 and $9.14/bbl in YTD 2018. 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 receive higher 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 $82.47/bbl for Q2/2019 and $79.19/bbl for YTD 2019 compared to $87.38/bbl for Q2/2018 and $83.68/bbl in YTD 2018. Expressed in U.S. dollars, our realized light oil and condensate price of US$61.66/bbl for Q2/2019 and US$59.39/bbl for YTD 2019 represents a US$5.49/bbl discount to the LLS benchmark for Q2/2019 and a US$4.98/bbl discount for YTD 2019. Our light oil and condensate pricing in the U.S. was impacted by a change in reference price on certain marketing contracts in Q1/2019 which resulted in lower price realizations relative to Q2/2018 and YTD 2018 when our realized price expressed in U.S. dollars was a US$3.69/bbl and US$3.77/bbl discount to the LLS benchmark.

Our realized heavy oil price, net of blending and other expense averaged $50.34/bbl in Q2/2019 and $46.07/bbl for YTD 2019 compared to $49.70/bbl in Q2/2018 and $41.67/bbl in YTD 2018. Our realized heavy oil price for Q2/2019 and YTD 2019 was $0.64/bbl and $4.40/bbl higher relative to Q2/2018 and YTD 2018 compared to a $2.98/bbl and $5.44/bbl increase in the WCS benchmark over the same periods. While our realized heavy oil price has improved in 2019 it did not increase as much as the WCS benchmark due to certain WTI based heavy oil marketing contracts that were entered into prior to the Government of Alberta's decision to curtail production which resulted in a narrowing of the WCS differential.

Our realized NGL price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes and changes in the market prices of the underlying products. Our realized NGL price was $17.57/bbl in Q2/2019 or 22% of WTI (expressed in Canadian dollars) compared to $31.37/bbl or 36% of WTI (expressed in Canadian dollars) in Q2/2018. Our YTD 2019 realized NGL price was $20.34/bbl or 27% of WTI (expressed in Canadian dollars) compared to $28.82/bbl or 34% of WTI (expressed in Canadian dollars) for YTD 2018. The decrease in our realized NGL price for Q2/2019 and YTD 2019 is a result in the decline in market prices for propane and butane relative to Q2/2018 and YTD 2018.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price was $1.16/mcf for Q2/2019 and $1.77/mcf for YTD 2019 compared to $1.07/mcf in Q2/2018 and $1.50/mcf in YTD 2018. The increase in our realized natural gas prices in 2019 compared to 2018 is relatively consistent with the change in the AECO natural gas price over the same periods. In the U.S., our realized natural gas price was US$2.59/mmbtu for Q2/2019 and US$2.78/mmbtu for YTD 2019 compared to US$2.89/mmbtu in Q2/2018 and US$2.93/mmbtu in YTD 2018. Our realized natural gas price in the U.S. is relatively consistent with the NYMEX benchmark in both periods of 2019 and 2018.

Petroleum and Natural Gas Sales

	Three Months Ended June 30					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 141,827**	**$ 153,504**	**$ 295,331**	$ 5,484	$ 161,078	$ 166,562
Heavy oil	**146,038**	**—**	**146,038**	133,768	—	133,768
NGL	**1,757**	**15,808**	**17,565**	4,092	22,794	26,886
Total oil sales	**289,622**	**169,312**	**458,934**	143,344	183,872	327,216
Natural gas sales	**5,076**	**17,990**	**23,066**	3,778	16,611	20,389
Total petroleum and natural gas sales	**294,698**	**187,302**	**482,000**	147,122	200,483	347,605
Blending and other expense	**(20,890)**	**—**	**(20,890)**	(18,239)	—	(18,239)
Total sales, net of blending and other expense	**$ 273,808**	**$ 187,302**	**$ 461,110**	$ 128,883	$ 200,483	$ 329,366

	Six Months Ended June 30					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 274,195**	**$ 302,419**	**$ 576,614**	$ 10,336	$ 305,684	$ 316,020
Heavy oil	**263,724**	**—**	**263,724**	225,651	—	225,651
NGL	**5,198**	**36,610**	**41,808**	7,448	40,972	48,420
Total oil sales	**543,117**	**339,029**	**882,146**	243,435	346,656	590,091
Natural gas sales	**15,620**	**37,658**	**53,278**	10,502	33,079	43,581
Total petroleum and natural gas sales	**558,737**	**376,687**	**935,424**	253,937	379,735	633,672
Blending and other expense	**(37,678)**	**—**	**(37,678)**	(35,529)	—	(35,529)
Total sales, net of blending and other expense	**$ 521,059**	**$ 376,687**	**$ 897,746**	$ 218,408	$ 379,735	$ 598,143

Total sales, net of blending and other expense, of $461.1 million for Q2/2019 increased $131.7 million from $329.4 million reported for Q2/2018 while total sales, net of blending and other expense, of $897.7 million for YTD 2019 was $299.6 million higher than $598.1 million in YTD 2018. The increase in Q2/2019 and YTD 2019 is primarily a result of higher production from the Strategic Combination. Stronger realized pricing in Canada from the narrowing of Canadian oil differentials and a higher weighting of light oil production was offset by lower realized pricing in the U.S. relative to the same periods of 2018.

In Canada, total sales, net of blending and other expense, was $273.8 million for Q2/2019 which is an increase of $144.9 million from Q2/2018. Total petroleum and natural gas sales increased with production due to the Strategic Combination and our oil exploration and development programs. The increase in our average realized price to $51.36/boe for Q2/2019 also contributed to higher total sales, net of blending and other expense, compared to Q2/2018 when our average realized price was $41.61/boe. Higher production and stronger realized pricing resulted in our total sales, net of blending and other expense, increasing to $521.1 million in YTD 2019 from $218.4 million in YTD 2018.

In the U.S., petroleum and natural gas sales were $187.3 million for Q2/2019 and decreased $13.2 million from $200.5 million reported for Q2/2018. Production for Q2/2019 was 3,200 boe/d higher relative to Q2/2018 and increased total sales by $15.1 million. This was offset by lower realized prices which were $8.47/boe lower in Q2/2019 compared to Q2/2018 and decreased total sales by $28.3 million. Lower realized pricing in YTD 2019 resulted in petroleum and natural gas sales of $376.7 million which was $3.0 million lower than $379.7 million for YTD 2018 despite a 4,134 boe/d increase in production over the same period.

Royalties

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

	Three Months Ended June 30					
	2019			2018		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 30,936**	**$ 55,681**	**$ 86,617**	$ 17,998	$ 59,207	$ 77,205
Average royalty rate[(1)]	**11.3%**	**29.7%**	**18.8%**	14.0%	29.5%	23.4%
Royalty rate per boe	**$ 5.80**	**$ 15.37**	**$ 9.67**	$ 5.81	$ 17.77	$ 12.01

	Six Months Ended June 30					
	2019			2018		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 56,120**	**$ 111,822**	**$ 167,942**	$ 29,332	$ 112,712	$ 142,044
Average royalty rate[(1)]	**10.8%**	**29.7%**	**18.7%**	13.4%	29.7%	23.7%
Royalty rate per boe	**$ 5.23**	**$ 15.27**	**$ 9.30**	$ 4.80	$ 17.14	$ 11.20

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

Royalties for Q2/2019 were $86.6 million and averaged 18.8% of total sales, net of blending and other expense, compared to $77.2 million or 23.4% for Q2/2018. Total royalties in YTD 2019 were $167.9 million or 18.7% of total sales, net of blending and other expenses compared to $142.0 million or 23.7% in YTD 2018. Total royalty expense is higher in Q2/2019 and YTD 2019 due to higher total sales, net of blending and other expense, relative to the same periods of 2018. Our Canadian royalty rate of 11.3% for Q2/2019 and 10.8% for YTD 2019 was lower than 14.0% for Q2/2018 and 13.4% for YTD 2018 due to the lower royalty rate on our Viking light oil properties which were acquired in the Strategic Combination. In the U.S., royalties for Q2/2019 and YTD 2019 averaged 29.7% of total petroleum and natural gas sales which is consistent with the same periods of 2018 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

Our average royalty rate was 18.7% for YTD 2019. We have reduced our annual royalty rate guidance for 2019 from approximately 20.0% to approximately 19.0% as our Canadian sales, which have a lower royalty rate, represented a higher percentage of total sales due to narrower light and heavy oil differentials than originally budgeted.

Operating Expense

	Three Months Ended June 30					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 73,877**	**$ 26,597**	**$ 100,474**	$ 46,924	$ 23,225	$ 70,149
Operating expense per boe	**$ 13.86**	**$ 7.34**	**$ 11.22**	$ 15.15	$ 6.97	$ 10.91

	Six Months Ended June 30					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 147,979**	**$ 52,787**	**$ 200,766**	$ 92,344	$ 43,693	$ 136,037
Operating expense per boe	**$ 13.79**	**$ 7.21**	**$ 11.12**	$ 15.11	$ 6.65	$ 10.72

Operating expense was $100.5 million ($11.22/boe) for Q2/2019 and $200.8 million ($11.12/boe) for YTD 2019 compared to $70.1 million ($10.91/boe) in Q2/2018 and $136.0 million ($10.72/boe) in YTD 2018. The increase in total operating expense is from higher production in Q2/2019 and YTD 2019 relative to Q2/2018 and YTD 2018 along with a slight increase in per unit operating expense.

In Canada, operating expense was $73.9 million ($13.86/boe) for Q2/2019 and $148.0 million ($13.79/boe) for YTD 2019 compared to $46.9 million ($15.15/boe) for Q2/2018 and $92.3 million ($15.11/boe) for YTD 2018. Total operating expense in Canada has increased with higher production following the Strategic Combination. Per unit operating costs of $13.86/boe for Q2/2019 and $13.79/boe in YTD 2019 decreased from $15.15/boe in Q2/2018 and $15.11/boe in YTD 2018 as our Viking and Duvernay properties have lower per unit operating expense relative to our other Canadian properties which resulted in lower per unit operating expense in Canada following the Strategic Combination.

U.S. operating expense was $26.6 million ($7.34/boe) for Q2/2019 and $52.8 million ($7.21/boe) for YTD 2019 compared to $23.2 million ($6.97/boe) for Q2/2018 and $43.7 million ($6.65/boe) for YTD 2018. The increase in total operating expense reflects higher U.S. production combined with a weaker Canadian dollar in Q2/2019 and YTD 2019 compared to Q2/2018 and YTD 2018. Expressed in U.S. dollars, per boe operating expense for our U.S. properties have been fairly consistent and were US$5.49/boe in Q2/2019 and US$5.41/boe in YTD 2019 compared to US$5.40/boe for Q2/2018 and US$5.20/boe in YTD 2018.

