BAYTEX
ENERGY CORP.

Q2 REPORT / 2018

PRESS RELEASE

CALGARY, ALBERTA (July 31, 2018) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three and six months ended June 30, 2018 (all amounts are in Canadian dollars unless otherwise noted).

"We continued to deliver on our operational and financial targets in the second quarter, which included strong drilling results in Canada and the Eagle Ford. In addition, we are excited to be moving forward with the proposed merger with Raging River as we unite two strong oil companies with exceptional people and assets. We believe the combined company will deliver a powerful combination of per share production growth and strong free cash flow. We will be well-positioned to optimize our capital investment across our high rate of return asset base," commented Ed LaFehr, President and Chief Executive Officer.

Highlights

- Entered into an arrangement agreement with Raging River Exploration Inc. ("Raging River") to create a well-capitalized, oil-weighted company with an attractive growth and free cash flow profile. This strategic combination is expected to close on August 22, 2018.
- Delivered production of 70,664 boe/d (79% oil and NGL) with exploration and development capital expenditures of $79 million during Q2/2018.
- Generated adjusted funds flow of $107 million ($0.45 per basic share) or $136 million excluding realized financial derivatives gains and losses.
- Realized an operating netback of $35.42/boe in the Eagle Ford, the strongest since Q3/2014. Our Eagle Ford light oil and condensate production received a premium sales price of US$67.62/bbl (or $87.38/bbl) given its proximity to Gulf Coast markets.
- Established average 30-day initial gross production rates of approximately 1,850 boe/d per well from 32 (7.6 net) wells in the Eagle Ford that commenced production in the second quarter. This represents an approximate 25% improvement over wells brought on production in 2017.
- Executed our Q2/2018 drilling program in Canada as planned with production increasing to 34,042 boe/d. Our first two northern Seal wells at Peace River generated 30-day initial production rates of 918 boe/d and 660 boe/d, respectively.
- Expanded our crude by rail volumes to 8,300 bbl/d (33% of our heavy oil production) in Q2/2018. We have secured additional rail capacity, which will see our crude oil volumes delivered to market by rail increase to approximately 9,500 bbl/d in Q3/2018 and 10,500 bbl/d in Q4/2018.

	Three Months Ended			Six Months Ended	
	June 30, 2018	March 31, 2018	June 30, 2017	**June 30, 2018**	June 30, 2017
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 347,605**	$ 286,067	$ 277,536	**$ 633,672**	$ 538,085
Adjusted funds flow (1)	**106,690**	84,255	83,136	**190,945**	164,505
Per share – basic	**0.45**	0.36	0.35	**0.81**	0.70
Per share – diluted	**0.45**	0.36	0.35	**0.81**	0.70
Net income (loss)	**(58,761)**	(62,722)	9,268	**(121,483)**	20,364
Per share – basic	**(0.25)**	(0.27)	0.04	**(0.51)**	0.09
Per share – diluted	**(0.25)**	(0.27)	0.04	**(0.51)**	0.09
Exploration and development	**78,830**	93,534	78,007	**172,364**	174,566
Acquisitions, net of divestitures	**(21)**	(2,026)	5,226	**(2,047)**	71,230
Total oil and natural gas capital expenditures	**$ 78,809**	$ 91,508	$ 83,233	**$ 170,317**	$ 245,796
Bank loan (2)	**$ 213,538**	$ 212,571	$ 264,032	**$ 213,538**	$ 264,032
Long-term notes (2)	**1,548,490**	1,525,595	1,541,694	**1,548,490**	1,541,694
Long-term debt	**1,762,028**	1,738,166	1,805,726	**1,762,028**	1,805,726
Working capital (surplus) deficiency	**22,807**	45,213	13,661	**22,807**	13,661
Net debt (3)	**$ 1,784,835**	$ 1,783,379	$ 1,819,387	**$ 1,784,835**	$ 1,819,387

	Three Months Ended			Six Months Ended	
	June 30, 2018	March 31, 2018	June 30, 2017	**June 30, 2018**	June 30, 2017
OPERATING					
Daily production					
Heavy oil (bbl/d)	**25,544**	24,868	25,577	**25,208**	25,104
Light oil and condensate (bbl/d)	**21,100**	20,967	22,370	**21,034**	21,996
NGL (bbl/d)	**9,419**	9,143	9,693	**9,281**	9,003
Total oil and NGL (bbl/d)	**56,063**	54,978	57,640	**55,523**	56,103
Natural gas (mcf/d)	**87,605**	87,261	91,028	**87,434**	89,771
Oil equivalent (boe/d @ 6:1) (4)	**70,664**	69,522	72,812	**70,095**	71,065
Benchmark prices					
WTI oil (US$/bbl)	**67.88**	62.87	48.28	**65.37**	50.10
WCS heavy oil (US$/bbl)	**48.61**	38.59	37.16	**43.60**	37.25
Edmonton par oil ($/bbl)	**80.58**	72.06	61.92	**76.32**	62.95
LLS oil (US$/bbl)	**71.37**	67.07	49.70	**69.24**	51.10
Baytex average prices (before hedging)					
Heavy oil ($/bbl) (5)	**49.70**	33.33	37.62	**41.67**	36.81
Light oil and condensate ($/bbl)	**86.75**	79.20	60.68	**83.01**	61.94
NGL ($/bbl)	**31.37**	26.17	22.70	**28.82**	24.38
Total oil and NGL ($/bbl)	**60.56**	49.63	44.06	**55.18**	44.67
Natural gas ($/mcf)	**2.56**	2.95	3.62	**2.75**	3.57
Oil equivalent ($/boe)	**51.22**	42.96	39.41	**47.15**	39.77
CAD/USD noon rate at period end	**1.3142**	1.2901	1.2983	**1.3142**	1.2983
CAD/USD average rate for period	**1.2911**	1.2651	1.3447	**1.2781**	1.3338
COMMON SHARE INFORMATION					
TSX					
Share price (Cdn$)					
High	**6.23**	4.35	4.81	**6.23**	6.97
Low	**3.34**	3.01	2.87	**3.01**	2.87
Close	**4.37**	3.53	3.15	**4.37**	3.15
Volume traded (thousands)	**391,396**	177,572	216,383	**568,968**	472,026
NYSE					
Share price (US$)					
High	**4.85**	3.54	3.63	**4.85**	5.20
Low	**2.59**	2.37	2.15	**2.37**	2.15
Close	**3.33**	2.74	2.43	**3.33**	2.43
Volume traded (thousands)	**175,808**	118,236	109,758	**294,044**	248,931
Common shares outstanding (thousands)	**236,662**	236,578	234,204	**236,662**	234,204

Notes:

(1) 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 of performance as it demonstrates our ability to generate the cash flow necessary to fund capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use the ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and 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. 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, 2018.

(2) Principal amount of instruments.

(3) Net debt is not a measurement based on GAAP in Canada, but is a financial term commonly used in the oil and gas industry. We define net debt to be the sum of monetary working capital (which is current assets less current liabilities (excluding current financial derivatives and onerous contracts)) and the principal amount of both the long-term notes and the bank loan.

(4) 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.

(5) We include the cost of blending diluent when calculating our realized heavy oil price.

Strategic Combination with Raging River

On June 18, 2018, Baytex and Raging River announced that their respective boards of directors had unanimously agreed to a strategic combination of the two companies (the “Transaction”). The combined company, which will operate under the Baytex name, will be a well-capitalized, oil-weighted company with an attractive growth and free cash flow profile provided by its world class assets across North America.

The combined company is expected to have production of approximately 94,000 boe/d from a diverse portfolio of high quality oil assets, including Viking, Peace River, Lloydminster and East Duvernay Shale properties in Canada and the Eagle Ford in Texas. The combined company will have a deep inventory of high quality drilling prospects that generate top tier returns on invested capital and have the capability to deliver meaningful organic production growth.

The Transaction will result in holders of common shares of Raging River receiving, directly or indirectly, 1.36 common shares of Baytex for each Raging River Share owned. The Transaction is subject to approval by the shareholders of both companies, the Court of Queen’s Bench of Alberta and certain regulatory and other authorities, and is subject to the satisfaction or waiver of other customary closing conditions.

The joint management information circular was mailed to shareholders of each of Baytex and Raging River on July 20, 2018. Baytex and Raging River shareholders will hold their respective shareholder meetings on August 21, 2018 and the Transaction is expected to close on August 22, 2018. For further information on the Transaction, please see the joint management information circular dated July 12, 2018 and the joint press release dated June 18, 2018.

Operating Results

Our operating results for the second quarter were consistent with our expectations as we continued to deliver on our operational and financial targets. We successfully executed our drilling program with strong results realized in the Eagle Ford and Canada.

Production increased 2% to average 70,664 boe/d (79% oil and NGL) in Q2/2018, as compared to 69,522 boe/d (79% oil and NGL) in Q1/2018. Production in the first half of 2018 averaged 70,095 boe/d. During the second quarter, exploration and development capital expenditures totaled $79 million, bringing the aggregate spending in the first half of 2018 to $172 million. We participated in the drilling of 36 (8.1 net) wells with a 100% success rate during the second quarter.

Our 2018 production guidance range is unchanged at 68,000 to 72,000 boe/d with budgeted exploration and development capital expenditures of $325 to $375 million, and does not include the integration of Raging River, which is expected to close on August 22, 2018. Following closing of the Transaction, Baytex will provide revised guidance for full-year 2018.

Eagle Ford

Our Eagle Ford asset in South Texas is one of the premier oil resource plays in North America. The asset generates the highest cash netbacks in our portfolio and contains a significant inventory of development prospects. In Q2/2018, we allocated 61% of our exploration and development expenditures to this asset and production averaged 36,622 boe/d (78% oil and NGL) during the second quarter, as compared to 36,017 boe/d in Q1/2018.

We continue to see strong well performance driven by enhanced completions in Karnes County. In addition, early results from Atascosa County are encouraging as we exploit the oil window on the western portion of our lands. In Q2/2018, we participated in the drilling of 18 (2.6 net) wells, commenced production from 32 (7.6 net) wells and at June 30, 2018 had 70 (18.5 net) wells waiting on completion. The wells that have been on production for more than 30 days established 30-day initial production rates of approximately 1,850 boe/d (65% light oil and condensate), which represents an approximate 25% improvement over wells brought on production in 2017. These wells were completed with approximately 28 effective frac stages per well (compared to 23 in 2015) and proppant per completed foot of approximately 2,100 pounds (compared to 1,100 pounds in 2015).

Peace River

Our Peace River region, located in northwest Alberta, has been a core asset since we commenced operations in the area in 2004. Through our innovative multi-lateral horizontal drilling and production techniques, we are able to generate some of the strongest capital efficiencies in the oil and gas industry.

Production averaged 16,800 boe/d (92% heavy oil) during the second quarter, as compared to 16,500 boe/d in Q1/2018. In Q2/2018, we drilled one (1.0 net) well and commenced production from four (4.0 net) wells. Our first two northern Seal wells at Peace River generated 30-day initial production rates of 918 boe/d and 660 boe/d, respectively. Approximately 10 wells are anticipated to be drilled in the northern Seal area in 2018. We expect to have a second rig starting up in August as we continue to build operational momentum heading into 2019.

Lloydminster

Our Lloydminster region is characterized by multiple stacked pay formations at relatively shallow depths. The area has been successfully developed through vertical and horizontal drilling, water flood, steam-assisted gravity drainage operations and, more recently, the implementation of polymer flooding to further enhance reserves recovery. We have also adopted, where applicable, the multi-lateral well design and geosteering capability that we have successfully utilized at Peace River.

Production averaged 10,300 boe/d (99% heavy oil) during the second quarter as compared to 10,000 boe/d in Q1/2018. We drilled 12 (3.3 net) crude oil wells in Q2/2018. During the second quarter, seven (7.0 net) wells drilled in Q1/2018 established peak 30-day initial production rates of approximately 200 bbl/d per well. In addition, we continued to advance our Kerrobert thermal project. Production at Kerrobert averaged 600 boe/d in H1/2018 and we expect to exit 2018 producing approximately 2,000 boe/d. We recommenced our Soda Lake multi-lateral drilling program in June and expect to have two rigs running in the second half of the year.