Operating expense of $11.12/boe for YTD 2019 is consistent with expectations and we are maintaining 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 and six months ended June 30, 2019 and 2018.

	Three Months Ended June 30					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 11,869**	**$ —**	**$ 11,869**	$ 7,836	$ —	$ 7,836
Transportation expense per boe	**$ 2.23**	**$ —**	**$ 1.33**	$ 2.53	$ —	$ 1.22

	Six Months Ended June 30					
	2019			2018		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 25,199**	**$ —**	**$ 25,199**	$ 16,355	$ —	$ 16,355
Transportation expense per boe	**$ 2.35**	**$ —**	**$ 1.40**	$ 2.68	$ —	$ 1.29

Transportation expense was $11.9 million ($1.33/boe) for Q2/2019 and $25.2 million ($1.40/boe) for YTD 2019 compared to $7.8 million ($1.22/boe) for Q2/2018 and $16.4 million ($1.29/boe) for YTD 2018. The increase in transportation expense for 2019 reflects additional oil trucking and transportation costs associated with our Viking and Duvernay light oil properties acquired as part of the Strategic Combination. Per unit transportation costs of $1.40/boe for YTD 2019 were in line with expectations and we are maintaining our annual guidance range of $1.25 - $1.35/boe for 2019.

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.

Blending and other expense was $20.9 million for Q2/2019 and $37.7 million for YTD 2019 which is relatively consistent with $18.2 million for Q2/2018 and $35.5 million for YTD 2018.

Financial Derivatives

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

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2019**	2018	Change	**2019**	2018	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ 12,501**	$ (30,558)	$ 43,059	**$ 30,313**	$ (40,824)	$ 71,137
Natural gas	**504**	1,150	(646)	**1,470**	1,575	(105)
Interest and financing	**(12)**	—	(12)	**24**	—	24
Total	**$ 12,993**	$ (29,408)	$ 42,401	**$ 31,807**	$ (39,249)	$ 71,056
Unrealized financial derivatives gain (loss)						
Crude oil	**$ 13,524**	$ (45,800)	$ 59,324	**$ (37,642)**	$ (63,459)	$ 25,817
Natural gas	**1,230**	(1,585)	2,815	**(350)**	(1,635)	1,285
Interest and financing	**(81)**	—	(81)	**(596)**	—	(596)
Total	**$ 14,673**	$ (47,385)	$ 62,058	**$ (38,588)**	$ (65,094)	$ 26,506
Total financial derivatives gain (loss)						
Crude oil	**$ 26,025**	$ (76,358)	$ 102,383	**$ (7,329)**	$ (104,283)	$ 96,954
Natural gas	**1,734**	(435)	2,169	**1,120**	(60)	1,180
Interest and financing	**(93)**	—	(93)	**(572)**	—	(572)
Total	**$ 27,666**	$ (76,793)	$ 104,459	**$ (6,781)**	$ (104,343)	$ 97,562

We recorded total financial derivative gains of $27.7 million for Q2/2019 and losses of $6.8 million for YTD 2019. Realized financial derivatives gains of $13.0 million for Q2/2019 and $31.8 million for YTD 2019 are primarily a result of the market prices for crude oil settling at levels below those set in our derivative contracts. The unrealized gain of $14.7 million for Q2/2019 and unrealized loss of $38.6 million for YTD 2019 is primarily a result of fluctuations in the futures prices for WTI which impacts the fair value of our contracts in place at June 30, 2019.

Realized gains on crude oil financial derivatives of $12.5 million in Q2/2019 and $30.3 million for YTD 2019 are primarily a result of market prices for Brent and WTI settling at levels below the prices set in our contracts outstanding during the periods. Our natural gas financial derivatives generated gains of $0.5 million in Q2/2019 and $1.5 million for YTD 2019. These gains were primarily a result of the NYMEX index for Q2/2019 and YTD 2019 averaging less than the fixed price on our NYMEX contracts in place for both periods.

During Q2/2019 we recorded unrealized gains of $14.7 million as the fair value of our financial derivative contracts at June 30, 2019 increased from a net asset of $26.3 million at March 31, 2019 to a net asset of $41.0 million at June 30, 2019. The increase in the fair value of our financial derivatives during Q2/2019 is a result of a decline in the futures pricing for WTI and Brent at June 30, 2019 relative to March 31, 2019. We recorded an unrealized loss on financial derivatives of $38.6 million for YTD 2019 due to improved futures pricing at June 30, 2019 relative to December 31, 2018 when the fair value of our financial derivatives was a net asset of $79.6 million.

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

	Period	Volume	Price/Unit[1]	Index
Oil				
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
Basis Swap	Jul 2019 to Dec 2019	4,000 bbl/d	WTI less US$8.00/bbl	MSW
Fixed - Sell	Jul 2019 to Dec 2019	10,000 bbl/d	US$62.82/bbl	WTI
3-way option[2]	Jul 2019 to Dec 2019	2,000 bbl/d	US$49.00/US$61.70/US$75.00	WTI
3-way option[2]	Jul 2019 to Dec 2019	2,000 bbl/d	US$50.00/US$60.00/US$70.00	WTI
3-way option[2]	Jul 2019 to Dec 2019	1,000 bbl/d	US$55.00/US$65.00/US$72.60	WTI
3-way option[2]	Jul 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$72.50	WTI
3-way option[2]	Jul 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$73.00	WTI
3-way option[2]	Jul 2019 to Dec 2019	2,000 bbl/d	US$57.00/US$67.00/US$73.00	WTI
3-way option[2]	Jul 2019 to Dec 2019	2,000 bbl/d	US$58.00/US$68.00/US$74.00	WTI
3-way option[2]	Jul 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$69.90/US$75.00	WTI
3-way option[2]	Jul 2019 to Dec 2019	1,000 bbl/d	US$61.00/US$71.00/US$76.00	WTI
3-way option[2]	Jul 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$78.00	WTI
3-way option[2]	Jul 2019 to Dec 2019	1,000 bbl/d	US$55.50/US$65.50/US$75.50	Brent
3-way option[2]	Jul 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$70.00/US$77.55	Brent
3-way option[2]	Jul 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$83.00	Brent
3-way option[2]	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI
3-way option[2]	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI
3-way option[2]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI
3-way option[2]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI
3-way option[2]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI
3-way option[2]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI
3-way option[2]	Jan 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	WTI
Swaption[3]	Jan 2020 to Dec 2020	1,000 bbl/d	US$62.50/bbl	WTI
Swaption[3]	Jan 2020 to Dec 2020	1,000 bbl/d	US$63.20/bbl	WTI
Natural Gas				
Fixed - Sell	Jul 2019 to Dec 2019	5,000 mmbtu/d	US$3.15	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.

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

Period	Volume
Jul 2019 to Oct 2019	1,000 bbl/d
Jul 2019 to Dec 2019	10,000 bbl/d
Jan 2020 to Dec 2020	7,500 bbl/d

Operating Netback

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

	Three Months Ended June 30					
	2019			2018		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**58,580**	**39,822**	**98,402**	34,042	36,622	70,664
Operating netback:						
Total sales, net of blending and other expense	**$ 51.36**	**$ 51.69**	**$ 51.49**	$ 41.61	$ 60.16	$ 51.22
Less:						
Royalties	**(5.80)**	**(15.37)**	**(9.67)**	(5.81)	(17.77)	(12.01)
Operating expense	**(13.86)**	**(7.34)**	**(11.22)**	(15.15)	(6.97)	(10.91)
Transportation expense	**(2.23)**	**—**	**(1.33)**	(2.53)	—	(1.22)
Operating netback	**$ 29.47**	**$ 28.98**	**$ 29.27**	$ 18.12	$ 35.42	$ 27.08
Realized financial derivatives gain (loss)	**—**	**—**	**1.45**	—	—	(4.57)
Operating netback after financial derivatives	**$ 29.47**	**$ 28.98**	**$ 30.72**	$ 18.12	$ 35.42	$ 22.51

	Six Months Ended June 30					
	2019			2018		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**59,296**	**40,455**	**99,751**	33,774	36,321	70,095
Operating netback:						
Total sales, net of blending and other expense	**$ 48.55**	**$ 51.44**	**$ 49.72**	$ 35.73	$ 57.76	$ 47.15
Less:						
Royalties	**(5.23)**	**(15.27)**	**(9.30)**	(4.80)	(17.14)	(11.20)
Operating expense	**(13.79)**	**(7.21)**	**(11.12)**	(15.11)	(6.65)	(10.72)
Transportation expense	**(2.35)**	**—**	**(1.40)**	(2.68)	—	(1.29)
Operating netback	**$ 27.18**	**$ 28.96**	**$ 27.90**	$ 13.14	$ 33.97	$ 23.94
Realized financial derivatives gain (loss)	**—**	**—**	**1.76**	—	—	(3.09)
Operating netback after financial derivatives	**$ 27.18**	**$ 28.96**	**$ 29.66**	$ 13.14	$ 33.97	$ 20.85

Our operating netback after financial derivatives was $30.72/boe for Q2/2019 which was $8.21/boe higher than $22.51/boe for Q2/2018. Operating netback after financial derivatives of $29.66 for YTD 2019 was $8.81/boe higher than $20.85/boe for the same period of 2018. The increase in both periods of 2019 was driven by higher realized pricing in Canada which was slightly offset by lower pricing in our U.S operations relative to the same periods of 2018. We recorded realized gains on financial derivatives of $1.45/boe in Q2/2019 and $1.76/boe in YTD 2019 which increased our operating netback after financial derivatives compared Q2/2018 and YTD 2018 when we recorded realized losses of $4.57/boe and $3.09/boe.

In Canada, our operating netback increased to $29.47/boe in Q2/2019 and $27.18/boe in YTD 2019 from $18.12/boe in Q2/2018 and $13.14/boe in YTD 2018. The increase in our netback was primarily from an increase in our realized sales price per boe during Q2/2019 and YTD 2019 which was driven by a higher portion of our production coming from light oil after the Strategic Combination along with narrower Canadian oil differentials. Our operating netback in the U.S. of $28.98/boe in Q2/2019 and $28.96/boe in YTD 2019 was lower than $35.42/boe in Q2/2018 and $33.97/boe in YTD 2018 as our realized sales price decreased with lower benchmark pricing in both periods of 2019 relative to 2018.

General and Administrative Expense

General and administrative ("G&A") expense includes head office and corporate costs such as salaries and employee benefits, public company costs and administrative recoveries earned for operating 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 and six months ended June 30, 2019 and 2018.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2019**	2018	Change	**2019**	2018	Change
Gross general and administrative expense	**$ 12,655**	$ 12,286	$ 369	**$ 28,274**	$ 25,322	$ 2,952
Overhead recoveries	**(1,149)**	(1,723)	574	**(2,632)**	$ (3,751)	1,119
General and administrative expense	**$ 11,506**	$ 10,563	$ 943	**$ 25,642**	$ 21,571	$ 4,071
General and administrative expense per boe	**$ 1.28**	$ 1.64	$ (0.36)	**$ 1.42**	$ 1.70	$ (0.28)

We reported G&A expense of $11.5 million ($1.28/boe) for Q2/2019 and $25.6 million ($1.42/boe) for YTD 2019 compared to $10.6 million ($1.64/boe) for Q2/2018 and $21.6 million ($1.70/boe) for YTD 2018. The increase in G&A expense can be attributed to the additional costs and staff associated with the Strategic Combination. A change in accounting for lease contracts resulted in a $1.4 million reduction in G&A in YTD 2019 relative to YTD 2018. Per unit G&A expense was lower in Q2/2019 and YTD 2019 relative to the same periods of 2018 as we were able to realize efficiencies by combining the two organizations.

G&A expense for YTD 2019 is slightly higher than our expectation due to severance costs associated with a reduction in staffing levels. We expect G&A expense for 2019 to be in line with our annual guidance of approximately $46 million ($1.30/boe).

Financing and Interest Expense

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

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

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2019**	2018	Change	**2019**	2018	Change
Interest on bank loan	**$ 5,109**	$ 3,260	$ 1,849	**$ 10,521**	$ 6,189	$ 4,332
Interest on long-term notes	**22,825**	22,270	555	**45,427**	43,852	1,575
Interest on lease obligations	**158**	—	158	**328**	—	328
Cash interest	**28,092**	25,530	2,562	**56,276**	50,041	6,235
Accretion of debt issue costs	**1,051**	934	117	**2,146**	2,125	21
Accretion of asset retirement obligations	**3,398**	2,322	1,076	**6,861**	4,630	2,231
Financing and interest expense	**$ 32,541**	$ 28,786	$ 3,755	**$ 65,283**	$ 56,796	$ 8,487
Cash interest per boe	**$ 3.14**	$ 3.97	$ (0.83)	**$ 3.12**	$ 3.94	$ (0.82)
Financing and interest expense per boe	**$ 3.63**	$ 4.48	$ (0.85)	**$ 3.62**	$ 4.48	$ (0.86)

Financing and interest expense was $32.5 million in Q2/2019 and $65.3 million for YTD 2019 compared to $28.8 million in Q2/2018 and $56.8 million in YTD 2018. Interest on our bank loan of $5.1 million in Q2/2019 and $10.5 million in YTD 2019 was higher than $3.3 million in Q2/2018 and $6.2 million in YTD 2019 due to the increase in loan balances following the assumption of net debt associated with the Strategic Combination. The weighted average interest rate on our bank loan was 3.6% in YTD 2019 compared to 4.5% in YTD 2018. The reported amount of interest on our long-term notes was higher in both periods of 2019 as the exchange rate used to convert the interest on our U.S. dollar denominated long-term notes was higher relative to the comparative periods of 2018. Accretion of our asset retirement obligations was higher in Q2/2019 and YTD 2019 as our asset retirement obligation increased with the Strategic Combination. Cash interest expense of $56.3 million or $3.12/boe for YTD 2019 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 $4.7 million for Q2/2019 and $6.5 million for YTD 2019 is higher than $1.4 million for Q2/2018 and $3.4 million for YTD 2018 primarily due to a higher amount of acreage expiring in Q2/2019 relative to the same period of 2018.

Depletion and Depreciation

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

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2019**	2018	Change	**2019**	2018	Change
Depletion	**$ 185,232**	$ 111,035	$ 74,197	**$ 370,076**	$ 218,813	$ 151,263
Depreciation	**540**	829	(289)	**1,050**	1,340	(290)
Depletion and depreciation	**$ 185,772**	$ 111,864	$ 73,908	**$ 371,126**	$ 220,153	$ 150,973
Depletion and depreciation per boe	**$ 20.75**	$ 17.40	$ 3.35	**$ 20.56**	$ 17.35	$ 3.21

Depletion and depreciation expense was $185.8 million ($20.75/boe) for Q2/2019 and $371.1 million ($20.56/boe) for YTD 2019 compared to $111.9 million ($17.40/boe) for Q2/2018 and $220.2 million ($17.35/boe) for YTD 2018. Total depletion and depreciation expense was higher in both periods of 2019 due to the Strategic Combination which resulted in a higher depletable base and production relative to the comparative periods of 2018. The depletion rate per boe increased following the Strategic Combination due to the addition of proved plus probable reserves at a higher cost than our historic base and resulted in the depletion rate of $20.75/boe for Q2/2019 and $20.56/boe for YTD 2019 which was higher than $17.40/boe for Q2/2018 and $17.35/boe for YTD 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 $5.0 million for Q2/2019 and $10.8 million for YTD 2019 compared to $3.9 million for Q2/2018 and $7.8 million for YTD 2018. SBC expense is higher in 2019 relative to 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 functional currency entities.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for exchange rates)	**2019**	2018	Change	**2019**	2018	Change
Unrealized foreign exchange (gain) loss	**$ (25,318)**	$ 22,673	$ (47,991)	**$ (52,259)**	$ 58,719	$ (110,978)
Realized foreign exchange loss	**639**	2,076	(1,437)	**44**	2,247	(2,203)
Foreign exchange (gain) loss	**$ (24,679)**	$ 24,749	$ (49,428)	**$ (52,215)**	$ 60,966	$ (113,181)
CAD/USD exchange rates:						
At beginning of period	**1.3360**	1.2901		**1.3646**	1.2518	
At end of period	**1.3091**	1.3142		**1.3091**	1.3142	

We recorded an unrealized foreign exchange gain of $25.3 million for Q2/2019 and $52.3 million for YTD 2019 due to a strengthening of the Canadian dollar relative to the U.S. dollar. The CAD/USD exchange rate was 1.3091 CAD/USD at June 30, 2019 compared to 1.3360 CAD/USD at March 31, 2019 and 1.3646 CAD/USD at December 31, 2018. We recorded an unrealized foreign exchange loss of $22.7 million in Q2/2018 and $58.7 million in YTD 2018 as the CAD/USD exchange rate weakened to 1.3142 CAD/USD at June 30, 2018 from 1.2901 CAD/USD at March 31, 2018 and 1.2518 CAD/USD 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 loss of $0.6 million for Q2/2019 and $0.04 million for YTD 2019 compared to a loss of $2.1 million for Q2/2018 and $2.2 million for YTD 2018.

Income Taxes

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2019**	2018	Change	**2019**	2018	Change
Current income tax expense (recovery)	**$ 495**	$ 2	$ 493	**$ 1,090**	$ (71)	$ 1,161
Deferred income tax recovery	**(1,555)**	(24,561)	23,006	**(16,040)**	(47,478)	31,438
Total income tax recovery	**$ (1,060)**	$ (24,559)	$ 23,499	**$ (14,950)**	$ (47,549)	$ 32,599

Current income tax expense was $0.5 million for Q2/2019 and $1.1 million for YTD 2019 compared to the nominal amounts recorded for Q2/2018 and YTD 2018. The current income tax expense for Q2/2019 and YTD 2019 reflects state taxes owing on our U.S. operations.

We recorded a deferred income tax recovery of $1.6 million for Q2/2019 and $16.0 million for YTD 2019 as compared to $24.6 million for Q2/2018 and $47.5 million for YTD 2018. The deferred income tax recoveries in both periods decreased because the effect of the Alberta tax rate reduction was more than offset by the increase in adjusted funds flow and the decrease 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 and six months ended June 30, 2019 and 2018 are set forth in the following table.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2019**	2018	Change	**2019**	2018	Change
Petroleum and natural gas sales	**$ 482,000**	$ 347,605	$ 134,395	**$ 935,424**	$ 633,672	$ 301,752
Royalties	**(86,617)**	(77,205)	(9,412)	**(167,942)**	(142,044)	(25,898)
Revenue, net of royalties	**395,383**	270,400	124,983	**767,482**	491,628	275,854
Expenses						
Operating	**(100,474)**	(70,149)	(30,325)	**(200,766)**	(136,037)	(64,729)
Transportation	**(11,869)**	(7,836)	(4,033)	**(25,199)**	(16,355)	(8,844)
Blending and other	**(20,890)**	(18,239)	(2,651)	**(37,678)**	(35,529)	(2,149)
Operating netback	**$ 262,150**	$ 174,176	$ 87,974	**$ 503,839**	$ 303,707	$ 200,132
General and administrative	**(11,506)**	(10,563)	(943)	**(25,642)**	(21,571)	(4,071)
Cash financing and interest	**(28,092)**	(25,530)	(2,562)	**(56,276)**	(50,041)	(6,235)
Realized financial derivatives gain (loss)	**12,993**	(29,408)	42,401	**31,807**	(39,249)	71,056
Realized foreign exchange (loss) gain	**(639)**	(2,076)	1,437	**(44)**	(2,247)	2,203
Other income	**1,719**	288	1,431	**4,306**	567	3,739
Current income tax (expense) recovery	**(495)**	(2)	(493)	**(1,090)**	71	(1,161)
Payments on onerous contracts	**—**	(195)	195	**—**	(292)	292
Adjusted funds flow	**$ 236,130**	$ 106,690	$ 129,440	**$ 456,900**	$ 190,945	$ 265,955
Exploration and evaluation	**(4,685)**	(1,358)	(3,327)	**(6,529)**	(3,377)	(3,152)
Depletion and depreciation	**(185,772)**	(111,864)	(73,908)	**(371,126)**	(220,153)	(150,973)
Share based compensation	**(5,001)**	(3,915)	(1,086)	**(10,844)**	(7,830)	(3,014)
Non-cash financing and accretion	**(4,449)**	(3,256)	(1,193)	**(9,007)**	(6,755)	(2,252)
Unrealized financial derivatives gain (loss)	**14,673**	(47,385)	62,058	**(38,588)**	(65,094)	26,506
Unrealized foreign exchange gain (loss)	**25,318**	(22,673)	47,991	**52,259**	(58,719)	110,978
Gain on disposition of oil and gas properties	**1,057**	244	813	**1,057**	1,730	(673)
Deferred income tax recovery	**1,555**	24,561	(23,006)	**16,040**	47,478	(31,438)
Payments on onerous contracts	**—**	195	(195)	**—**	292	(292)
Net income (loss) for the period	**$ 78,826**	$ (58,761)	$ 137,587	**$ 90,162**	$ (121,483)	$ 211,645

We generated adjusted funds flow of $236.1 million for Q2/2019 and $456.9 million for YTD 2019 which is an increase of $129.4 million and $266.0 million from the comparative periods of 2018. The increase in adjusted funds flow was primarily due to higher operating netback which was $88.0 million higher in Q2/2019 and $200.1 million higher in YTD 2019 relative to the same periods of 2018. The increase in operating netback was driven by increased production as a result of the Strategic Combination. We recorded realized hedging gains of $13.0 million in Q2/2019 and $31.8 million in YTD 2019 compared to realized losses of $29.4 million and $39.2 million in the same periods in 2018 which also contributed to the increase in adjusted funds flow.