Financial Review

We generated adjusted funds flow of $107 million ($0.45 per basic share) in Q2/2018, compared to $84 million ($0.36 per basic share) in Q1/2018 and $83 million ($0.35 per basic share) in Q2/2017. The increase in adjusted funds flow is largely attributable to stronger oil price realizations, partially offset by realized financial derivatives losses.

Excluding realized financial derivatives gains and losses, adjusted funds flow in Q2/2018 was $136 million, compared to $94 million in Q1/2018. This represents the highest quarterly adjusted funds flow (excluding realized financial derivatives gains and losses) since Q4/2014 and demonstrates the strength of our diversified asset portfolio.

Financial Liquidity

We maintain strong financial liquidity with our US$575 million revolving credit facilities approximately 70% undrawn and our first long-term note maturity not until 2021. With our strategy to target exploration and development capital expenditures at a level that approximates our adjusted funds flow, we expect this liquidity position to be stable going forward. In the first six months of 2018, exploration and development capital expenditures totaled $172 million, as compared to adjusted funds flow of $191 million ($230 million excluding realized financial derivatives losses).

On April 25, 2018, we extended the maturity of our revolving credit facilities by one year to June 2020. These facilities are covenant-based and do not require annual or semi-annual reviews. We are well within the financial covenants on these facilities as our Senior Secured Debt to Bank EBITDA ratio as at June 30, 2018 was 0.6:1.0, compared to a maximum permitted ratio of 3.5:1.0, and our interest coverage ratio was 4.1:1.0, compared to a minimum required ratio of 2.0:1.0.

Our net debt totaled $1.78 billion at June 30, 2018, which is down from $1.82 billion at June 30, 2017.

Operating Netback

Our operating netback (excluding realized financial derivatives gains and losses) improved 48% to $27.08/boe in Q2/2018, as compared to $18.30/boe in Q2/2017. During the second quarter, we benefited from continued strong liquids pricing in the Eagle Ford and improved heavy oil price realizations in Canada. The Eagle Ford generated an operating netback of $35.42/boe during Q2/2018 while our Canadian operations generated an operating netback of $18.12/boe.

In Q2/2018, the price for West Texas Intermediate light oil (“WTI”) averaged US$67.88/bbl, as compared to US$48.28/bbl in Q2/2017. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select (“WCS”) and WTI, averaged US$19.27/bbl in Q2/2018, as compared to US$11.12/bbl in Q2/2017.

In the Eagle Ford, our assets are proximal to Gulf Coast markets with light oil and condensate production priced off the Louisiana Light Sweet (“LLS”) crude oil benchmark, which is a function of the Brent price. In Q2/2018, the price for LLS averaged US$71.37/bbl, as compared to US$49.70/bbl in Q2/2017. During the second quarter, our light oil and condensate realized price in the Eagle Ford of US$67.62/bbl (or $87.38/bbl) represented a US$3.75/bbl discount to LLS.

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

	Three Months Ended June 30					
	2018			2017		
($ per boe except for sales volume)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Sales volume (boe/d)	**34,042**	**36,622**	**70,664**	34,284	38,528	72,812
Total sales, net of blending and other expense	**$ 41.61**	**$ 60.16**	**$ 51.22**	$ 33.86	$ 44.34	$ 39.41
Less:						
Royalties	**5.81**	**17.77**	**12.01**	4.53	13.09	9.06
Operating expense	**15.15**	**6.97**	**10.91**	14.74	7.11	10.70
Transportation expense	**2.53**	**—**	**1.22**	2.88	—	1.35
Operating netback	**$ 18.12**	**$ 35.42**	**$ 27.08**	$ 11.71	$ 24.14	$ 18.30
Realized financial derivatives (loss) gain	**—**	**—**	**(4.57)**	—	—	0.40
Operating netback after financial derivatives (loss) gain	**$ 18.12**	**$ 35.42**	**$ 22.51**	$ 11.71	$ 24.14	$ 18.70

Risk Management

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. We realized a financial derivatives loss of $29 million in Q2/2018 due to the increased price of crude oil relative to the prices set in our contracts. A complete listing of our financial derivative contracts can be found in Note 17 to our Q2/2018 financial statements.

As part of our risk management program, we also transport crude oil to markets by rail when economics warrant. In Q2/2018, we delivered 8,300 bbl/d (approximately 33%) of our heavy oil volumes to market by rail, up from 6,500 bbl/d in Q1/2018. We have secured additional rail capacity, which will see our crude oil volumes delivered to market by rail increase to approximately 9,500 bbl/d in Q3/2018 and 10,500 bbl/d in Q4/2018. We have also successfully commenced the re-contracting of future year crude by rail commitments, which to-date total 7,500 bbl/d for 2019 and 5,000 bbl/d for 2020.

2018 Guidance

The following table summarizes our 2018 annual guidance and compares it to our 2018 year-to-date actual results. Following closing of the strategic combination with Raging River, we will provide revised guidance for the combined company.

	Guidance [1]	H1/2018	Variance
Exploration and development capital ($ millions)	325 - 375	172.4	-%
Production (boe/d)	68,000 - 72,000	70,095	-%
Expenses:			
Royalty rate (%)	~ 23.0	23.7	1%
Operating ($/boe)	10.50 - 11.25	10.72	-%
Transportation ($/boe)	1.35 - 1.45	1.29	(4)%
General and administrative ($ millions)	~ 44 (1.72/boe)	21.6 (1.70/boe)	(1)%
Interest ($ millions)	~ 100 (3.95/boe)	50.0 (3.94/boe)	-%

Note:

(1) As announced on December 7, 2017.

Advisory Regarding Forward-Looking Statements

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

Specifically, this press release contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that the combined enterprise of Baytex and Raging River will deliver per share production growth and strong free cash flow and be able to optimize capital investment; the expected closing date of the strategic combination with Raging River; the amount of crude oil we expect to deliver to market by rail in Q3/2018 and Q4/2018; the anticipated attributes of Baytex and Raging River as a combined company, including its daily production rate; Baytex's standalone 2018 production and capital expenditure guidance; that revised guidance will be provided on closing of the Raging River merger; our Eagle Ford assets, including our assessment that: it is a premier oil resource play, generates our highest cash netbacks and has a significant development inventory; our assessment that we can generate some of the strongest capital efficiencies in the oil and gas industry at our Peace River assets; our drilling plans in Peace River for the balance of 2018; the expected 2018 exit production rate for our Kerrobert thermal project; our drilling plans in Soda Lake for the balance of 2018; our strategy to target capital expenditures at a level that approximates our adjusted funds flow; our belief that we have strong financial liquidity and that our liquidity position will remain stable going forward; 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; and Baytex's standalone expected royalty rate and operating, transportation, general and administration and interest expenses for 2018. 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 and contingent resources 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; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; availability and cost of gathering, processing and pipeline systems; public perception and its influence on the regulatory regime; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; 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; 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; 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, 2017, 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.

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 of performance as it demonstrates our ability to generate the cash flow necessary to fund capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use the ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and 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. 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, 2018.

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 capital required to offset production declines on an annual basis and maintain flat production volumes.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of monetary working capital (which is current assets less current liabilities (excluding current financial derivatives and onerous contracts)) 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.

Bank EBITDA is not a measurement based on GAAP in Canada. We define Bank EBITDA as our consolidated net income attributable to shareholders before interest, taxes, depletion and depreciation, and certain other non-cash items as set out in the credit agreement governing our revolving credit facilities. Bank EBITDA is used to measure compliance with certain financial covenants.

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.

Advisory Regarding Oil and Gas Information

Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. 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.

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.

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, 2018. This information is provided as of July 30, 2018. 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, 2018 ("Q2/2018" and "YTD 2018") have been compared with the results for the three and six months ended June 30, 2017 ("Q2/2017" and "YTD 2017"). This MD&A should be read in conjunction with the Company's condensed consolidated interim unaudited financial statements ("consolidated financial statements") for the three and six months ended June 30, 2018, its audited comparative consolidated financial statements for the years ended December 31, 2017 and 2016, together with the accompanying notes, and its Annual Information Form for the year ended December 31, 2017. 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, and all tabular amounts are in thousands of Canadian dollars, except for percentages, per common share amounts or as otherwise noted.

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"). We refer you to the end of the MD&A for our advisory on forward-looking information and statements and a summary of our non-GAAP measures.

SECOND QUARTER HIGHLIGHTS

Business combination

On June 18, 2018, Baytex and Raging River Exploration Inc. ("Raging River") announced that their respective boards of directors unanimously agreed to a strategic combination of the two companies (the "Transaction"). The combined entity will be well-capitalized and oil-weighted with core assets across North America. The companies entered into an agreement (the "Arrangement Agreement") to effect the Transaction by way of a plan of arrangement under the *Business Corporations Act* (Alberta). Under the Transaction, Baytex will issue 1.36 common shares for each common share of Raging River.

The business combination is subject to approval by the shareholders of both companies, the Court of Queen's Bench of Alberta and certain regulatory and other authorities, and is subject to the satisfaction or waiver of other customary closing conditions. A joint information circular containing information relevant to the Arrangement was filed on July 20, 2018. Each company will hold a special meeting of shareholders on August 21, 2018. The shareholders of Raging River will be asked to approve the Arrangement. The shareholders of Baytex will be asked to approve the issuance of common shares of Baytex pursuant to the Arrangement. The business combination is anticipated to close on August 22, 2018. Baytex will update its 2018 guidance upon completion of the arrangement.

Second quarter operating and financial results

Baytex generated operating and financial results during Q2/2018 that were in line with our annual guidance. We generated adjusted funds flow of $106.7 million while investing $78.8 million on exploration and development activities. Strong well performance in the U.S. and Canada resulted in average production of 70,664 boe/d which approximates the mid-point of our annual guidance range of 68,000 - 72,000 boe/d.

Production of 70,664 boe/d for Q2/2018 was slightly higher than Q1/2018 production of 69,522 boe/d and was slightly lower than 72,812 boe/d reported for Q2/2017. In the U.S., strong performance from wells that commenced production during Q2/2018 resulted in average daily production of 36,622 boe/d that was slightly higher than 36,017 boe/d for Q1/2018 while lower completion activity during YTD 2018 resulted in lower average daily production for Q2/2018 relative to 38,528 boe/d in Q2/2017. In Canada, our capital programs at Lloydminster and Peace River continue to deliver strong production results and contributed to slightly higher daily production for our Canadian operations in Q2/2018 as compared to Q1/2018.

Our capital program in Canada was focused on our Peace River and Lloydminster properties with a total of $30.6 million invested on exploration and development activities during Q2/2018. At Peace River, we drilled one (1.0 net) well and commenced production from four (4.0 net) wells during Q2/2018. Our first multi-lateral horizontal well on our northern Seal acreage (acquired in January 2017) commenced production during Q2/2018 and established a 30-day initial production rate of approximately 918 boe/d. The second multi-lateral horizontal well on our northern Seal acreage was brought online at the end of June and recently established a 30-day initial production rate of approximately 660 boe/d. Drilling operations at Lloydminster included 12 (3.3 net) wells during Q2/2018. Strong well performance resulted in average production of 34,042 boe/d during Q2/2018 which is slightly higher than 33,505 boe/d for Q1/2018 and consistent with 34,284 boe/d for Q2/2017.

In the U.S., we invested $48.2 million on exploration and development activity during Q2/2018 and drilled 18 (2.6 net) wells and commenced production from 32 (7.6 net) wells. As expected, drilling and completion activity was lower in Q2/2018 relative to Q2/2017. We continue to see strong well performance from enhanced completions techniques utilizing higher proppant loading and increased frac stages. Wells that commenced production during Q2/2018 have established 30-day initial gross production rates of approximately 1,850 boe/d per well. U.S. production was 36,622 boe/d for Q2/2018 which is slightly higher than 36,017 boe/d during Q1/2018 and down from 38,528 boe/d for Q2/2017 due to the lower completion activity during YTD 2018.

During Q2/2018, strong global oil demand along with ongoing compliance with production curtailments by the Organization of Petroleum Exporting Countries ("OPEC") resulted in further reductions in global crude oil inventories. The West Texas Intermediate ("WTI") benchmark oil price averaged US$67.88/bbl for Q2/2018 which is an increase of 41% from US$48.28/bbl for Q2/2017 and an increase of 8% from US$62.87/bbl for Q1/2018. The improvement in WTI market prices was partially offset by wider heavy oil differentials in Canada and resulted in an increase in our realized sales price to $51.22/boe in Q2/2018 from $39.41/boe in Q2/2017. Pipeline outages in late 2017 compounded existing transportation bottlenecks for heavy grades of Canadian crude oil and resulted in a widening of the price differential for Canadian heavy oil relative to WTI from US$11.12/bbl in Q2/2017 to US$19.27/bbl in Q2/2018.