In Q2/2019 we reported net income of $78.8 million compared to a net loss of $58.8 million in Q2/2018. In addition to the $129.4 million increase in adjusted funds flow in Q2/2019 compared to Q2/2018, unrealized gains on financial derivatives and foreign exchange exceeded losses in Q2/2018 by $110.0 million. This was offset by depletion and depreciation expense that was $73.9 million higher in Q2/2019 compared to Q2/2018. Our deferred tax recovery of $1.6 million for Q2/2019 was $23.0 million lower than $24.6 million for Q2/2018 due to higher net income before income tax which was partially offset by a $10.6 million recovery associated with a reduction in future tax rates in Alberta.

For YTD 2019 we reported net income of $90.2 million compared to a net loss of $121.5 million in YTD 2018. The increase in net income was driven by the $266.0 million increase in adjusted funds flow and by unrealized gains and losses on financial derivatives and foreign exchange which increased net income $137.5 million in YTD 2019 compared to YTD 2018. These increases to net income were offset by an increase in depletion and depreciation expense of $151.0 million. Our deferred tax recovery was $31.4 million lower in YTD 2019 relative to YTD 2018 due to the increase in net income before income tax which was partially offset by a $10.6 million recovery associated with a reduction in future tax rates in Alberta.

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 foreign currency translation loss of $45.4 million for Q2/2019 and $93.2 million for YTD 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 both periods. The CAD/USD exchange rate was 1.3091 CAD/USD as at June 30, 2019 compared to 1.3360 CAD/USD at March 31, 2019 and 1.3646 CAD/USD as at December 31, 2018.

Capital Expenditures

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

	Three Months Ended June 30					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 54,056**	**$ 35,926**	**$ 89,982**	$ 9,193	$ 45,945	$ 55,138
Facilities	**8,527**	**1,920**	**10,447**	19,378	2,175	21,553
Land, seismic and other	**5,676**	**141**	**5,817**	2,037	102	2,139
Total exploration and development	**$ 68,259**	**$ 37,987**	**$ 106,246**	$ 30,608	$ 48,222	$ 78,830
Total acquisitions and property swaps, net of proceeds from divestitures	**$ 1,647**	**$ —**	**$ 1,647**	$ (21)	$ —	$ (21)

	Six Months Ended June 30					
	2019			2018		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**142,937**	**81,985**	**224,922**	42,736	81,116	123,852
Facilities	**21,467**	**4,582**	**26,049**	32,368	9,013	41,381
Land, seismic and other	**8,725**	**393**	**9,118**	7,029	102	7,131
Total exploration and development	**$ 173,129**	**$ 86,960**	**$ 260,089**	$ 82,133	$ 90,231	$ 172,364
Total acquisitions and property swaps, net of proceeds from divestitures	**$ 1,647**	**$ —**	**$ 1,647**	$ (2,047)		$ (2,047)

Exploration and development expenditures were $106.2 million for Q2/2019 and $260.1 million for YTD 2019 compared to $78.8 million for Q2/2018 and $172.4 million for YTD 2018. Higher exploration and development expenditures in Q2/2019 and YTD 2019 relative to the same periods of 2018 reflects the additional activity associated with our Viking and Duvernay light oil properties which were acquired during Q3/2018 as part of the Strategic Combination.

In Canada, we invested $68.3 million on exploration and development activities in Q2/2019 which is $37.7 million higher than $30.6 million in Q2/2018. Exploration and development expenditures for Q2/2019 included costs associated with drilling 43 (42.9 net) light oil wells, 4 (4.0 net) heavy oil wells and investing $8.5 million on facilities. Exploration and development expenditures of $173.1 million for YTD 2019 included costs associated with drilling 141 (121.2 net) light oil wells, 5 (5.0 net) heavy oil wells and 4 (4.0 net) stratigraphic exploration wells along with $21.5 million of associated facility expenditures. Total exploration and development costs for YTD 2019 were $91.0 million higher than the same period of 2018 primarily due to the investment on our Viking and Duvernay light oil properties which were acquired in Q3/2018.

Total U.S. exploration and development expenditures were $38.0 million for Q2/2019, $10.2 million lower than $48.2 million for Q2/2018. The decrease in Q2/2019 is primarily a result of lower completion activity on our lands relative to Q2/2018. During Q2/2019 we participated in the drilling of 20 (5.1 net) wells and commenced production from 29 (5.0 net) wells compared to 18 (2.6 net) wells drilled and 32 (7.6 net) wells on production during Q2/2018. Exploration and development expenditures of $87.0 million for YTD 2019 include costs associated with drilling 43 (9.2 net) wells and bringing 65 (13.9 net) wells on production which is slightly lower than exploration and development expenditures of $90.2 million in YTD 2018 when we drilled 43 (9.5 net) well and commenced production from 59 (13.1 net) wells.

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

We have narrowed our 2019 annual guidance range and we expect to invest between $550 million and $600 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 June 30, 2019, our capital structure was comprised of shareholders' capital, long-term notes, working capital and our bank loan.

The capital intensive nature of our operations requires us to maintain adequate sources of liquidity to fund ongoing exploration and development. Our capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties. We believe that our internally generated adjusted funds flow and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures. Adjusted funds flow depends on a number of factors, including commodity prices, production and sales volumes, royalties, operating expenses, taxes and foreign exchange rates. In order to manage our capital structure and liquidity, we may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

Management of debt levels is a priority for Baytex in order to sustain operations and support our plans for long-term growth. At June 30, 2019, net debt was $2,028.7 million, a decrease of $236.5 million from net debt of $2,265.2 million at December 31, 2018. The decrease in net debt is primarily a result of adjusted funds flow exceeding exploration and development expenditures for YTD 2019 by $196.8 million. Net debt was also lower at June 30, 2019 due to a strengthening of the Canadian dollar which resulted in a $52.7 million decrease in the reported principal amount of our U.S. dollar denominated long-term notes relative to December 31, 2018.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio calculated on a twelve month trailing basis. At June 30, 2019, our net debt to adjusted funds flow ratio was 2.3, 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 $236.5 million lower at June 30, 2019.

On July 31, 2019, the Board of Directors approved the early redemption of the US $150 million principal amount of 6.75% senior unsecured notes which were issued on February 17, 2011. We will provide notice to the bondholders and expect to redeem the notes in September 2019.

Bank Loan

At June 30, 2019, the principal amount of bank loan and letters of credit outstanding was $429.9 million and we had approximately $622.8 million of undrawn capacity under our credit facilities that total approximately $1.05 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 16, 2019).

The weighted average interest rate on the credit facilities for Q2/2019 was 3.5% and 3.6% for YTD 2019 compared to 4.1% for Q2/2018 and 4.5% for YTD 2018.

Financial Covenants

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

Covenant Description	Position as at June 30, 2019	Covenant
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.47:1.00**	3.50:1.00
Interest Coverage(3) (Minimum Ratio)	**8.24:1.00**	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 June 30, 2019, the Company's Senior Secured Debt totaled $429.9 million which includes $414.7 million of principal amounts outstanding and $15.2 million of letters of credit.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, 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 June 30, 2019 was $911.1 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 June 30, 2019 were $110.6 million.

Long-Term Notes

We have four series of long-term notes outstanding that total $1.54 billion as at June 30, 2019. The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts our ability to raise additional debt beyond existing credit facilities and long-term notes unless we maintain a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA to financing and interest expenses on a trailing twelve month basis) of 2.50:1.00. The fixed charge coverage ratio was 8.24:1.00 as at June 30, 2019.

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 anytime prior to maturity. On July 31, 2019, the Board of Directors approved the early redemption of these notes. We will provide notice to the bondholders and expect to redeem the notes in September 2019.

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

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the "5.125% Notes") and US$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"). The 5.125% Notes and the 5.625% Notes pay interest semi-annually with the principal amount repayable at maturity. The 5.125% Notes are redeemable at our option, in whole or in part, at par anytime prior to maturity. As of June 1, 2019, the 5.625% Notes are redeemable at our option, in whole or in part, at specified redemption prices and will be redeemable at par from June 1, 2022 to maturity.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the six months ended June 30, 2019, we issued 2.7 million common shares pursuant to our share-based compensation program. As at July 31, 2019, we had 557.9 million common shares issued and outstanding and no preferred shares issued and outstanding.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact our adjusted funds flow in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of June 30, 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	**$ 227,717**	$ 227,717	$ —	$ —	$ —
Bank loan(1) (2)	**414,691**	—	414,691	—	—
Long-term notes(2)	**1,543,645**	—	720,005	823,640	—
Interest on long-term notes(3)	**278,978**	89,421	131,899	57,658	—
Lease agreements	**15,938**	6,108	9,549	281	—
Processing agreements	**46,408**	12,269	13,271	9,052	11,816
Transportation agreements	**103,327**	17,603	37,312	17,621	30,791
Total	**$ 2,630,704**	$ 353,118	$ 1,326,727	$ 908,252	$ 42,607

(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

($ thousands, except per common share amounts)	2019 Q2	2019 Q1	2018 Q4	2018 Q3	2018 Q2	2018 Q1	2017 Q4	2017 Q3
Petroleum and natural gas sales	**482,000**	453,424	358,437	436,761	347,605	286,067	303,163	258,620
Net income (loss)	**78,826**	11,336	(231,238)	27,412	(58,761)	(62,722)	76,038	(9,228)
Per common share - basic	**0.14**	0.02	(0.42)	0.07	(0.25)	(0.27)	0.32	(0.04)
Per common share - diluted	**0.14**	0.02	(0.42)	0.07	(0.25)	(0.27)	0.32	(0.04)
Adjusted funds flow	**236,130**	220,770	110,828	171,210	106,690	84,255	105,796	77,340
Per common share - basic	**0.42**	0.40	0.20	0.46	0.45	0.36	0.45	0.33
Per common share - diluted	**0.42**	0.40	0.20	0.45	0.45	0.36	0.44	0.33
Exploration and development	**106,246**	153,843	184,162	139,195	78,830	93,534	90,156	61,544
Canada	**68,259**	104,870	125,507	94,477	30,608	51,525	41,864	14,487
U.S.	**37,987**	48,973	58,655	44,718	48,222	42,009	48,292	47,057
Acquisitions, net of divestitures	**1,647**	—	183	46	(21)	(2,026)	(3,937)	(7,436)
Net debt	**2,028,686**	2,175,241	2,265,167	2,112,090	1,784,835	1,783,379	1,734,284	1,748,805
Total assets	**6,222,190**	6,359,157	6,377,198	6,491,303	4,476,906	4,433,074	4,372,111	4,353,637
Common shares outstanding	**556,798**	555,872	554,060	553,950	236,662	236,578	235,451	235,451
Daily production								
Total production (boe/d)	**98,402**	101,115	98,890	82,412	70,664	69,522	69,556	69,310
Canada (boe/d)	**58,580**	60,018	60,453	45,214	34,042	33,505	32,194	34,560
U.S. (boe/d)	**39,822**	41,097	38,437	37,198	36,622	36,017	37,362	34,750
Benchmark prices								
WTI oil (US$/bbl)	**59.81**	54.90	58.81	69.50	67.88	62.87	55.40	48.20
WCS heavy (US$/bbl)	**49.14**	42.61	19.39	47.25	48.61	38.59	43.14	38.26
CAD/USD avg exchange rate	**1.3376**	1.3293	1.3215	1.307	1.2911	1.2651	1.2717	1.2524
AECO gas ($/mcf)	**1.17**	1.94	1.94	1.35	1.03	1.85	1.96	2.04
NYMEX gas (US$/mmbtu)	**2.64**	3.15	3.64	2.90	2.80	3.00	2.93	3.00
Sales price ($/boe)	**51.49**	47.98	37.89	55.03	51.22	42.96	44.75	38.04
Royalties ($/boe)	**(9.67)**	(8.94)	(8.77)	(12.13)	(12.01)	(10.36)	(10.86)	(8.65)
Operating expense ($/boe)	**(11.22)**	(11.02)	(10.76)	(10.25)	(10.91)	(10.53)	(10.91)	(10.10)
Transportation expense ($/boe)	**(1.33)**	(1.46)	(1.21)	(1.26)	(1.22)	(1.36)	(1.20)	(1.46)
Operating netback ($/boe)	**29.27**	26.56	17.15	31.39	27.08	20.71	21.78	17.83
Financial derivatives gain (loss) ($/boe)	**1.45**	2.07	(0.34)	(4.07)	(4.57)	(1.57)	0.30	0.44
Operating netback after financial derivatives ($/boe)	**30.72**	28.63	16.81	27.32	22.51	19.14	22.08	18.27

In Q2/2019 we delivered our third consecutive quarter of strong operating and financial results following closing of the Strategic Combination in Q3/2018. Over the last eight quarters, production has increased from 69,310 boe/d during Q3/2017 to 98,402 boe/d in Q2/2019 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, our exploration and development program was focused on our heavy oil properties at Peace River and Lloydminster. Exploration and development activity in Canada increased following the Strategic Combination with the addition of our light oil Viking and Duvernay properties.

Global benchmark prices for crude oil have fluctuated as attempts to balance the market with production cuts and increased demand have been mitigated by geopolitical factors and increasing production in North America. We received the strongest realized pricing in our Canadian operations for the eight most recent quarters after a narrowing of light and heavy oil differentials and a higher weighting of light oil production following the Strategic Combination. The WCS benchmark averaged US$49.14/bbl in Q2/2019 compared to US $19.39/bbl in Q4/2018 and US$38.26/bbl in Q3/2017.

Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow began to improve in late 2017 as commodity prices recovered and increased through Q2/2019 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 $236.1 million in Q2/2019 which is higher than $77.3 million reported in Q3/2017.

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 $1,748.8 million at Q3/2017 to $2,028.7 million at Q2/2019 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 June 30, 2019, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

There have been no changes in our critical accounting estimates in the six months ended June 30, 2019 except for the adoption of IFRS 16 as discussed below. Further information on our critical accounting policies and estimates can be found in the notes to the audited annual consolidated financial statements and MD&A for the year ended December 31, 2018.

CHANGES IN ACCOUNTING STANDARDS

Leases

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

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

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

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease obligation and corresponding right-of-use asset ("lease asset") are recognized at the commencement of the lease. The present value of the lease obligation is based on the future lease payments and is discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. The Company uses a single discount rate for a portfolio of 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 June 30		Six Months Ended June 30	
($ thousands)	**2019**	2018	**2019**	2018
Cash flow from operating activities	**$ 247,585**	$ 74,538	**$ 404,950**	$ 162,150
Change in non-cash working capital	**(16,253)**	29,228	**42,224**	22,608
Asset retirement obligations settled	**4,798**	2,924	**9,726**	6,187
Adjusted funds flow	**$ 236,130**	$ 106,690	**$ 456,900**	$ 190,945

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 June 30		Six Months Ended June 30	
($ thousands)	**2019**	2018	**2019**	2018
Cash flow used in investing activities	**$ 109,596**	$ 73,411	**$ 297,184**	$ 157,107
Change in non-cash working capital	**(1,389)**	5,905	**(35,069)**	13,717
Proceeds from disposition of oil an gas properties	**950**	21	**950**	2,234
Property acquisitions	**(2,073)**	—	**(2,073)**	(187)
Property swaps	**(524)**	—	**(524)**	—
Additions to other plant and equipment	**(314)**	(507)	**(379)**	(507)
Exploration and development expenditures	**$ 106,246**	$ 78,830	**$ 260,089**	$ 172,364

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)	**June 30, 2019**	December 31, 2018
Bank loan[(1)]	**$ 414,691**	$ 522,294
Long-term notes[(1)]	**1,543,645**	1,596,323
Trade and other payables	**227,717**	258,114
Trade and other receivables	**(157,367)**	(111,564)
Net debt	**$ 2,028,686**	$ 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 June 30		Six Months Ended June 30	
($ thousands)	**2019**	2018	**2019**	2018
Petroleum and natural gas sales	**$ 482,000**	$ 347,605	**$ 935,424**	$ 633,672
Blending and other expense	**(20,890)**	(18,239)	**(37,678)**	(35,529)
Total sales, net of blending and other expense	**461,110**	329,366	**897,746**	598,143
Royalties	**(86,617)**	(77,205)	**(167,942)**	(142,044)
Operating expense	**(100,474)**	(70,149)	**(200,766)**	(136,037)
Transportation expense	**(11,869)**	(7,836)	**(25,199)**	(16,355)
Operating netback	**262,150**	174,176	**503,839**	303,707
Realized financial derivative gain (loss)	**12,993**	(29,408)	**31,807**	(39,249)
Operating netback after realized financial derivatives	**$ 275,143**	$ 144,768	**$ 535,646**	$ 264,458

Bank EBITDA

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

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2019**	2018	**2019**	2018
Net income (loss)	**$ 78,826**	$ (58,761)	**$ 90,162**	$ (121,483)
Plus:				
Financing and interest	**32,541**	28,786	**65,283**	56,796
Unrealized foreign exchange (gain) loss	**(25,318)**	22,673	**(52,259)**	58,719
Unrealized financial derivatives (gain) loss	**(14,673)**	47,385	**38,588**	65,094
Current income tax expense (recovery)	**495**	2	**1,090**	(71)
Deferred income tax recovery	**(1,555)**	(24,561)	**(16,040)**	(47,478)
Depletion and depreciation	**185,772**	111,864	**371,126**	220,153
Gain on disposition of oil and gas properties	**(1,057)**	(244)	**(1,057)**	(1,730)
Payments on lease obligations	**(1,623)**	—	**(3,012)**	—
Non-cash items[1]	**9,686**	5,273	**17,373**	11,207
Bank EBITDA	**$ 263,094**	$ 132,417	**$ 511,254**	$ 241,207

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

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended June 30, 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.

The assets previously held by Raging River contributed revenues net of royalties of $127.6 million for Q2/2019 and $251.1 million for YTD 2019. At June 30, 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; 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; the existence, operation and strategy of our risk management program; that management of our debt levels is a priority; that we intend to redeem the US$150 million principal amount of 6.75% notes in September 2019; 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	**June 30, 2019**	December 31, 2018
ASSETS			
Current assets			
Trade and other receivables		**$ 157,367**	$ 111,564
Financial derivatives	18	**37,916**	79,582
		195,283	191,146
Non-current assets			
Financial derivatives	18	**3,350**	—
Exploration and evaluation assets	5	**341,034**	358,935
Oil and gas properties	6	**5,658,935**	5,817,889
Other plant and equipment		**8,557**	9,228
Lease assets	3	**15,031**	—
		$ 6,222,190	$ 6,377,198
LIABILITIES			
Current liabilities			
Trade and other payables		**$ 227,717**	$ 258,114
Financial derivatives	18	**272**	—
Lease obligations	3, 9	**5,622**	—
Onerous contracts	3	**—**	1,986
		233,611	260,100
Non-current liabilities			
Bank loan	7	**413,087**	520,700
Long-term notes	8	**1,532,515**	1,583,240
Lease obligations	3, 9	**9,462**	—
Asset retirement obligations	10	**681,076**	646,898
Deferred income tax liability		**289,198**	310,836
		3,158,949	3,321,774
SHAREHOLDERS' EQUITY			
Shareholders' capital	11	**5,711,889**	5,701,516
Contributed surplus		**19,608**	19,137
Accumulated other comprehensive income		**574,685**	667,874
Deficit		**(3,242,941)**	(3,333,103)
		3,063,241	3,055,424
		$ 6,222,190	$ 6,377,198