We generated adjusted funds flow of $106.7 million for Q2/2018, an increase of $23.6 million from adjusted funds flow of $83.1 million reported for Q2/2017 and an increase of $22.4 million from $84.3 million reported for Q1/2018. The increase in adjusted funds flow in Q2/2018 was primarily due to higher realized prices relative to Q2/2017 and Q1/2018. Higher realized prices resulted in a $68.3 million increase in total sales, net of blending and other expense, relative to Q2/2017 and a $60.6 million increase in total sales, net of blending and other expense, relative to Q1/2018. The increase in realized prices for Q2/2018 was partially offset by higher royalties which were $17.2 million higher than Q2/2017 and $12.4 million higher than Q1/2018. We recorded hedging losses of $29.4 million million in Q2/2018 as compared to a gains of $2.6 million for Q2/2017 and losses of $9.8 million for Q1/2018.

At June 30, 2018, net debt was $1,784.8 million, an increase of $50.5 million from $1,734.3 million at December 31, 2017. The weakening of the Canadian dollar relative to the U.S. dollar increased the reported amount of our U.S. dollar denominated long-term notes at June 30, 2018 by $59.3 million.

RESULTS OF OPERATIONS

The Canadian operating segment includes 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					
	2018			2017		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**25,544**	**—**	**25,544**	25,577	—	25,577
Light oil and condensate	**842**	**20,258**	**21,100**	1,258	21,112	22,370
Natural Gas Liquids ("NGL")	**1,214**	**8,205**	**9,419**	964	8,729	9,693
Total liquids (bbl/d)	**27,600**	**28,463**	**56,063**	27,799	29,841	57,640
Natural gas (mcf/d)	**38,650**	**48,955**	**87,605**	38,908	52,120	91,028
Total production (boe/d)	**34,042**	**36,622**	**70,664**	34,284	38,528	72,812
Production Mix						
Heavy oil	**75%**	**—%**	**36%**	75%	—%	35%
Light oil and condensate	**2%**	**56%**	**30%**	4%	55%	31%
NGL	**4%**	**22%**	**13%**	3%	23%	13%
Natural gas	**19%**	**22%**	**21%**	18%	22%	21%

	Six Months Ended June 30					
	2018			2017		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**25,208**	**—**	**25,208**	25,104	—	25,104
Light oil and condensate	**850**	**20,184**	**21,034**	1,255	20,741	21,996
Natural Gas Liquids	**1,256**	**8,025**	**9,281**	1,031	7,972	9,003
Total liquids (bbl/d)	**27,314**	**28,209**	**55,523**	27,390	28,713	56,103
Natural gas (mcf/d)	**38,761**	**48,673**	**87,434**	38,181	51,590	89,771
Total production (boe/d)	**33,774**	**36,321**	**70,095**	33,754	37,311	71,065
Production Mix						
Heavy oil	**75%**	**—%**	**36%**	74%	—%	35%
Light oil and condensate	**3%**	**56%**	**30%**	4%	56%	31%
NGL	**4%**	**22%**	**13%**	3%	21%	13%
Natural gas	**18%**	**22%**	**21%**	19%	23%	21%

Average production for Q2/2018 was 70,664 boe/d which is slightly lower than 72,812 boe/d reported for Q2/2017 and approximates the mid-point of our 2018 annual guidance range of 68,000 - 72,000 boe/d. Completion activity on our U.S. properties was lower in YTD 2018 relative to YTD 2017 which resulted in lower average daily production for Q2/2018 compared to 72,812 boe/d reported for Q2/2017. Strong well performance in Canada and the U.S. resulted in production for Q2/2018 that was up from 69,522 boe/d reported for Q1/2018.

Production in Canada averaged 34,042 boe/d for Q2/2018 which is consistent with average production of 34,284 boe/d reported for Q2/2017 and an increase of 2% from 33,505 boe/d reported for Q1/2018. Strong production results from operated wells brought online at Peace River during Q2/2018 contributed to the increase in average daily production from Q1/2018 and resulted in average daily production for Q2/2018 that is consistent with Q2/2017.

In the U.S., production averaged 36,622 boe/d in Q2/2018 which is 5% lower than 38,528 boe/d reported for Q2/2017 and up 2% from 36,017 boe/d for Q1/2018. Strong well performance from 32 (7.6 net) wells that commenced production during Q2/2018 contributed to the increase in average daily production relative to Q1/2018. We commenced production from 59 (13.1 net) wells during YTD 2018 as compared to 68 (17.5 net) wells brought on production in YTD 2017, which resulted in lower average daily production for Q2/2018 relative to the same period of 2017.

Our average daily production of 70,095 boe/d for YTD 2018 was slightly lower than 71,065 boe/d reported for YTD 2017 and approximates the mid-point of our annual guidance range of 68,000 - 72,000 boe/d for 2018. Strong well performance at Lloydminster and Peace River during YTD 2018 offset the impact of natural declines along with the impact of minor property dispositions and resulted in average daily production of 33,774 boe/d for Canada which is consistent with YTD 2017. Lower completion activity in the U.S. during YTD 2018 resulted in average daily production of 36,321 boe/d which is slightly lower than 37,311 boe/d reported for YTD 2017.

Commodity Prices

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

Crude Oil

Global benchmark prices for crude oil have continued to strengthen in 2018 as robust global demand and sustained compliance with OPEC production curtailments continue to reduce global inventory levels. We compare our liquids pricing to the WTI benchmark oil price which is the representative index for inland North American light oil at Cushing, Oklahoma. The WTI benchmark price averaged US$67.88/bbl during Q2/2018, which is an increase of 41% compared to an average of US$48.28/bbl during Q2/2017 and an increase of 8% compared to an average of US$62.87/bbl during Q1/2018. During YTD 2018, the WTI benchmark price averaged US$65.37/bbl representing a 30% increase relative to an average of US$50.10/bbl during the same period of 2017.

Our U.S. crude oil production is primarily priced off the Louisiana Light Sweet ("LLS") stream at St. James, Louisiana, which is the representative benchmark for light oil pricing at the U.S. Gulf coast. The LLS benchmark price remained strong during Q2/2018 averaging US$71.37/bbl which is 44% higher than US$49.70/bbl during Q2/2017 and 6% higher than US$67.07/bbl during Q1/2018. The LLS benchmark price continued to improve relative to WTI during YTD 2018 as a result of higher global crude oil pricing. During YTD 2018, LLS averaged US$69.24/bbl, which is a premium of US$3.87/bbl relative to WTI, compared to US$51.10/bbl or a US$1.00/bbl premium to WTI for the same period of 2017.

The price received for our heavy oil production in Canada is based on the Western Canadian Select ("WCS") benchmark price which trades at a discount to WTI due to the quality and lack of egress for the heavier Canadian grades of crude oil. Pipeline outages in late 2017 and increased heavy oil production have compounded existing transportation constraints and have resulted in increased crude inventories in Western Canada and a widening of the WCS heavy oil differential during YTD 2018. The WCS heavy oil differential averaged US$19.27/bbl in Q2/2018 and US$21.77/bbl in YTD 2018 as compared to US$11.12/bbl and US$12.85/bbl for the same periods of 2017, respectively.

Natural Gas

North American natural gas prices were lower during YTD 2018 relative to YTD 2017 as natural gas supply growth has outpaced growth in demand. Canadian natural gas prices remained challenged during YTD 2018 as lack of egress in Western Canada have impacted natural gas prices in the region. Increasing supply from U.S. shale production has resulted in a decline in U.S. natural gas benchmark prices during YTD 2018 as compared to YTD 2017.

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. During Q2/2018, the NYMEX natural gas benchmark averaged US$2.80/mmbtu, a decrease of 12% from US$3.18/mmbtu for the same period of 2017. The NYMEX natural gas benchmark averaged US$2.90/mmbtu during YTD 2018 which is 11% lower than US$3.25/mmbtu for YTD 2017.

In Canada, we receive natural gas pricing based on the AECO benchmark which averaged $1.03/mcf during Q2/2018 which is 63% lower than $2.77/mcf during Q2/2017. The AECO benchmark 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 $1.44/mcf during YTD 2018 which is a decrease of 50% as compared to an average of $2.86/mcf during YTD 2017.

The following tables compare selected benchmark prices and our average realized selling prices for the three and six months ended June 30, 2018 and 2017.

	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	Change	**2018**	2017	Change
Benchmark Averages						
WTI oil (US$/bbl)[1]	**67.88**	48.28	41 %	**65.37**	50.10	30 %
WTI oil (CAD$/bbl)	**87.64**	64.93	35 %	**83.56**	66.82	25 %
WCS heavy oil differential (US$/bbl)	**(19.27)**	(11.12)	73 %	**(21.77)**	(12.85)	69 %
WCS heavy oil differential (CAD$/bbl)	**(24.89)**	(14.96)	66 %	**(27.83)**	(17.14)	62 %
WCS heavy oil (US$/bbl)[2]	**48.61**	37.16	31 %	**43.60**	37.25	17 %
WCS heavy oil (CAD$/bbl)	**62.75**	49.97	26 %	**55.73**	49.68	12 %
LLS oil (US$/bbl)[3]	**71.37**	49.70	44 %	**69.24**	51.10	35 %
LLS oil (CAD$/bbl)	**92.14**	66.83	38 %	**88.49**	68.15	30 %
CAD/USD average exchange rate	**1.2911**	1.3447	(4)%	**1.2781**	1.3338	(4)%
Edmonton par oil ($/bbl)	**80.58**	61.92	30 %	**76.32**	62.95	21 %
AECO natural gas price ($/mcf)[4]	**1.03**	2.77	(63)%	**1.44**	2.86	(50)%
NYMEX natural gas price (US$/mmbtu)[5]	**2.80**	3.18	(12)%	**2.90**	3.25	(11)%

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) WCS refers to the average posting price for the benchmark WCS heavy oil.
(3) LLS refers to the Argus trade month average for Louisiana Light Sweet 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					
	2018			2017		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices[1]						
Heavy oil ($/bbl)[2]	**$ 49.70**	**$ —**	**$ 49.70**	$ 37.62	$ —	$ 37.62
Light oil and condensate ($/bbl)	**71.61**	**87.38**	**86.75**	54.07	61.07	60.68
NGL ($/bbl)	**37.05**	**30.53**	**31.37**	28.17	22.10	22.70
Natural gas ($/mcf)	**1.07**	**3.73**	**2.56**	2.66	4.34	3.62
Weighted average ($/boe)[2]	**$ 41.61**	**$ 60.16**	**$ 51.22**	$ 33.86	$ 44.34	$ 39.41

	Six Months Ended June 30					
	2018			2017		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices[1]						
Heavy oil ($/bbl)[2]	**$ 41.67**	**$ —**	**$ 41.67**	$ 36.81	$ —	$ 36.81
Light oil and condensate ($/bbl)	**67.18**	**83.68**	**83.01**	56.04	62.30	61.94
NGL ($/bbl)	**32.76**	**28.21**	**28.82**	29.17	23.76	24.38
Natural gas ($/mcf)	**1.50**	**3.75**	**2.75**	2.65	4.25	3.57
Weighted average ($/boe)[2]	**$ 35.73**	**$ 57.76**	**$ 47.15**	$ 33.35	$ 45.59	$ 39.77

(1) Baytex's risk management strategy employs both oil and natural gas financial and physical forward contracts (fixed price forward sales and collars) and heavy oil differential physical delivery contracts (fixed price and percentage of WTI). The pricing information in this table excludes the impact of financial derivatives.
(2) Realized heavy oil prices are calculated based on sales volumes and sales dollars, net of blending and other expense.

Average Realized Sales Prices

Our weighted average sales price was $47.15/boe for YTD 2018, up $7.38/boe from $39.77/boe for the first six months of 2017. The increase is primarily a result of higher crude oil pricing in 2018 relative to 2017 which helped to increase the weighted average sales price for our production in the U.S. and Canada.