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

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

		Three Months Ended June 30		Six Months Ended June 30	
	Notes	**2019**	2018	**2019**	2018
Revenue, net of royalties					
Petroleum and natural gas sales	12	**$ 482,000**	$ 347,605	**$ 935,424**	$ 633,672
Royalties		**(86,617)**	(77,205)	**(167,942)**	(142,044)
		395,383	270,400	**767,482**	491,628
Expenses					
Operating		**100,474**	70,149	**200,766**	136,037
Transportation		**11,869**	7,836	**25,199**	16,355
Blending and other		**20,890**	18,239	**37,678**	35,529
General and administrative		**11,506**	10,563	**25,642**	21,571
Exploration and evaluation	5	**4,685**	1,358	**6,529**	3,377
Depletion and depreciation		**185,772**	111,864	**371,126**	220,153
Share-based compensation	13	**5,001**	3,915	**10,844**	7,830
Financing and interest	16	**32,541**	28,786	**65,283**	56,796
Financial derivatives (gain) loss	18	**(27,666)**	76,793	**6,781**	104,343
Foreign exchange (gain) loss	17	**(24,679)**	24,749	**(52,215)**	60,966
Gain on disposition of oil and gas properties		**(1,057)**	(244)	**(1,057)**	(1,730)
Other income		**(1,719)**	(288)	**(4,306)**	(567)
		317,617	353,720	**692,270**	660,660
Net income (loss) before income taxes		**77,766**	(83,320)	**75,212**	(169,032)
Income tax expense (recovery)	15				
Current income tax expense (recovery)		**495**	2	**1,090**	(71)
Deferred income tax recovery		**(1,555)**	(24,561)	**(16,040)**	(47,478)
		(1,060)	(24,559)	**(14,950)**	(47,549)
Net income (loss)		**$ 78,826**	$ (58,761)	**$ 90,162**	$ (121,483)
Other comprehensive income (loss)					
Foreign currency translation adjustment		**(45,395)**	44,134	**(93,189)**	116,456
Comprehensive income (loss)		**$ 33,431**	$ (14,627)	**$ (3,027)**	$ (5,027)
Net income (loss) per common share	14				
Basic		**$ 0.14**	$ (0.25)	**$ 0.16**	$ (0.51)
Diluted		**$ 0.14**	$ (0.25)	**$ 0.16**	$ (0.51)
Weighted average common shares (000's)	14				
Basic		**556,599**	236,628	**556,022**	236,472
Diluted		**560,685**	236,628	**559,972**	236,472

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	8,725	(8,725)	—	—	**—**
Share-based compensation	—	7,830	—	—	**7,830**
Comprehensive income (loss) for the period	—	—	116,456	(121,483)	**(5,027)**
Balance at June 30, 2018	$ 4,452,301	$ 15,104	$ 579,560	$ (3,129,277)	**$ 1,917,688**
Balance at December 31, 2018	$ 5,701,516	$ 19,137	$ 667,874	$ (3,333,103)	**$ 3,055,424**
Vesting of share awards	10,373	(10,373)	—	—	**—**
Share-based compensation	—	10,844	—	—	**10,844**
Comprehensive income (loss) for the period	—	—	(93,189)	90,162	**(3,027)**
Balance at June 30, 2019	$ 5,711,889	$ 19,608	$ 574,685	$ (3,242,941)	**$ 3,063,241**

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 June 30		Six Months Ended June 30	
	Notes	**2019**	2018	**2019**	2018
CASH PROVIDED BY (USED IN):					
Operating activities					
Net income (loss) for the period		**$ 78,826**	$ (58,761)	**$ 90,162**	$ (121,483)
Adjustments for:					
Share-based compensation	13	**5,001**	3,915	**10,844**	7,830
Unrealized foreign exchange (gain) loss	17	**(25,318)**	22,673	**(52,259)**	58,719
Exploration and evaluation	5	**4,685**	1,358	**6,529**	3,377
Depletion and depreciation		**185,772**	111,864	**371,126**	220,153
Non-cash financing and accretion	16	**4,449**	3,256	**9,007**	6,755
Unrealized financial derivatives (gain) loss	18	**(14,673)**	47,385	**38,588**	65,094
Gain on disposition of oil and gas properties		**(1,057)**	(244)	**(1,057)**	(1,730)
Deferred income tax recovery		**(1,555)**	(24,561)	**(16,040)**	(47,478)
Payments on onerous contracts		**—**	(195)	**—**	(292)
Asset retirement obligations settled	10	**(4,798)**	(2,924)	**(9,726)**	(6,187)
Change in non-cash working capital		**16,253**	(29,228)	**(42,224)**	(22,608)
		247,585	74,538	**404,950**	162,150
Financing activities					
Decrease in bank loan		**(136,366)**	(1,127)	**(104,754)**	(5,043)
Payments on lease obligations	9	**(1,623)**	—	**(3,012)**	—
		(137,989)	(1,127)	**(107,766)**	(5,043)
Investing activities					
Additions to exploration and evaluation assets	5	**(269)**	(115)	**(1,394)**	(1,402)
Additions to oil and gas properties	6	**(105,977)**	(78,715)	**(258,695)**	(170,962)
Additions to other plant and equipment		**(314)**	(507)	**(379)**	(507)
Property acquisitions		**(2,073)**	—	**(2,073)**	(187)
Property swaps		**(524)**	—	**(524)**	—
Proceeds from disposition of oil and gas properties		**950**	21	**950**	2,234
Change in non-cash working capital		**(1,389)**	5,905	**(35,069)**	13,717
		(109,596)	(73,411)	**(297,184)**	(157,107)
Change in cash		**—**	—	**—**	—
Cash, beginning of period		**—**	—	**—**	—
Cash, end of period		**$ —**	$ —	**$ —**	$ —
Supplementary information					
Interest paid		**$ 34,143**	$ 30,822	**$ 56,179**	$ 49,698
Income taxes paid		**$ 1,082**	$ —	**$ 1,082**	$ —

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

1. REPORTING ENTITY

Baytex Energy Corp. (the "Company" or "Baytex") is an oil and gas corporation engaged in the acquisition, development and production of oil and natural gas in the Western Canadian Sedimentary Basin and the United States. The Company's common shares are traded on the Toronto Stock Exchange and the New York Stock Exchange under the symbol BTE. The Company's head and principal office is located at 2800, 520 – 3rd Avenue S.W., Calgary, Alberta, T2P 0R3, and its registered office is located at 2400, 525 – 8th Avenue S.W., Calgary, Alberta, T2P 1G1.

2. BASIS OF PRESENTATION

The condensed consolidated interim financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). These consolidated financial statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with the annual consolidated financial statements as at and for the year ended December 31, 2018.

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

The consolidated financial statements have been prepared on a historical cost basis, with the exception of derivative financial instruments which have been measured at fair value. The consolidated financial statements are presented in Canadian dollars which is the functional currency of the Company. All financial information is rounded to the nearest thousand, except per share amounts or when otherwise indicated.

The audited consolidated financial statements of the Company as at and for the year ended December 31, 2018 are available through its filings on SEDAR at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies, critical accounting judgments and significant estimates used in preparation of the 2018 annual financial statements have been applied in the preparation of these consolidated financial statements, except for the adoption of IFRS 16 *Leases* as described below.

Changes in significant accounting policies

Leases

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

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

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

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease obligation and corresponding right-of-use asset ("lease asset") are recognized at the commencement of the lease. The present value of the lease obligation is based on the future lease payments and is discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. The Company uses a single discount rate for a portfolio of 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 June 30	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 294,698**	$ 147,122	**$ 187,302**	$ 200,483	**$ —**	$ —	**$ 482,000**	$ 347,605
Royalties	**(30,936)**	(17,998)	**(55,681)**	(59,207)	**—**	—	**(86,617)**	(77,205)
	263,762	129,124	**131,621**	141,276	**—**	—	**395,383**	270,400
Expenses								
Operating	**73,877**	46,924	**26,597**	23,225	**—**	—	**100,474**	70,149
Transportation	**11,869**	7,836	**—**	—	**—**	—	**11,869**	7,836
Blending and other	**20,890**	18,239	**—**	—	**—**	—	**20,890**	18,239
General and administrative	**—**	—	**—**	—	**11,506**	10,563	**11,506**	10,563
Exploration and evaluation	**4,685**	1,358	**—**	—	**—**	—	**4,685**	1,358
Depletion and depreciation	**116,325**	46,773	**68,907**	64,262	**540**	829	**185,772**	111,864
Share-based compensation	**—**	—	**—**	—	**5,001**	3,915	**5,001**	3,915
Financing and interest	**—**	—	**—**	—	**32,541**	28,786	**32,541**	28,786
Financial derivatives (gain) loss	**—**	—	**—**	—	**(27,666)**	76,793	**(27,666)**	76,793
Foreign exchange (gain) loss	**—**	—	**—**	—	**(24,679)**	24,749	**(24,679)**	24,749
Gain on disposition of oil and gas properties	**(1,057)**	(244)	**—**	—	**—**	—	**(1,057)**	(244)
Other income	**—**	—	**—**	—	**(1,719)**	(288)	**(1,719)**	(288)
	226,589	120,886	**95,504**	87,487	**(4,476)**	145,347	**317,617**	353,720
Net income (loss) before income taxes	**37,173**	8,238	**36,117**	53,789	**4,476**	(145,347)	**77,766**	(83,320)
Income tax expense (recovery)								
Current income tax expense	**—**	—	**495**	2	**—**	—	**495**	2
Deferred income tax (recovery) expense	**(140)**	1,776	**2,014**	4,434	**(3,429)**	(30,771)	**(1,555)**	(24,561)
	(140)	1,776	**2,509**	4,436	**(3,429)**	(30,771)	**(1,060)**	(24,559)
Net income (loss)	**$ 37,313**	$ 6,462	**$ 33,608**	$ 49,353	**$ 7,905**	$ (114,576)	**$ 78,826**	$ (58,761)
Total oil and natural gas capital expenditures[1]	**$ 69,906**	$ 30,587	**$ 37,987**	$ 48,222	**$ —**	$ —	**$ 107,893**	$ 78,809