In Canada, our realized heavy oil sales price, net of blending and other expense, averaged $49.70/bbl for Q2/2018 which is $12.08/bbl higher than realized pricing of $37.62/bbl for Q2/2017. Our Canadian heavy oil production requires blending with diluent in order to meet pipeline transportation specifications. The price received for the blended product is recorded as heavy oil sales revenue. We include the cost of blending diluent in our realized heavy oil sales price in order to compare our realized pricing on our produced volumes to the WCS benchmark. The increase in our realized heavy oil sale price, net of blending and other expense, reflects the $12.78/bbl increase in the WCS benchmark in Q2/2018 relative to the same period of 2017. Our realized heavy oil sales price, net of blending and other expense, increased $4.86/bbl from $36.81/bbl for YTD 2017 to $41.67/bbl for YTD 2018 which is relatively consistent with the $6.05/bbl increase in the WCS benchmark price over the same period.

Our realized Canadian light oil and condensate price of $71.61/bbl for Q2/2018 and $67.18/bbl for YTD 2018 increased from $54.07/bbl for Q2/2017 and $56.04/bbl for YTD 2017 due to the increase in market prices for crude oil over the same periods. During Q3/2017, we disposed of certain oil and natural gas properties in our Conventional business unit which produced a higher quality light oil than our remaining Canadian properties. As a result, the increase in our realized light oil and condensate price for Q2/2018 and YTD 2018 was slightly lower than the increase in Edmonton par pricing relative to the same periods of 2017.

In the U.S., our realized light oil and condensate price was $87.38/bbl for Q2/2018 and $83.68/bbl for YTD 2018 compared to $61.07/bbl for Q2/2017 and $62.30/bbl for YTD 2017. Our realized light oil and condensate pricing realizations improved in Q3/2017 following the re-negotiation of certain marketing arrangements along with increased pipeline capacity which has reduced the pricing differential on our U.S. light oil and condensate realized price relative to the LLS benchmark. As a result, the increase in our realized light oil and condensate pricing for Q2/2018 and YTD 2018 was slightly higher than the increase in the LLS benchmark price (expressed in Canadian dollars) of $25.31/bbl and $20.34/bbl relative to the same periods of 2017, respectively.

For Q2/2018, our realized NGL price was $31.37/bbl or 36% of WTI (expressed in Canadian dollars) compared to $22.70/bbl or 35% of WTI in Q2/2017. Our realized NGL price for YTD 2018 was $28.82/bbl or 34% of WTI (expressed in Canadian dollars) relative to $24.38/bbl or 36% of WTI for YTD 2017. Our realized 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. The decrease in our realized price relative to WTI in YTD 2018 is consistent with market prices for the component products of NGL which were lower relative to WTI in 2018 as compared to 2017.

Our realized natural gas price in Canada was $1.07/mcf for Q2/2018 and $1.50/mcf for YTD 2018 compared to realized pricing of $2.66/mcf in Q2/2017 and $2.65/mcf in YTD 2017. The decrease is primarily due to lower AECO benchmark pricing in Q2/2018 and YTD 2018 relative to the comparative periods. A portion of our Canadian natural gas sales are referenced to the AECO daily index which was higher throughout YTD 2018 relative to the AECO monthly average index. Accordingly, our realized sales price for Q2/2018 decreased by $1.59/mcf from Q2/2017 relative to a $1.74/mcf decrease in the AECO monthly average over the same periods. Our realized natural gas price for YTD 2018 was $1.15/mcf lower compared to a $1.42/mcf decrease in AECO benchmark pricing over the same periods.

Our U.S. realized natural gas price was $3.73/mcf in Q2/2018 and $3.75/mcf for YTD 2018 compared to $4.34/mcf for Q2/2017 and $4.25/mcf for YTD 2017. The NYMEX natural gas benchmark (expressed in Canadian dollars) was lower in Q2/2018 and YTD 2018 and resulted in lower realized natural gas pricing for our U.S. properties relative to the same periods of 2017.

Petroleum and Natural Gas Sales

	Three Months Ended June 30					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Heavy oil	**$ 133,768**	**$ —**	**$ 133,768**	$ 103,996	$ —	$ 103,996
Light oil and condensate	**5,484**	**161,078**	**166,562**	6,189	117,335	123,524
NGL	**4,092**	**22,794**	**26,886**	2,472	17,555	20,027
Total liquids sales	**143,344**	**183,872**	**327,216**	112,657	134,890	247,547
Natural gas sales	**3,778**	**16,611**	**20,389**	9,406	20,583	29,989
Total petroleum and natural gas sales	**147,122**	**200,483**	**347,605**	122,063	155,473	277,536
Blending and other expense	**(18,239)**	**—**	**(18,239)**	(16,427)	—	(16,427)
Total sales, net of blending and other expense	**$ 128,883**	**$ 200,483**	**$ 329,366**	$ 105,636	$ 155,473	$ 261,109

	Six Months Ended June 30					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Heavy oil	**$ 225,651**	**$ —**	**$ 225,651**	$ 193,747	$ —	$ 193,747
Light oil and condensate	**10,336**	**305,684**	**316,020**	12,726	233,869	246,595
NGL	**7,448**	**40,972**	**48,420**	5,444	34,279	39,723
Total liquids sales	**243,435**	**346,656**	**590,091**	211,917	268,148	480,065
Natural gas sales	**10,502**	**33,079**	**43,581**	18,297	39,723	58,020
Total petroleum and natural gas sales	**253,937**	**379,735**	**633,672**	230,214	307,871	538,085
Blending and other expense	**(35,529)**	**—**	**(35,529)**	(26,484)	—	(26,484)
Total sales, net of blending and other expense	**$ 218,408**	**$ 379,735**	**$ 598,143**	$ 203,730	$ 307,871	$ 511,601

Total sales, net of blending and other expense, was $329.4 million for Q2/2018 which is an increase of $68.3 million or 26% from $261.1 million reported for Q2/2017. Total sales, net of blending and other expense, for Q2/2018 increased due to higher commodity prices which increased our weighted average realized sales price by 30% and a $78.3 million increase in total sales, net of blending and other expense relative to Q2/2017. This was offset by lower average daily production which was 3% lower compared to Q2/2017 which reduced total sales, net of blending and other expense, by $10.0 million in Q2/2018.

In Canada, total sales, net of blending and other expense, were $128.9 million for Q2/2018, up $23.2 million or 22% from $105.6 million in the same period of 2017. Total sales, net of blending and other expense, increased as a result of higher benchmark prices which increased our weighted average realized price and was partially offset by a $1.8 million increase in blending and other expense over Q2/2017. The benefit of a higher weighted average benchmark price was partially offset by lower average daily production for Q2/2018 which was slightly lower compared to the same period of 2017.

Petroleum and natural gas sales of $200.5 million during Q2/2018 in the U.S. increased 29% or $45.0 million from $155.5 million reported for Q2/2017. The increase was driven by higher benchmark pricing which resulted in a 36% increase in our weighted average realized price for Q2/2018 as compared to Q2/2017. The impact of higher weighted average realized pricing was partially offset by lower average daily production in the U.S. which was 5% lower than the comparative period of 2017.

Total sales, net of blending and other expense, of $598.1 million for YTD 2018 were $86.5 million or 17% higher than $511.6 million reported for the first six months of 2017. Benchmark prices for crude oil have been higher during YTD 2018 which resulted in a 19% increase in our weighted averaged realized price and a $94.8 million increase in total sales, net of blending and other expense, relative to YTD 2017. Average daily production of 70,095 boe/d for YTD 2018 was slightly lower than 71,065 boe/d for YTD 2017, which partially offset the impact of higher realized prices in 2018 and reduced total sales, net of blending and other expense by $8.3 million.

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the three and six months ended June 30, 2018 and 2017.

	Three Months Ended June 30					
	2018			2017		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 17,998**	**$ 59,207**	**$ 77,205**	$ 14,119	$ 45,895	$ 60,014
Average royalty rate[(1)]	**14.0%**	**29.5%**	**23.4%**	13.4%	29.5%	23.0%
Royalty rate per boe	**$ 5.81**	**$ 17.77**	**$ 12.01**	$ 4.53	$ 13.09	$ 9.06

	Six Months Ended June 30					
	2018			2017		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 29,332**	**$ 112,712**	**$ 142,044**	$ 26,752	$ 90,439	$ 117,191
Average royalty rate[1]	**13.4%**	**29.7%**	**23.7%**	13.1%	29.4%	22.9%
Royalty rate per boe	**$ 4.80**	**$ 17.14**	**$ 11.20**	$ 4.38	$ 13.39	$ 9.11

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

Total royalties for Q2/2018 were $77.2 million and averaged 23.4% of total sales, net of blending and other expense, which is higher than $60.0 million and 23.0% for Q2/2017. Total royalties were $142.0 million for YTD 2018 and averaged 23.7% of total sales, net of blending and other expense, as compared to $117.2 million or 22.9% reported for YTD 2017. Higher commodity prices have increased our overall royalty expense and resulted in a slight increase in our average royalty rate during 2018 compared to 2017. Our average royalty rate of 23.7% for YTD 2018 is consistent with our 2018 annual guidance of approximately 23%.

Our Canadian royalty rate averaged 14.0% of total sales, net of blending and other expense, for Q2/2018 and 13.4% for YTD 2018 which is slightly higher than the same periods of 2017 due to higher commodity prices in 2018. In the U.S., royalties for Q2/2018 and YTD 2018 averaged 29.5% and 29.7% of total petroleum and natural gas sales respectively, which is consistent with the comparative periods of 2017 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

Operating Expense

	Three Months Ended June 30					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.[1]**	**Total**	Canada	U.S.[1]	Total
Operating expense	**$ 46,924**	**$ 23,225**	**$ 70,149**	$ 45,981	$ 24,944	$ 70,925
Operating expense per boe	**$ 15.15**	**$ 6.97**	**$ 10.91**	$ 14.74	$ 7.11	$ 10.70

	Six Months Ended June 30					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.[1]**	**Total**	Canada	U.S.[1]	Total
Operating expense	**$ 92,344**	**$ 43,693**	**$ 136,037**	$ 89,384	$ 45,671	$ 135,055
Operating expense per boe	**$ 15.11**	**$ 6.65**	**$ 10.72**	$ 14.63	$ 6.76	$ 10.50

(1) Operating expense related to the Eagle Ford assets includes transportation expense.

Total operating expense was $70.1 million ($10.91/boe) for Q2/2018, which is consistent with $70.9 million ($10.70/boe) for Q2/2017. Operating expense of $10.91/boe for Q2/2018 approximates the midpoint of our annual guidance range of $10.50 - $11.25/boe.

In Canada, operating expense of $46.9 million ($15.15/boe) for Q2/2018, is consistent with $46.0 million ($14.74/boe) for the same period of 2017. Operating expense per boe was slightly higher in Q2/2018 relative to Q2/2017 primarily due to planned facility turnaround maintenance and regulatory inspection activity completed during Q2/2018.

U.S. operating expense of $23.2 million ($6.97/boe) for Q2/2018 was relatively consistent with $24.9 million ($7.11/boe) reported for Q2/2017. The reported amount of our U.S. operating expense expressed in Canadian dollars changes with fluctuations in the CAD/USD exchange rate which was 1.2911 CAD/USD in Q2/2018 as compared to 1.3447 CAD/USD in Q2/2017. Expressed in U.S. dollars, operating expense for our U.S. properties during Q2/2018 was US$5.40/boe which is fairly consistent with US$5.29/boe in Q2/2017.

YTD 2018 operating expense of $136.0 million ($10.72/boe) was slightly higher than $135.1 million ($10.50/boe) for the first six months of 2017. In Canada, YTD 2018 operating expense of $92.3 million ($15.11/boe) is slightly higher than $89.4 million ($14.63/boe) for YTD 2017 due to planned repair and maintenance activities and facility turnarounds completed during YTD 2018. YTD 2018 operating expense in the U.S. of $43.7 million ($6.65/boe) was slightly lower than $45.7 million ($6.76/boe) for YTD 2017 due to a stronger Canadian dollar in YTD 2018 relative to YTD 2017 which reduces the U.S. operating expense expressed in Canadian dollars. Operating expense on our U.S. properties expressed in U.S. dollars was US$5.20/boe for YTD 2018 which is relatively consistent with US$5.07/boe for the first six months of 2017.

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 heavy oil in Canada to pipeline and rail terminals which can vary from period to period depending on hauling distances to optimize sales prices and trucking rates. The following table compares our transportation expense for the three and six months ended June 30, 2018 and 2017.

	Three Months Ended June 30					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Transportation expense	**$ 7,836**	**$ —**	**$ 7,836**	$ 8,973	$ —	$ 8,973
Transportation expense per boe	**$ 2.53**	**$ —**	**$ 1.22**	$ 2.88	$ —	$ 1.35

	Six Months Ended June 30					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Transportation expense	**$ 16,355**	**$ —**	**$ 16,355**	$ 17,015	$ —	$ 17,015
Transportation expense per boe	**$ 2.68**	**$ —**	**$ 1.29**	$ 2.79	$ —	$ 1.32

(1) Transportation expense related to the Eagle Ford assets is included in operating expenses.

Transportation expense was $7.8 million ($1.22/boe) for Q2/2018 which is relatively consistent with $9.0 million ($1.35/boe) for Q2/2017. YTD 2018 transportation expense of $16.4 million ($1.29/boe) is consistent with $17.0 million ($1.32/boe) for YTD 2017 and was slightly below our annual guidance range of $1.35-$1.45/boe for 2018. Gas transportation costs were slightly lower for YTD 2018 relative to YTD 2017 as a result of a change in certain marketing arrangements.

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. We purchase blending diluent to reduce the viscosity and record a blending and other expense. The sales price received for the blended product is recorded as heavy oil sales. Our heavy oil blending and other expense is netted against our heavy oil sales to compare the realized price on our produced volumes to benchmark pricing. Accordingly, our heavy oil sales price realization can fluctuate depending on the quantities and price of blending diluent required to meet pipeline specifications.

Blending and other expense was $18.2 million for Q2/2018 and $35.5 million for YTD 2018 compared, to $16.4 million for Q2/2017 and $26.5 million for the first six months of 2017. The increase in blending and other expense during Q2/2018 and YTD 2018 is due to higher diluent prices combined with an increase in the quantity of diluent required to meet pipeline specifications relative to the same periods of 2017. The density of blending diluent available in YTD 2018 was heavier relative to YTD 2017 which resulted in higher quantities needed for blending in order to meet pipeline specifications.

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, 2018 and 2017.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2018**	2017	Change	**2018**	2017	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ (30,558)**	$ 2,772	$ (33,330)	**$ (40,824)**	$ 3,856	$ (44,680)
Natural gas	**1,150**	(123)	1,273	**1,575**	(933)	2,508
Total	**$ (29,408)**	$ 2,649	$ (32,057)	**$ (39,249)**	$ 2,923	$ (42,172)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ (45,800)**	$ 9,958	$ (55,758)	**$ (63,459)**	$ 35,848	$ (99,307)
Natural gas	**(1,585)**	3,271	(4,856)	**(1,635)**	12,995	(14,630)
Total	**$ (47,385)**	$ 13,229	$ (60,614)	**$ (65,094)**	$ 48,843	$ (113,937)
Total financial derivatives gain (loss)						
Crude oil	**$ (76,358)**	$ 12,730	$ (89,088)	**$ (104,283)**	$ 39,704	$ (143,987)
Natural gas	**(435)**	3,148	(3,583)	**(60)**	12,062	(12,122)
Total	**$ (76,793)**	$ 15,878	$ (92,671)	**$ (104,343)**	$ 51,766	$ (156,109)

Realized financial derivatives losses of $29.4 million for Q2/2018 and $39.2 million for YTD 2018 are primarily a result of the market prices for crude oil settling at levels above those set in our fixed price contracts.

Realized losses of $40.8 million related to our crude oil financial derivatives in place for YTD 2018 were driven by $42.5 million of losses on our WTI swap contracts and $9.1 million of losses on our Brent swap contracts as the market price of WTI and Brent settled above our contract prices. We also recorded $2.5 million of realized losses on our 3-way option contract as the market price of WTI settled above the sold call price during YTD 2018. Losses on WTI and Brent contracts were partially offset by gains of $13.3 million on our WCS differential contracts as the index was wider than the differentials set in our contracts throughout the first six months of 2018.

We recorded realized gains of $1.6 million on our natural gas financial derivatives during YTD 2018. These gains were primarily a result of the AECO price index for the first six months of 2018 averaging lower than the average fixed price on AECO contracts in place for YTD 2018.

At June 30, 2018, the fair value of our financial derivative contracts represent a net liability of $96.7 million compared to a net liability of $31.6 million at December 31, 2017. The net liability of $96.7 million as at June 30, 2018 is primarily a result of futures pricing for WTI and Brent crude oil indices being higher than the prices in our crude oil financial derivatives in place for the remainder of 2018 and 2019.

We had the following commodity financial derivative contracts as at July 30, 2018.

	Period	Volume	Price/Unit[1]	Index
Oil				
Basis swap	Jul 2018 to Dec 2018	6,000 bbl/d	WTI less US$14.24/bbl	WCS
3-way option [2]	Jul 2018 to Dec 2018	2,000 bbl/d	US$60.00/US$54.40/US$40.00	WTI
Fixed - Sell	Jul 2018 to Dec 2018	14,000 bbl/d	US$52.31/bbl	WTI
Fixed - Sell	Jul 2018 to Dec 2018	4,000 bbl/d	US$61.31/bbl	Brent
Fixed - Sell	Jan 2019 to Jun 2019	2,000 bbl/d	US$62.85/bbl	WTI
Fixed - Sell	Jan 2019 to Dec 2019	2,000 bbl/d	US$61.70/bbl	WTI
Swaption [3]	Jan 2019 to Dec 2019	2,000 bbl/d	US$61.70/bbl	WTI
Swaption [3]	Jan 2019 to Dec 2019	2,000 bbl/d	US$59.60/bbl	WTI
3-way option [2]	Jan 2019 to Dec 2019	2,000 bbl/d	US$70.00/US$60.00/US$50.00	WTI
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.50/US$65.50/US$55.50	Brent
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$77.55/US$70.00/US$60.00	Brent
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$83.00/US$73.00/US$63.00	Brent
Natural Gas				
Fixed - Sell	Jul 2018 to Dec 2018	15,000 mmbtu/d	US$3.01	NYMEX
Fixed - Sell	Jul 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO

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

(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$60/US$54.40/US$40 contract, Baytex receives WTI plus US$14.40/bbl when WTI is at or below US$40/bbl; Baytex receives US$54.40/bbl when WTI is between US$40/bbl and US$54.40/bbl; Baytex receives the market price when WTI is between US$54.40/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.

(3) For these contracts, the counterparty has the right, if exercised on December 31, 2018, 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 30, 2018, Baytex had committed to deliver the following volumes of raw bitumen to market on rail:

Period	Volume
Jul 2018 to Dec 2018	8,000 bbl/d
Sep 2018 to Dec 2019	2,500 bbl/d
Jan 2019 to Dec 2020	5,000 bbl/d

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the three and six months ended June 30, 2018 and 2017.

	Three Months Ended June 30					
	2018			2017		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**34,042**	**36,622**	**70,664**	34,284	38,528	72,812
Operating netback:						
Total sales, net of blending and other expense	**$ 41.61**	**$ 60.16**	**$ 51.22**	$ 33.86	$ 44.34	$ 39.41
Less:						
Royalties	**5.81**	**17.77**	**12.01**	4.53	13.09	9.06
Operating expense	**15.15**	**6.97**	**10.91**	14.74	7.11	10.70
Transportation expense	**2.53**	**—**	**1.22**	2.88	—	1.35
Operating netback	**$ 18.12**	**$ 35.42**	**$ 27.08**	$ 11.71	$ 24.14	$ 18.30
Realized financial derivatives (loss) gain	**—**	**—**	**(4.57)**	—	—	0.40
Operating netback after financial derivatives	**$ 18.12**	**$ 35.42**	**$ 22.51**	$ 11.71	$ 24.14	$ 18.70

	Six Months Ended June 30					
	2018			2017		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**33,774**	**36,321**	**70,095**	33,754	37,311	71,065
Operating netback:						
Total sales, net of blending and other expense	**$ 35.73**	**$ 57.76**	**$ 47.15**	$ 33.35	$ 45.59	$ 39.77
Less:						
Royalties	**4.80**	**17.14**	**11.20**	4.38	13.39	9.11
Operating expense	**15.11**	**6.65**	**10.72**	14.63	6.76	10.50
Transportation expense	**2.68**	**—**	**1.29**	2.79	—	1.32
Operating netback	**$ 13.14**	**$ 33.97**	**$ 23.94**	$ 11.55	$ 25.44	$ 18.84
Realized financial derivatives (loss) gain	**—**	**—**	**(3.09)**	—	—	0.23
Operating netback after financial derivatives	**$ 13.14**	**$ 33.97**	**$ 20.85**	$ 11.55	$ 25.44	$ 19.07

Operating netback after financial derivatives of $22.51/boe for Q2/2018 and $20.85/boe for YTD 2018 increased from $18.70/boe for Q2/2017 and $19.07/boe for YTD 2017. The increase in our realized sales price per boe during Q2/2018 and YTD 2018 resulting from higher oil prices was partially offset by higher royalties and slightly higher operating expenses compared to same periods of 2017. The increase in royalty expense per boe is primarily due to higher realized prices in Q2/2018 and YTD 2018. Operating expense per boe was slightly higher in Q2/2018 and YTD 2018 due to planned repair and maintenance activity and facility turnarounds completed during YTD 2018. We recorded realized losses on financial derivatives of $4.57/boe in Q2/2018 and $3.09/boe in YTD 2018 as losses recorded on our WTI and Brent contracts were partially offset by gains recorded on our WCS differential and natural gas contracts.

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 was $1.4 million for Q2/2018 and $3.4 million for YTD 2018 compared to $3.7 million for Q2/2017 and $5.0 million for YTD 2017.

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, 2018 and 2017.

	Three Months Ended June 30					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation[(1)]	**$ 47,602**	**$ 64,262**	**$ 111,864**	$ 52,538	$ 78,617	$ 131,155
Depletion and depreciation per boe	**$ 15.37**	**$ 19.28**	**$ 17.40**	$ 16.84	$ 22.42	$ 19.79

	Six Months Ended June 30					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation[(1)]	**$ 94,771**	**$ 125,382**	**$ 220,153**	$ 103,516	$ 149,970	$ 253,486
Depletion and depreciation per boe	**$ 15.50**	**$ 19.07**	**$ 17.35**	$ 16.94	$ 22.21	$ 19.71

(1) Canada includes corporate depreciation.

Depletion and depreciation expense was $111.9 million ($17.40/boe) for Q2/2018 and $220.2 million ($17.35/boe) for YTD 2018 which is lower than $131.2 million ($19.79/boe) for Q2/2017 and $253.5 million ($19.71/boe) for YTD 2017. In Canada, depletion expense was lower in 2018 compared to 2017 primarily due to a lower depletion rate from an increase in proved plus probable reserve volumes recorded in Q4/2017. The U.S. depletion rate for 2018 is also lower than 2017 due to a lower average CAD/USD exchange rate in 2018 relative to 2017 along with an increase in proved plus probable reserve volumes recorded in Q4/2017.

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

The following table summarizes our G&A expense for the three and six months ended June 30, 2018 and 2017.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for per boe)	**2018**	2017	Change	**2018**	2017	Change
General and administrative expense	**$ 10,563**	$ 14,015	$ (3,452)	**$ 21,571**	$ 26,598	$ (5,027)
General and administrative expense per boe	**$ 1.64**	$ 2.12	$ (0.48)	**$ 1.70**	$ 2.07	$ (0.37)

G&A expense for Q2/2018 and YTD 2018 are lower than the comparative periods of 2017 and are slightly ahead of our 2018 annual guidance of approximately $1.72/boe and $44 million. We reported G&A expense of $10.6 million ($1.64/boe) for Q2/2018 and $21.6 million ($1.70/boe) for YTD 2018 which is lower than $14.0 million ($2.12/boe) for Q2/2017 and $26.6 million ($2.07/boe) for YTD 2017. Reduced staffing levels and our ongoing cost savings efforts have resulted in lower G&A expense in 2018 relative to 2017.

Share-Based Compensation Expense

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

We recorded SBC expense of $3.9 million for Q2/2018 and $7.8 million for YTD 2018 which is down from $5.6 million for Q2/2017 and $10.1 million reported for YTD 2017. SBC expense is lower in 2018 due to a lower fair value assigned to share awards granted in YTD 2018 as compared to awards granted in YTD 2017.