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

	Canada		U.S.		Corporate		Consolidated	
Six Months Ended June 30	**2019**	2018	**2019**	2018	**2019**	2018	**2019**	2018
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 558,737**	$ 253,937	**$ 376,687**	$ 379,735	**$ —**	$ —	**$ 935,424**	$ 633,672
Royalties	**(56,120)**	(29,332)	**(111,822)**	(112,712)	**—**	—	**(167,942)**	(142,044)
	502,617	224,605	**264,865**	267,023	**—**	—	**767,482**	491,628
Expenses								
Operating	**147,979**	92,344	**52,787**	43,693	**—**	—	**200,766**	136,037
Transportation	**25,199**	16,355	**—**	—	**—**	—	**25,199**	16,355
Blending and other	**37,678**	35,529	**—**	—	**—**	—	**37,678**	35,529
General and administrative	**—**	—	**—**	—	**25,642**	21,571	**25,642**	21,571
Exploration and evaluation	**6,529**	3,377	**—**	—	**—**	—	**6,529**	3,377
Depletion and depreciation	**231,345**	93,431	**138,731**	125,382	**1,050**	1,340	**371,126**	220,153
Share-based compensation	**—**	—	**—**	—	**10,844**	7,830	**10,844**	7,830
Financing and interest	**—**	—	**—**	—	**65,283**	56,796	**65,283**	56,796
Financial derivatives loss	**—**	—	**—**	—	**6,781**	104,343	**6,781**	104,343
Foreign exchange (gain) loss	**—**	—	**—**	—	**(52,215)**	60,966	**(52,215)**	60,966
Gain on disposition of oil and gas properties	**(1,057)**	(1,730)	**—**	—	**—**	—	**(1,057)**	(1,730)
Other income	**—**	—	**—**	—	**(4,306)**	(567)	**(4,306)**	(567)
	447,673	239,306	**191,518**	169,075	**53,079**	252,279	**692,270**	660,660
Net income (loss) before income taxes	**54,944**	(14,701)	**73,347**	97,948	**(53,079)**	(252,279)	**75,212**	(169,032)
Income tax expense (recovery)								
Current income tax expense (recovery)	**—**	—	**1,090**	(71)	**—**	—	**1,090**	(71)
Deferred income tax expense (recovery)	**4,108**	(4,331)	**4,708**	6,673	**(24,856)**	(49,820)	**(16,040)**	(47,478)
	4,108	(4,331)	**5,798**	6,602	**(24,856)**	(49,820)	**(14,950)**	(47,549)
Net income (loss)	**$ 50,836**	$ (10,370)	**$ 67,549**	$ 91,346	**$ (28,223)**	$ (202,459)	**$ 90,162**	$ (121,483)
Total oil and natural gas capital expenditures[(1)]	**$ 174,776**	$ 80,086	**$ 86,960**	$ 90,231	**$ —**	$ —	**$ 261,736**	$ 170,317

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

As at	**June 30, 2019**	December 31, 2018
Canadian assets	**$ 3,759,690**	$ 3,739,029
U.S. assets	**2,453,943**	2,628,941
Corporate assets	**8,557**	9,228
Total consolidated assets	**$ 6,222,190**	$ 6,377,198

5. EXPLORATION AND EVALUATION ASSETS

	June 30, 2019	December 31, 2018
Balance, beginning of period	**$ 358,935**	$ 272,974
Capital expenditures	**1,394**	10,567
Corporate acquisition	**—**	97,858
Property acquisitions	**1,473**	514
Divestitures	**—**	(1,021)
Property swaps	**417**	—
Exploration and evaluation expense	**(6,529)**	(21,729)
Transfer to oil and gas properties	**(8,611)**	(13,866)
Foreign currency translation	**(6,045)**	13,638
Balance, end of period	**$ 341,034**	$ 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	258,695	—	258,695
Property acquisitions	1,171	—	1,171
Transfers from exploration and evaluation assets	8,611	—	8,611
Change in asset retirement obligations (note 10)	39,889	—	39,889
Divestitures	(2,069)	1,690	(379)
Property swaps	(5,754)	4,694	(1,060)
Foreign currency translation	(168,190)	71,290	(96,900)
Depletion	—	(368,981)	(368,981)
Balance, June 30, 2019	**$ 10,876,886**	**$ (5,217,951)**	**$ 5,658,935**

7. BANK LOAN

	June 30, 2019	December 31, 2018
Bank loan - U.S. dollar denominated[(1)]	**$ 25,201**	$ 122,388
Bank loan - Canadian dollar denominated	**389,490**	399,906
Bank loan - principal	**414,691**	522,294
Unamortized debt issuance costs	**(1,604)**	(1,594)
Bank loan	**$ 413,087**	$ 520,700

(1) U.S. dollar denominated bank loan balance was US$19.3 million as at June 30, 2019 (December 31, 2018 - US$89.7 million).

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

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

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

The Credit Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The Credit Facilities contain standard commercial covenants in addition to the financial covenants detailed below. There are no mandatory principal payments required prior to maturity which could be extended upon Baytex's request. Advances (including letters of credit) under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank’s prime lending rate, bankers’ acceptance discount rates or London Interbank Offered Rates, plus applicable margins. In the event that Baytex breaches any of the covenants under the Credit Facilities, Baytex may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to shareholders.

At June 30, 2019, Baytex had $15.2 million of outstanding letters of credit (December 31, 2018 - $14.6 million) under the Credit Facilities.

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

Covenant Description	**Position as at June 30, 2019**	**Covenant**
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.47:1.00**	**3.50:1.00**
Interest Coverage(3) (Minimum Ratio)	**8.24:1.00**	**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 June 30, 2019, the Company's Senior Secured Debt totaled $429.9 million which includes $414.7 million of principal amounts outstanding and $15.2 million of letters of credit.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, 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 June 30, 2019 was $911.1 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 June 30, 2019 were $110.6 million.

8. LONG-TERM NOTES

	June 30, 2019	December 31, 2018
6.75% notes (US$150,000 – principal) due February 17, 2021	**$ 196,365**	$ 204,683
5.125% notes (US$400,000 – principal) due June 1, 2021	**523,640**	545,820
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	**300,000**	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	**523,640**	545,820
Total long-term notes - principal	**1,543,645**	1,596,323
Unamortized debt issuance costs	**(11,130)**	(13,083)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,532,515**	$ 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 June 30, 2019, the fixed charge coverage ratio was 8.24:1.00.

9. LEASE OBLIGATIONS

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

		June 30, 2019
Less than 1 year	**$**	**6,108**
1 - 3 years		**9,549**
3 - 5 years		**281**
After 5 years		**—**
Total lease payments		**15,938**
Amounts representing interest over the term of the lease		**(854)**
Present value of net lease payments		**15,084**
Less current portion of lease obligations		**5,622**
Non-current portion of lease obligations	**$**	**9,462**

The Company recorded interest related to its lease obligations of $0.2 million and $0.3 million for the three and six months ended June 30, 2019. The Company recorded lease payments of $1.6 million and $3.0 million for the three and six months ended June 30, 2019.

10. ASSET RETIREMENT OBLIGATIONS

		June 30, 2019		December 31, 2018
Balance, beginning of period	**$**	**646,898**	$	368,995
Liabilities incurred		**8,985**		12,537
Liabilities settled		**(9,726)**		(14,035)
Liabilities assumed from corporate acquisition		**—**		39,960
Liabilities acquired from property acquisitions		**571**		132
Liabilities divested		**(424)**		(580)
Property swaps		**(1,229)**		—
Accretion (note 16)		**6,861**		10,914
Change in estimate		**—**		33,453
Changes in discount rates and inflation rates[1]		**30,904**		192,672
Foreign currency translation		**(1,764)**		2,850
Balance, end of period	**$**	**681,076**	$	646,898

(1) The discount and inflation rates at June 30, 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 June 30, 2019, no preferred shares have been issued by the Company and all common shares issued were fully paid.

The holders of common shares may receive dividends as declared from time to time and are entitled to one vote per share at any meetings of the holders of common shares. All common shares rank equally with regard to the Company's net assets in the event the Company is wound-up or terminated.

	Number of Common Shares *(000s)*	Amount
Balance, December 31, 2017	**235,451**	**$ 4,443,576**
Vesting of share awards	3,343	19,496
Issued on corporate acquisition	315,266	1,238,995
Issuance costs, net of tax	—	(551)
Balance, December 31, 2018	**554,060**	**$ 5,701,516**
Vesting of share awards	2,738	10,373
Balance, June 30, 2019	**556,798**	**$ 5,711,889**

12. PETROLEUM AND NATURAL GAS SALES

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

	Three Months Ended June 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 141,827**	**$ 153,504**	**$ 295,331**	$ 5,484	$ 161,078	$ 166,562
Heavy oil	**146,038**	**—**	**146,038**	133,768	—	133,768
NGL	**1,757**	**15,808**	**17,565**	4,092	22,794	26,886
Natural gas sales	**5,076**	**17,990**	**23,066**	3,778	16,611	20,389
Total petroleum and natural gas sales	**$ 294,698**	**$ 187,302**	**$ 482,000**	$ 147,122	$ 200,483	$ 347,605

	Six Months Ended June 30					
	2019			2018		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 274,195**	**$ 302,419**	**$ 576,614**	$ 10,336	$ 305,684	$ 316,020
Heavy oil	**263,724**	**—**	**263,724**	225,651	—	225,651
NGL	**5,198**	**36,610**	**41,808**	7,448	40,972	48,420
Natural gas sales	**15,620**	**37,658**	**53,278**	10,502	33,079	43,581
Total petroleum and natural gas sales	**$ 558,737**	**$ 376,687**	**$ 935,424**	$ 253,937	$ 379,735	$ 633,672

Included in accounts receivable at June 30, 2019 is $125.5 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 $5.0 million and $10.8 million for the three and six months ended June 30, 2019 ($3.9 million and $7.8 million for the three and six months ended June 30, 2018).

The weighted average fair value of share awards granted was $2.65 per restricted and performance award for the six months ended June 30, 2019 ($4.17 per restricted and performance award for the six months ended June 30, 2018).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards[(1)]	Total number of share awards
Balance, December 31, 2017	**2,028**	**2,253**	**4,281**
Granted	2,793	2,591	5,384
Assumed on corporate acquisition	302	257	559
Vested and converted to common shares	(1,682)	(1,661)	(3,343)
Forfeited	(198)	(167)	(365)
Balance, December 31, 2018	**3,243**	**3,273**	**6,516**
Granted	3,074	3,124	6,198
Vested and converted to common shares	(1,283)	(1,455)	(2,738)
Forfeited	(243)	(286)	(529)
Balance, June 30, 2019	**4,791**	**4,656**	**9,447**

(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	(856)	6.12
Balance, June 30, 2019	**4,009**	**$ 6.82**

	Options Outstanding			**Options Exercisable**	
Exercise price	Number outstanding at June 30, 2019 (000s)	Weighted average remaining life (years)	Weighted average exercise price	Number exercisable at June 30, 2019 (000s)	Weighted average exercise price
$5.00 - $7.00	2,569	1.08	$ 6.33	1,719	$ 6.41
$7.01 - $9.00	1,440	0.55	7.68	1,154	7.67
Total	**4,009**	**0.89**	**$ 6.82**	**2,873**	**$ 6.92**

14. NET INCOME (LOSS) PER SHARE

Baytex calculates basic income or loss per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income or loss per share amounts reflect the potential dilution that could occur if share awards and share options were converted. The treasury stock method is used to determine the dilutive effect of share awards and share options whereby the potential conversion of share awards and share options and the amount of compensation expense, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the period.