Financing and Interest Expense

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

Financing and interest expense was $28.8 million for Q2/2018 and $56.8 million for YTD 2018 which is slightly lower than $29.3 million reported for Q2/2017 and $57.8 million for YTD 2017. Cash interest expense of $50.0 million for YTD 2018 was slightly lower than $51.1 million reported for the same period of 2017 due to lower reported interest on our long-term notes as a result of a stronger Canadian dollar during YTD 2018 which reduced the amount of U.S. dollar interest reported in Canadian dollars. Cash interest of $50.0 million ($3.94/boe) the first six months of 2018 is consistent with our full year guidance of approximately $100 million and $3.95/boe.

Foreign Exchange

Unrealized foreign exchange gains and losses represent the change in value of the long-term notes and bank loan denominated in U.S. dollars. The long-term notes and bank loan are translated to Canadian dollars on the balance sheet date using the closing CAD/USD exchange rate. When the Canadian dollar strengthens against the U.S. dollar at the end of the current period compared to the previous period an unrealized gain is recorded and conversely when the Canadian dollar weakens at the end of the current period compared to the previous period an unrealized loss is recorded. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in our Canadian operations.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands except for exchange rates)	**2018**	2017	Change	**2018**	2017	Change
Unrealized foreign exchange loss (gain)	**$ 22,673**	$ (32,045)	$ 54,718	**$ 58,719**	$ (43,383)	$ 102,102
Realized foreign exchange loss (gain)	**2,076**	(907)	2,983	**2,247**	(157)	2,404
Foreign exchange loss (gain)	**$ 24,749**	$ (32,952)	$ 57,701	**$ 60,966**	$ (43,540)	$ 104,506
CAD/USD exchange rates:						
At beginning of period	**1.2901**	1.3322		**1.2518**	1.3427	
At end of period	**1.3142**	1.2983		**1.3142**	1.2983	

We recorded an unrealized foreign exchange loss of $22.7 million for Q2/2018 and $58.7 million for YTD 2018 due to a weakening of the Canadian dollar relative to the U.S. dollar. The CAD/USD exchange rate was 1.3142 as at June 30, 2018 compared to 1.2901 as at March 31, 2018 and 1.2518 as 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 $2.2 million for the first six months of 2018 compared to a gain of $0.2 million for the same period of 2017.

Income Taxes

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2018**	2017	Change	**2018**	2017	Change
Current income tax expense (recovery)	**$ 2**	$ (705)	$ 707	**$ (71)**	$ (1,441)	$ 1,370
Deferred income tax expense (recovery)	**(24,561)**	(23,295)	(1,266)	**(47,478)**	(35,740)	(11,738)
Total income tax recovery	**$ (24,559)**	$ (24,000)	$ (559)	**$ (47,549)**	$ (37,181)	$ (10,368)

Current income taxes were nominal for the three and six months ended June 30, 2018 and 2017. During all of these periods, tax pool claims were sufficient to shelter the income associated with our adjusted funds flow.

We recorded a deferred income tax recovery of $24.6 million for Q2/2018 and $47.5 million for YTD 2018 as compared to $23.3 million for Q2/2017 and $35.7 million for YTD 2017. The effect of the increase in adjusted funds flow and decrease in depletion and depreciation were largely offset by an increase in unrealized financial derivative losses and resulted in a higher deferred income tax recovery in Q2/2018 and YTD 2018 compared to the same periods of 2017.

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the "CRA") that deny non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. These reassessments followed a previously disclosed letter which we received in November 2014 from the CRA, proposing to issue such reassessments.

We remain confident that the tax filings of the affected entities are correct and are defending our tax filing positions. The reassessments do not require us to pay any amounts in order to participate in the appeals process.

In September 2016, we filed a notice of objection for each notice of reassessment received which will be reviewed by the Appeals Division of the CRA. An Appeals Officer was assigned to our file in July 2018 and we estimate the appeals process could take up to one year. If the Appeals Division upholds the notices of reassessment, we have the right to appeal to the Tax Court of Canada; a process that we estimate could take a further two years. Should we be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that we estimate could take another two years and potentially longer.

By way of background, we acquired several privately held commercial trusts in 2010 with accumulated non-capital losses of $591 million (the "Losses"). The Losses were subsequently used to reduce the taxable income of those trusts. The reassessments disallow the deduction of the Losses under the general anti-avoidance rule of the Income Tax Act (Canada). If, after exhausting available appeals, the deduction of Losses continues to be disallowed, we will owe cash taxes for the years 2012 through 2015 and an additional amount for late payment interest. The amount of cash taxes owing and the late payment interest are dependent upon the amount of unused tax shelter available to offset the reassessed income, including tax shelter from future years available to recover taxes paid in the years 2012 through 2015.

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, 2018 and 2017 are set forth in the following table.

	Three Months Ended June 30			Six Months Ended June 30		
($ thousands)	**2018**	2017	Change	**2018**	2017	Change
Petroleum and natural gas sales	**$ 347,605**	$ 277,536	$ 70,069	**$ 633,672**	$ 538,085	$ 95,587
Royalties	**(77,205)**	(60,014)	(17,191)	**(142,044)**	(117,191)	(24,853)
Revenue, net of royalties	**270,400**	217,522	52,878	**491,628**	420,894	70,734
Expenses						
Operating	**(70,149)**	(70,925)	776	**(136,037)**	(135,055)	(982)
Transportation	**(7,836)**	(8,973)	1,137	**(16,355)**	(17,015)	660
Blending and other	**(18,239)**	(16,427)	(1,812)	**(35,529)**	(26,484)	(9,045)
Operating netback	**$ 174,176**	$ 121,197	$ 52,979	**$ 303,707**	$ 242,340	$ 61,367
General and administrative	**(10,563)**	(14,015)	3,452	**(21,571)**	(26,598)	5,027
Cash financing and interest	**(25,530)**	(25,915)	385	**(50,041)**	(51,107)	1,066
Realized financial derivatives (loss) gain	**(29,408)**	2,649	(32,057)	**(39,249)**	2,923	(42,172)
Realized foreign exchange loss	**(2,076)**	907	(2,983)	**(2,247)**	157	(2,404)
Other income (expense)	**288**	(493)	781	**567**	(906)	1,473
Current income tax (expense) recovery	**(2)**	705	(707)	**71**	1,441	(1,370)
Payments on onerous contracts	**(195)**	(1,899)	1,704	**(292)**	(3,745)	3,453
Adjusted funds flow	**$ 106,690**	$ 83,136	$ 23,554	**$ 190,945**	$ 164,505	$ 26,440
Exploration and evaluation	**(1,358)**	(3,686)	2,328	**(3,377)**	(5,008)	1,631
Depletion and depreciation	**(111,864)**	(131,155)	19,291	**(220,153)**	(253,486)	33,333
Share based compensation	**(3,915)**	(5,593)	1,678	**(7,830)**	(10,142)	2,312
Non-cash financing and accretion	**(3,256)**	(3,378)	122	**(6,755)**	(6,692)	(63)
Unrealized financial derivatives (loss) gain	**(47,385)**	13,229	(60,614)	**(65,094)**	48,843	(113,937)
Unrealized foreign exchange (loss) gain	**(22,673)**	32,045	(54,718)	**(58,719)**	43,383	(102,102)
Gain (loss) on disposition of oil and gas properties	**244**	(524)	768	**1,730**	(524)	2,254
Deferred income tax (expense) recovery	**24,561**	23,295	1,266	**47,478**	35,740	11,738
Payments on onerous contracts	**195**	1,899	(1,704)	**292**	3,745	(3,453)
Net income (loss) for the period	**$ (58,761)**	$ 9,268	$ (68,029)	**$ (121,483)**	$ 20,364	$ (141,847)

We generated adjusted funds flow of $106.7 million for Q2/2018, an increase of $23.6 million from adjusted funds flow of $83.1 million reported for Q2/2017. The increase in adjusted funds flow in the second quarter of 2018 was primarily due to a higher operating netback which increased by $53.0 million from the same period in 2017. The increase in operating netback was due to higher commodity prices which increased revenues and was partially offset by higher royalties in Q2/2018 as compared to Q2/2017 along with a $32.1 million increase in realized hedging losses.

In Q2/2018, we recorded a net loss of $58.8 million compared to income of $9.3 million for the same period of 2017. The net loss recorded for Q2/2018 includes an unrealized loss on financial derivatives of $47.4 million, representing a $60.6 million change from an unrealized gain of $13.2 million recorded for Q2/2017. We also recorded an unrealized foreign exchange loss of $22.7 million in Q2/2018 as compared to an unrealized gain of $32.0 million in the same period of 2017. This was offset by a $19.3 million reduction in depletion and depreciation expense recorded for Q2/2018 relative to Q2/2017.

Adjusted funds flow of $190.9 million for YTD 2018 was $26.4 million higher than $164.5 million for YTD 2017. The increase in adjusted funds flow for YTD 2018 was driven by higher commodity prices which resulted in a $70.7 million increase in revenue, net of royalties as compared to YTD 2017. Operating netback for YTD 2018 was $61.4 million higher than YTD 2017 as the increase in revenue, net of royalties, was partially offset by a $9.0 million increase in blending and other expense. We recorded realized financial derivative losses of $39.2 million in YTD 2018 as compared to gains of $2.9 million for YTD 2017 which reduced the increase in operating netbacks by $42.2 million.

We recorded a net loss of $121.5 million for YTD 2018 as compared to net income of $20.4 million reported for the same period of 2017. The change in net income was primarily a result of strengthening commodity prices which impacted the valuation of our commodity price derivatives and resulted in a $65.1 million unrealized loss on financial derivatives for YTD 2018 as compared to a $48.8 million gain for YTD 2017. We also recorded an unrealized foreign exchange loss of $58.7 million related to the weakening of the Canadian dollar during YTD 2018 which impacted the carrying value of our long-term notes. These factors combined to more than offset the increase in adjusted funds flow and resulted in a $141.8 million change in net income (loss) reported for YTD 2018 as compared to YTD 2017.

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 $116.5 million foreign currency translation gain for the six months ended June 30, 2018 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the weakening of the Canadian dollar against the U.S. dollar over the same period. The CAD/USD exchange rate was 1.3142 as at June 30, 2018 compared to 1.2518 as at December 31, 2017.

Capital Expenditures

Capital expenditures for the three and six months ended June 30, 2018 and 2017 are summarized as follows.

	Three Months Ended June 30					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land and seismic	**$ 1,277**	**$ —**	**$ 1,277**	$ 1,195	$ —	$ 1,195
Drilling, completion and equipping	**9,193**	**45,945**	**55,138**	12,834	54,701	67,535
Facilities	**19,378**	**2,175**	**21,553**	4,410	4,867	9,277
Other	**760**	**102**	**862**	—	—	—
Total exploration and development	**$ 30,608**	**$ 48,222**	**$ 78,830**	$ 18,439	$ 59,568	$ 78,007
Total acquisitions, net of proceeds from divestitures	**(21)**	**—**	**(21)**	5,226	—	5,226
Total oil and natural gas expenditures	**$ 30,587**	**$ 48,222**	**$ 78,809**	$ 23,665	$ 59,568	$ 83,233

	Six Months Ended June 30					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land and seismic	**$ 3,335**	**$ —**	**$ 3,335**	$ 2,811	$ —	$ 2,811
Drilling, completion and equipping	**42,736**	**81,116**	**123,852**	48,111	110,060	158,171
Facilities	**32,368**	**9,013**	**41,381**	5,999	7,585	13,584
Other	**3,694**	**102**	**3,796**	—	—	—
Total exploration and development	**$ 82,133**	**$ 90,231**	**$ 172,364**	$ 56,921	$ 117,645	$ 174,566
Total acquisitions, net of proceeds from divestitures	**(2,047)**	**—**	**(2,047)**	71,230	—	71,230
Total oil and natural gas expenditures	**$ 80,086**	**$ 90,231**	**$ 170,317**	$ 128,151	$ 117,645	$ 245,796

We invested $78.8 million in exploration and development activities during Q2/2018 which is $0.8 million higher than exploration and development expenditures of $78.0 million for Q2/2017. Our Q2/2018 capital program was focused on maintaining the pace of development on our heavy oil properties in Canada and our properties in the Eagle Ford.

Total exploration and development expenditures in Canada were $30.6 million for Q2/2018 compared to $18.4 million in Q2/2017. We drilled 13 (4.3 net) wells and spent $9.2 million on drilling, completion and equipping costs during Q2/2018 compared to drilling eight (5.9 net) wells during Q2/2017 for $12.8 million. At Peace River, we drilled one (1.0 net) well and commenced production from four (4.0 net) wells during Q2/2018. Our first multi-lateral horizontal well on our northern Seal acreage (acquired in January 2017) commenced production during Q2/2018 and established a 30-day initial production rate of approximately 918 boe/d. The second multi-lateral horizontal well on our northern Seal acreage was brought online at the end of June and recently established a 30-day initial production rate of approximately 660 boe/d. Drilling operations at Lloydminster included 12 (3.3 net) wells drilled during Q2/2018. Facilities spending of $19.4 million during Q2/2018 includes costs for the construction of a gas plant and strategic infrastructure projects including pipeline expansions to support growth at Peace River.

In the U.S., capital spending of $48.2 million in Q2/2018 was $11.3 million lower than $59.6 million during Q2/2017 due to lower drilling and completion activity on our lands in Q2/2018 relative to the comparative period. We participated in the drilling of 18 (2.6 net) wells and initiated production from 32 (7.6 net) wells during Q2/2018 compared to 38 (9.4 net) wells drilled and 35 (8.1 net) wells on production in the same period of 2017.

Exploration and development expenditures of $172.4 million for YTD 2018 are $2.2 million lower than $174.6 million reported for the first six months of 2017. In Canada, drilling, completion and equipping costs of $42.7 million were $5.4 million lower than $48.1 million reported for YTD 2017 as a higher portion of our capital activity during YTD 2018 was in our Lloydminster division as opposed to YTD 2017 when our capital activity was focused on Peace River. During YTD 2018 we invested $32.4 million on facilities in Canada including construction of a gas plant and strategic infrastructure projects which is up $26.4 million from $6.0 million during the first six months of 2017. In the U.S., exploration and development expenditures of $90.2 million for YTD 2018 were $27.4 million lower than $117.6 million during YTD 2017 due to lower drilling and completion activity on our lands during YTD 2018 relative to YTD 2017. We drilled 43 (9.5 net) wells and initiated production from 59 (13.1 net) wells during YTD 2018 as compared to 74 (17.8 net) wells drilled and 68 (17.5 net) wells brought on production during YTD 2017. Wells on production during YTD 2018 had longer completed lengths and increased proppant concentration which resulted in a slight increase in average well costs relative to YTD 2017.

We completed minor acquisition and disposition activity in YTD 2018 for net proceeds of $2.0 million compared to YTD 2017 when our acquisition and disposition activities were primarily comprised of the Peace River acquisition which totaled $66.1 million.

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, 2018, our capital structure was comprised of shareholders' capital, long-term debt, 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. Our adjusted funds flow is dependent 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, 2018, net debt was $1,784.8 million, an increase of $50.5 million from $1,734.3 million at December 31, 2017. The weakening of the Canadian dollar relative to the U.S. dollar increased the reported amount of our U.S. dollar denominated debt at June 30, 2018 by $59.3 million.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio. At June 30, 2018, our net debt to adjusted funds flow ratio was 4.1 compared to a ratio of 5.0 as at December 31, 2017. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2017 is attributed to higher adjusted funds flow from higher operating netbacks after derivatives losses which more than offset the impact of the increase in net debt as at June 30, 2018 due to a weakening of the Canadian dollar relative to the U.S. dollar.

Bank Loan

At June 30, 2018, the principal amount of bank loan outstanding was $213.5 million and we had approximately $522.5 million of available capacity under the credit facility agreement.

On April 25, 2018, Baytex amended its credit facilities to extend maturity from June 4, 2019 to June 4, 2020 and elected to end the covenant relief period early to benefit from reduced borrowing costs. The amended revolving extendible secured credit facilities are comprised of a US$35 million operating loan (previously US$25 million) and a US$340 million syndicated loan (previously $350 million) for Baytex and a US$200 million syndicated loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities").

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants, including the financial covenants detailed below, and do not require any mandatory principal payments prior to maturity on June 4, 2020. Baytex may request an extension of the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year period at any time). Advances (including letters of credit) under the Revolving 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 Revolving 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 relating to the Revolving Facilities are accessible on the SEDAR website at www.sedar.com (filed under the category "Material contracts - Credit agreements" on April 13, 2016 and May 2, 2018).

The weighted average interest rate on the credit facilities for Q2/2018 was 4.4% as compared to 4.0% for Q2/2017.

Financial Covenants

On April 25, 2018, we amended the Revolving Facilities and elected to end the covenant relief period early. The following table summarizes the financial covenants applicable to the Revolving Facilities and our compliance therewith at June 30, 2018.

Covenant Description	Position as at June 30, 2018	Ratio for the quarter ended June 30, 2018 and thereafter
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.57:1.00**	3.50:1.00
Interest Coverage(3) (Minimum Ratio)	**4.05:1.00**	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, 2018, the Company's Senior Secured Debt totaled $228.7 million.

(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, 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. Bank EBITDA for the twelve months ended June 30, 2018 was $402.7 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, 2018 were $99.4 million.

Long-Term Notes

We have four series of long-term notes outstanding that total $1.55 billion as at June 30, 2018. 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 2.5:1.0. As at June 30, 2018, the fixed charge coverage ratio was 4.05:1.00.

On February 17, 2011, we issued US$150 million principal amount of senior unsecured notes bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. As of February 17, 2016, these notes are redeemable at our option, in whole or in part, at specified redemption prices.

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

On June 6, 2014, we issued US$800 million of senior unsecured notes, comprised of US$400 million of 5.125% notes due June 1, 2021 (the "5.125% Notes") and US$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"). The 5.125% Notes and the 5.625% Notes pay interest semi-annually with the principal amount repayable at maturity. As of June 1, 2017, the 5.125% Notes are redeemable at our option, in whole or in part, at specified redemption prices. The 5.625% Notes are redeemable at our option, in whole or in part, commencing on June 1, 2019 at specified redemption prices.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the six months ended June 30, 2018, we issued 1.2 million common shares pursuant to our share-based compensation program. As at July 30, 2018, we had 236.7 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, 2018 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	**$ 165,062**	$ 165,062	$ —	$ —	$ —
Bank loan[1] [2]	**213,538**	—	213,538	—	—
Long-term notes[2]	**1,548,490**	—	722,810	300,000	525,680
Interest on long-term notes[3]	**369,520**	89,692	172,505	80,103	27,220
Operating leases	**25,023**	6,841	12,560	5,622	—
Processing agreements	**48,999**	9,193	16,352	9,004	14,450
Transportation agreements	**29,719**	1,417	19,070	8,614	618
Total	**$ 2,400,351**	$ 272,205	$ 1,156,835	$ 403,343	$ 567,968

(1) The bank loan is covenant-based with a revolving period that is extendible annually for up to a four-year term. Unless extended, the revolving period will end on June 4, 2020, with all amounts to be repaid on such date.
(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

	2018		2017				2016	
($ thousands, except per common share amounts)	Q2	Q1	Q4	Q3	Q2	Q1	Q4	Q3
Petroleum and natural gas sales	**347,605**	286,067	303,163	258,620	277,536	260,549	233,116	197,648
Net income (loss)	**(58,761)**	(62,722)	76,038	(9,228)	9,268	11,096	(359,424)	(39,430)
Per common share - basic	**(0.25)**	(0.27)	0.32	(0.04)	0.04	0.05	(1.66)	(0.19)
Per common share - diluted	**(0.25)**	(0.27)	0.32	(0.04)	0.04	0.05	(1.66)	(0.19)
Adjusted funds flow	**106,690**	84,255	105,796	77,340	83,136	81,369	77,239	72,106
Per common share - basic	**0.45**	0.36	0.45	0.33	0.35	0.35	0.36	0.34
Per common share - diluted	**0.45**	0.36	0.44	0.33	0.35	0.34	0.36	0.34
Exploration and development	**78,830**	93,534	90,156	61,544	78,007	96,559	68,029	39,579
Canada	**30,608**	51,525	41,864	14,487	18,439	38,484	12,151	6,120
U.S.	**48,222**	42,009	48,292	47,057	59,568	58,075	55,878	33,459
Acquisitions, net of divestitures	**(21)**	(2,026)	(3,937)	(7,436)	5,226	66,004	(322)	(62,752)
Net debt	**1,784,835**	1,783,379	1,734,284	1,748,805	1,819,387	1,850,909	1,773,541	1,864,022
Total assets	**4,476,906**	4,433,074	4,372,111	4,353,637	4,582,049	4,702,423	4,594,085	4,995,876
Common shares outstanding	**236,662**	236,578	235,451	235,451	234,204	234,203	233,449	211,542
Daily production								
Total production (boe/d)	**70,664**	69,522	69,556	69,310	72,812	69,298	65,136	67,167
Canada (boe/d)	**34,042**	33,505	32,194	34,560	34,284	33,217	31,704	33,615
U.S. (boe/d)	**36,622**	36,017	37,362	34,750	38,528	36,081	33,432	33,552
Benchmark prices								
WTI oil (US$/bbl)	**67.88**	62.87	55.40	48.20	48.28	51.91	49.29	44.94
WCS heavy (US$/bbl)	**48.61**	38.59	43.14	38.26	37.16	37.34	34.97	31.44
CAD/USD avg exchange rate	**1.2911**	1.2651	1.2717	1.2524	1.3447	1.3229	1.3339	1.3051
AECO gas ($/mcf)	**1.03**	1.85	1.96	2.04	2.77	2.94	2.81	2.20
NYMEX gas (US$/mmbtu)	**2.80**	3.00	2.93	3.00	3.18	3.32	2.98	2.81
Sales price ($/boe)	**51.22**	42.96	44.75	38.04	39.41	40.16	38.16	31.73
Royalties ($/boe)	**12.01**	10.36	10.86	8.65	9.06	9.17	9.28	7.37
Operating expense ($/boe)	**10.91**	10.53	10.91	10.10	10.70	10.28	9.96	9.07
Transportation expense ($/boe)	**1.22**	1.36	1.20	1.46	1.35	1.29	1.30	1.38
Operating netback ($/boe)	**27.08**	20.71	21.78	17.83	18.30	19.42	17.62	13.91
Financial derivatives (loss) gain ($/boe)	**(4.57)**	(1.57)	0.30	0.44	0.40	0.04	1.62	3.04
Operating netback after financial derivatives ($/boe)	**22.51**	19.14	22.08	18.27	18.70	19.46	19.24	16.95

Our operating and financial results have improved as oil prices continue to recover from the multi-year lows experienced in 2016. Compliance with OPEC's production quotas and increased global demand for crude oil have resulted in the WTI benchmark gradually increasing from US$44.94/bbl in Q3/2016 to US$67.88/bbl during Q2/2018. We maintained the pace of exploration and development expenditures in the Eagle Ford as these assets generate our highest netbacks and rates of return. In Canada, exploration and development activity increased in 2017 after deferring operated heavy oil drilling during the first three quarters of 2016 in response to low heavy oil prices. The increased level of activity has increased production from Q4/2016 into Q2/2018. Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow improved in late 2017 as commodity prices recovered and our daily production increased from 2016.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt has decreased from $1,864.0 million at Q3/2016 to $1,784.8 million at Q2/2018 primarily due to adjusted funds flow exceeding our exploration and development spending over the last eight quarters as the CAD/USD exchange rate and the amount of our U.S. dollar denominated debt was relatively consistent at June 30, 2018 and September 30, 2016.

2018 GUIDANCE

The following table compares our 2018 annual guidance compared to our YTD 2018 results. We will update our 2018 annual guidance on closing of the Arrangement, which we expect to occur on August 22, 2018.

	Guidance	YTD 2018	Variance
Exploration and development capital	$325-$375 million	$172.4 million	— %
Production (boe/d)	68,000 to 72,000	70,095	— %
Expenses:			
Royalty rate	~ 23%	23.7%	1 %
Operating	$10.50-$11.25/boe	$10.72/boe	— %
Transportation	$1.35-$1.45/boe	$1.29/boe	(4)%
General and administrative	~ $44 million ($1.72/boe)	$21.6 million ($1.70/boe)	(1)%
Interest	~ $100 million ($3.95/boe)	$50.0 million ($3.94/boe)	— %

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at June 30, 2018, 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, 2018. 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, 2017.