	Three Months Ended June 30					
	2019			2018		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	Net loss	Weighted average common shares (000s)	Net loss per share
Net income (loss) - basic	**$ 78,826**	**556,599**	**$ 0.14**	$ (58,761)	236,628	$ (0.25)
Dilutive effect of share awards	**—**	**4,086**	**—**	—	—	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net income (loss) - diluted	**$ 78,826**	**560,685**	**$ 0.14**	$ (58,761)	236,628	$ (0.25)

	Six Months Ended June 30					
	2019			2018		
	Net income	**Weighted average common shares (000s)**	**Net income per share**	Net loss	Weighted average common shares (000s)	Net loss per share
Net income (loss) - basic	**$ 90,162**	**556,022**	**$ 0.16**	$ (121,483)	236,472	$ (0.51)
Dilutive effect of share awards	**—**	**3,950**	**—**	—	—	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net income (loss) - diluted	**$ 90,162**	**559,972**	**$ 0.16**	$ (121,483)	236,472	$ (0.51)

For the three and six months ended June 30, 2019, no share awards were considered to be anti-dilutive (6.6 million for the three and six months ended June 30, 2018). For the three and six months ended June 30, 2019, 4.0 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 June 30, 2018.

15. INCOME TAXES

The provision for income taxes has been computed as follows:

	Six Months Ended June 30	
	2019	2018
Net income (loss) before income taxes	**$ 75,212**	$ (169,032)
Expected income taxes at the statutory rate of 26.72% (2018 – 27.00%)	**20,097**	(45,639)
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	**2,898**	2,024
Non-taxable portion of foreign exchange (gain) loss	**(7,044)**	8,003
Effect of change in income tax rates	**(10,573)**	—
Effect of rate adjustments for foreign jurisdictions	**(14,427)**	(19,012)
Effect of change in deferred tax benefit not recognized(1)	**(6,532)**	8,003
Adjustments and assessments	**631**	(928)
Income tax recovery	**$ (14,950)**	$ (47,549)

(1) A deferred income tax asset has not been recognized for allowable capital losses of $113 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).

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

As disclosed in the 2018 annual financial statements, Baytex received several reassessments from the Canada Revenue Agency (the “CRA”) in June 2016 which denied $591 million of non-capital loss deductions that Baytex had previously claimed. In September 2016, Baytex filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to our file in July 2018. Baytex remains confident that its original tax filings are correct and intends to defend those tax filings through the appeals process.

16. FINANCING AND INTEREST

	Three Months Ended June 30		Six Months Ended June 30	
	2019	2018	**2019**	2018
Interest on bank loan	**$ 5,109**	$ 3,260	**$ 10,521**	$ 6,189
Interest on long-term notes	**22,825**	22,270	**45,427**	43,852
Interest on lease obligations	**158**	—	**328**	—
Non-cash financing	**1,051**	934	**2,146**	2,125
Accretion on asset retirement obligations (note 10)	**3,398**	2,322	**6,861**	4,630
Financing and interest	**$ 32,541**	$ 28,786	**$ 65,283**	$ 56,796

17. FOREIGN EXCHANGE

	Three Months Ended June 30		Six Months Ended June 30	
	2019	2018	**2019**	2018
Unrealized foreign exchange (gain) loss	**$ (25,318)**	$ 22,673	**$ (52,259)**	$ 58,719
Realized foreign exchange loss	**639**	2,076	**44**	2,247
Foreign exchange (gain) loss	**$ (24,679)**	$ 24,749	**$ (52,215)**	$ 60,966

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, bank loan, long-term notes, and lease obligations. The fair value of the bank loan is equal to the principal and the fair value of the long-term notes is determined based on market prices.

The carrying value and fair value of the Company's financial instruments carried on the consolidated statements of financial position are classified into the following categories:

	June 30, 2019		December 31, 2018		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL[1]					
Financial derivatives	**$ 41,266**	**$ 41,266**	$ 79,582	$ 79,582	Level 2
Total	**$ 41,266**	**$ 41,266**	$ 79,582	$ 79,582	
Financial assets at amortized cost					
Trade and other receivables	**$ 157,367**	**$ 157,367**	$ 111,564	$ 111,564	—
Total	**$ 157,367**	**$ 157,367**	$ 111,564	$ 111,564	
Financial Liabilities					
FVTPL[1]					
Financial derivatives	**$ (272)**	**$ (272)**	$ —	$ —	Level 2
Total	**$ (272)**	**$ (272)**	$ —	$ —	
Financial liabilities at amortized cost					
Trade and other payables	**$ (227,717)**	**$ (227,717)**	$ (258,114)	$ (258,114)	—
Bank loan	**(413,087)**	**(414,691)**	(520,700)	(522,294)	—
Long-term notes	**(1,532,515)**	**(1,522,037)**	(1,583,240)	(1,492,363)	Level 1
Lease obligations	**(15,084)**	**(15,084)**	—	—	—
Total	**$ (2,188,403)**	**$ (2,179,529)**	$ (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 six months ended June 30, 2019 and 2018.

Foreign Currency Risk

The carrying amounts of the Company's U.S. dollar denominated monetary assets and liabilities recorded in entities with a Canadian dollar functional currency at the reporting date are as follows:

	Assets		Liabilities	
	June 30, 2019	December 31, 2018	**June 30, 2019**	December 31, 2018
U.S. dollar denominated	**US$38,934**	US$80,857	**US$957,562**	US$963,351

Interest Rate Risk

Interest Rate Swaps

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

Contract Type	Notional Amount	Maturity Date	Fixed Contract Price	Reference[1]	Fair Value *($ millions)*
Interest rate swap	$100 million	October 2020	2.02%	CDOR	$ (0.3)
Total					**$ (0.3)**
Financial derivatives - Current liability					$ (0.3)

(1) Canadian Dollar Offered Rate.

Commodity Price Risk

Financial Derivative Contracts

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

	Period	Volume	Price/Unit[1]	Index		Fair Value[2] *($ millions)*
Oil						
Basis Swap	Jul 2019 to Sep 2019	4,000 bbl/d	WTI less US$17.38/bbl	WCS	$	(0.7)
Basis Swap	Oct 2019 to Dec 2019	4,000 bbl/d	WTI less US$20.88/bbl	WCS	$	(0.3)
Basis Swap	Jul 2019 to Dec 2019	4,000 bbl/d	WTI less US$8.00/bbl	MSW	$	(0.4)
Fixed - Sell	Jul 2019 to Dec 2019	10,000 bbl/d	US$62.82/bbl	WTI	$	11.2
3-way option[3]	Jul 2019 to Dec 2019	2,000 bbl/d	US$49.00/US$61.70/US$75.00	WTI	$	2.0
3-way option[3]	Jul 2019 to Dec 2019	2,000 bbl/d	US$50.00/US$60.00/US$70.00	WTI	$	1.4
3-way option[3]	Jul 2019 to Dec 2019	1,000 bbl/d	US$55.00/US$65.00/US$72.60	WTI	$	1.3
3-way option[3]	Jul 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$72.50	WTI	$	1.4
3-way option[3]	Jul 2019 to Dec 2019	1,000 bbl/d	US$56.00/US$66.00/US$73.00	WTI	$	1.4
3-way option[3]	Jul 2019 to Dec 2019	2,000 bbl/d	US$57.00/US$67.00/US$73.00	WTI	$	3.0
3-way option[3]	Jul 2019 to Dec 2019	2,000 bbl/d	US$58.00/US$68.00/US$74.00	WTI	$	3.3
3-way option[3]	Jul 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$69.90/US$75.00	WTI	$	1.8
3-way option[3]	Jul 2019 to Dec 2019	1,000 bbl/d	US$61.00/US$71.00/US$76.00	WTI	$	1.9
3-way option[3]	Jul 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$78.00	WTI	$	2.1
3-way option[3]	Jul 2019 to Dec 2019	1,000 bbl/d	US$55.50/US$65.50/US$75.50	Brent	$	0.6
3-way option[3]	Jul 2019 to Dec 2019	1,000 bbl/d	US$60.00/US$70.00/US$77.55	Brent	$	1.1
3-way option[3]	Jul 2019 to Dec 2019	1,000 bbl/d	US$63.00/US$73.00/US$83.00	Brent	$	1.5
3-way option[3]	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$65.60	WTI	$	1.1
3-way option[3]	Jan 2020 to Dec 2020	1,500 bbl/d	US$51.00/US$59.00/US$66.00	WTI	$	1.1
3-way option[3]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$59.50/US$66.15	WTI	$	0.9
3-way option[3]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.00	WTI	$	1.0
3-way option[3]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$65.60	WTI	$	0.9
3-way option[3]	Jan 2020 to Dec 2020	1,000 bbl/d	US$51.00/US$60.00/US$66.05	WTI	$	1.0
3-way option[3]	Jan 2020 to Dec 2020	2,000 bbl/d	US$51.00/US$60.00/US$66.70	WTI	$	2.1
Swaption[4]	Jan 2020 to Dec 2020	1,000 bbl/d	US$62.50/bbl	WTI	$	(0.7)
Swaption[4]	Jan 2020 to Dec 2020	1,000 bbl/d	US$63.20/bbl	WTI	$	(0.6)
Natural Gas						
Fixed - Sell	Jul 2019 to Dec 2019	5,000 mmbtu/d	US$3.15	NYMEX	$	0.8
Fixed - Sell	Jul 2019 to Sep 2019	10,000 mmbtu/d	US$2.79	NYMEX	$	0.6
Fixed - Sell	Oct 2019 to Dec 2019	10,000 mmbtu/d	US$2.88	NYMEX	$	0.5
Total					**$**	**41.3**
Financial derivatives - Current asset						37.9
Financial derivatives - Non-current asset						3.4

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

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

	Three Months Ended June 30		Six Months Ended June 30	
	2019	2018	**2019**	2018
Realized financial derivatives (gain) loss	**$ (12,993)**	$ 29,408	**$ (31,807)**	$ 39,249
Unrealized financial derivatives (gain) loss	**(14,673)**	47,385	**38,588**	65,094
Financial derivatives (gain) loss	**$ (27,666)**	$ 76,793	**$ 6,781**	$ 104,343

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

Period	Volume
Jul 2019 to Oct 2019	1,000 bbl/d
Jul 2019 to Dec 2019	10,000 bbl/d
Jan 2020 to Dec 2020	7,500 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

Neil J. Roszell
Chairman of the Board

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

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

Trudy M. Curran (2)(4)
Director

Naveen Dargan (1)(3)
Director

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
Caisse Centrale Desjardins
Export Development Canada
National Bank of Canada
Royal Bank of Canada
The Toronto-Dominion Bank
Wells Fargo Bank

OFFICERS

Edward D. LaFehr
President and Chief Executive Officer

Rodney D. Gray
Executive Vice President and
Chief Financial Officer

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