CHANGES IN ACCOUNTING STANDARDS

Revenue Recognition

Baytex adopted IFRS 15 *Revenue from Contracts with Customers* with a date of initial application of January 1, 2018. For the year ended December 31, 2017, $8.3 million of commodity purchases related to heavy oil sales have been reclassified from petroleum and natural gas sales to blending and other expense to conform with the requirements of IFRS 15. There were no adjustments made to the January 1, 2018 opening statement of financial position on adoption. The additional disclosures required by IFRS 15 are provided in note 11 to the consolidated financial statements.

The nature of the Company's performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal. Baytex recognizes revenue on a gross basis when it acts as the principal and has primary responsibility for the transaction. Revenue is recognized on a net basis if Baytex acts in the capacity of an agent rather than as a principal.

Revenue from the sale of heavy oil, light oil and condensate, natural gas liquids, and natural gas is recognized based on the consideration specified in contracts with customers. Baytex recognizes revenue when control of the product transfers to the customer and collection is reasonably assured. The amount of revenue recognized is based on the consideration specified in the contract. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon and collection is reasonably assured.

The transaction price for variable price contracts in the Canada and U.S. segments is based on a representative commodity price index, and may be adjusted for quality, location, delivery method, or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantities of oil or natural gas transferred to customers. Market conditions, which impact the Company's ability to negotiate certain components of the transaction price, can also cause the amount of revenue recorded to fluctuate from period to period.

Tariffs, tolls and fees charged to other entities for use of pipelines and facilities owned by Baytex are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Financial Instruments

Baytex adopted IFRS 9 *Financial Instruments*, on January 1, 2018 using the retrospective method. The adoption of this standard did not result in a change in the recognition or measurement of any of the Company's financial instruments on transition.

IFRS 9 contains three principal classification categories for initial classification of financial assets: measured at amortized cost; fair value through other comprehensive income (“FVOCI”); or fair value through profit or loss (“FVTPL”). The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. Financial assets are categorized based on the Company’s objective for the asset and the subsequent cash flows. A financial asset is classified as amortized cost if the asset is held with the objective to collect contractual cash flows that are solely payments of principal and interest on principal amounts outstanding. A financial asset is classified as FVOCI if the asset is held with the objective to both collect contractual cash flows and sell the financial asset. All other financial assets are measured at FVTPL. Financial assets are assessed for impairment using an expected credit loss model. Trade and other receivables are classified and measured at amortized cost.

The initial classification of financial liabilities under IFRS 9 is fundamentally unchanged from the requirements under IAS 39. A financial liability is measured at amortized cost or FVTPL. A financial liability is measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL at initial recognition. For liabilities measured at FVTPL, any change in value resulting from a change in Baytex’s credit-risk is recorded through other comprehensive income or loss rather than net income or loss. Trade and other payables, bank loan and long-term notes are classified and measured as amortized cost.

Future accounting pronouncements

A description of accounting standards that will be effective in the future is included in the notes to the consolidated financial statements.

NON-GAAP AND CAPITAL MEASUREMENT MEASURES

In this MD&A, we refer to certain measures (such as adjusted funds flow, net debt, operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by GAAP. While adjusted funds flow, net debt, operating netback and Bank EBITDA are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. We believe that inclusion of these non-GAAP 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 capital investments, 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 changes in non-cash working capital and 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. Adjusted funds flow should not be construed as an alternative to performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income or loss.

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

	Three Months Ended June 30		Six Months Ended June 30	
($ thousands)	**2018**	2017	**2018**	2017
Cash flow from operating activities	**$ 74,538**	$ 70,241	**$ 162,150**	$ 150,973
Change in non-cash working capital	**29,228**	10,427	**22,608**	5,637
Asset retirement obligations settled	**2,924**	2,468	**6,187**	7,895
Adjusted funds flow	**$ 106,690**	$ 83,136	**$ 190,945**	$ 164,505

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.

The following table summarizes our calculation of net debt.

($ thousands)		**June 30, 2018**		December 31, 2017
Bank loan[1]	**$**	**213,538**	$	213,376
Long-term notes[1]		**1,548,490**		1,489,210
Working capital (surplus) deficiency[2]		**22,807**		31,698
Net debt	**$**	**1,784,835**	$	1,734,284

(1) Principal amount of instruments expressed in Canadian dollars.
(2) Working capital is calculated as current assets less current liabilities (excluding current financial derivatives and onerous contracts).

Operating Netback

We define operating netback as petroleum and natural gas sales, less blending and other 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.

	Three Months Ended June 30				Six Months Ended June 30			
($ thousands)		**2018**		2017		**2018**		2017
Petroleum and natural gas sales	**$**	**347,605**	$	277,536	**$**	**633,672**	$	538,085
Blending and other expense		**(18,239)**		(16,427)		**(35,529)**		(26,484)
Total sales, net of blending and other expense		**329,366**		261,109		**598,143**		511,601
Less:								
Royalties		**77,205**		60,014		**142,044**		117,191
Operating expense		**70,149**		70,925		**136,037**		135,055
Transportation expense		**7,836**		8,973		**16,355**		17,015
Operating netback		**174,176**		121,197		**303,707**		242,340
Realized financial derivative gain (loss)		**(29,408)**		2,649		**(39,249)**		2,923
Operating netback after realized financial derivatives gain (loss)	**$**	**144,768**	$	123,846	**$**	**264,458**	$	245,263

Bank EBITDA

Bank EBITDA is used to assess compliance with certain financial covenants. The following table reconciles net income or loss to Bank EBITDA.

	Three Months Ended June 30				Six Months Ended June 30			
($ thousands)		**2018**		2017		**2018**		2017
Net income (loss)	**$**	**(58,761)**	$	9,268	**$**	**(121,483)**	$	20,364
Plus:								
Financing and interest		**28,786**		29,293		**56,796**		57,799
Unrealized foreign exchange (gain) loss		**22,673**		(32,045)		**58,719**		(43,383)
Unrealized financial derivatives (gain) loss		**47,385**		(13,229)		**65,094**		(48,843)
Current income tax expense (recovery)		**2**		(705)		**(71)**		(1,441)
Deferred income tax recovery		**(24,561)**		(23,295)		**(47,478)**		(35,740)
Depletion and depreciation		**111,864**		131,155		**220,153**		253,486
Gain on disposition of oil and gas properties		**(244)**		524		**(1,730)**		524
Non-cash items[1]		**5,273**		9,279		**11,207**		15,150
Bank EBITDA	**$**	**132,417**	$	110,245	**$**	**241,207**	$	217,916

(1) Non-cash items include share-based compensation, exploration and evaluation expense and non-cash other 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, 2018.

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; the strategic combination of Baytex and Raging River, including that the combined enterprise will be well-capitalized and oil-weighted with core assets across North America, the timing of the shareholder meetings and the expected closing date; our annual average production rate for 2018; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; that increased crude by rail volumes will mitigate the recent widening of the price differential for WCS; our ability to reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; the length of time it would take to resolve the reassessments; that we would owe cash taxes and late payment interest if the reassessment is successful; that our investment in a gas plant and strategic infrastructure at Peace River will support future growth; 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; the existence, operation and strategy of our risk management program; our capital budget for 2018; our plans for developing our properties; and our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2018. 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 the reserves can be profitably produced in the future.

These forward-looking statements are based on certain key assumptions regarding, among other things: the timing of receipt of regulatory and shareholder approvals for the Transaction; the ability of the combined company to realize the anticipated benefits of the Transaction; 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: completion of the Transaction could be delayed if parties are unable to obtain the necessary regulatory, stock exchange, shareholder and court approvals on the timeline planned; the Transaction will not be completed if all of these approvals are not obtained or some other condition of closing is not satisfied; the volatility of oil and natural gas prices; a decline or an extended period of the currently low oil and natural gas prices; uncertainties in the capital markets that may restrict or increase our cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; availability and cost of gathering, processing and pipeline systems; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum 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; we may lose access to our 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, 2017, 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		June 30, 2018		December 31, 2017
ASSETS				
Current assets				
Trade and other receivables	$	**142,255**	$	112,844
Financial derivatives (note 17)		**10,388**		18,510
		152,643		131,354
Non-current assets				
Exploration and evaluation assets (note 5)		**272,168**		272,974
Oil and gas properties (note 6)		**4,043,454**		3,958,309
Other plant and equipment		**8,641**		9,474
	$	**4,476,906**	$	4,372,111
LIABILITIES				
Current liabilities				
Trade and other payables	$	**165,062**	$	144,542
Financial derivatives (note 17)		**100,980**		50,095
Onerous contracts		**2,282**		2,574
		268,324		197,211
Non-current liabilities				
Bank loan (note 7)		**212,387**		212,138
Long-term notes (note 8)		**1,534,309**		1,474,184
Asset retirement obligations (note 9)		**373,863**		368,995
Deferred income tax liability		**164,248**		204,698
Financial derivatives (note 17)		**6,087**		—
		2,559,218		2,457,226
SHAREHOLDERS' EQUITY				
Shareholders' capital (note 10)		**4,452,301**		4,443,576
Contributed surplus		**15,104**		15,999
Accumulated other comprehensive income		**579,560**		463,104
Deficit		**(3,129,277)**		(3,007,794)
		1,917,688		1,914,885
	$	**4,476,906**	$	4,372,111

Subsequent event (note 18)

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) (unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Revenue, net of royalties				
Petroleum and natural gas sales (note 11)	**$ 347,605**	$ 277,536	**$ 633,672**	$ 538,085
Royalties	**(77,205)**	(60,014)	**(142,044)**	(117,191)
	270,400	217,522	**491,628**	420,894
Expenses				
Operating	**70,149**	70,925	**136,037**	135,055
Transportation	**7,836**	8,973	**16,355**	17,015
Blending and other	**18,239**	16,427	**35,529**	26,484
General and administrative	**10,563**	14,015	**21,571**	26,598
Exploration and evaluation (note 5)	**1,358**	3,686	**3,377**	5,008
Depletion and depreciation	**111,864**	131,155	**220,153**	253,486
Share-based compensation (note 12)	**3,915**	5,593	**7,830**	10,142
Financing and interest (note 15)	**28,786**	29,293	**56,796**	57,799
Financial derivatives loss (gain) (note 17)	**76,793**	(15,878)	**104,343**	(51,766)
Foreign exchange loss (gain) (note 16)	**24,749**	(32,952)	**60,966**	(43,540)
(Gain) loss on disposition of oil and gas properties	**(244)**	524	**(1,730)**	524
Other (income) expense	**(288)**	493	**(567)**	906
	353,720	232,254	**660,660**	437,711
Net income (loss) before income taxes	**(83,320)**	(14,732)	**(169,032)**	(16,817)
Income tax expense (recovery) (note 14)				
Current income tax expense (recovery)	**2**	(705)	**(71)**	(1,441)
Deferred income tax expense (recovery)	**(24,561)**	(23,295)	**(47,478)**	(35,740)
	(24,559)	(24,000)	**(47,549)**	(37,181)
Net income (loss) attributable to shareholders	**$ (58,761)**	$ 9,268	**$ (121,483)**	$ 20,364
Other comprehensive income (loss)				
Foreign currency translation adjustment	**44,134**	(62,163)	**116,456**	(80,326)
Comprehensive income (loss)	**$ (14,627)**	$ (52,895)	**$ (5,027)**	$ (59,962)
Net income (loss) per common share (note 13)				
Basic	**$ (0.25)**	$ 0.04	**$ (0.51)**	$ 0.09
Diluted	**$ (0.25)**	$ 0.04	**$ (0.51)**	$ 0.09
Weighted average common shares (note 13)				
Basic	**236,628**	234,204	**236,472**	234,112
Diluted	**236,628**	236,615	**236,472**	236,715

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, 2016	$ 4,422,661	$ 21,405	$ 629,863	$ (3,094,968)	**$ 1,978,961**
Vesting of share awards	9,469	(9,469)	—	—	**—**
Share-based compensation	—	10,142	—	—	**10,142**
Comprehensive income (loss) for the period	—	—	(80,326)	20,364	**(59,962)**
Balance at June 30, 2017	$ 4,432,130	$ 22,078	$ 549,537	$ (3,074,604)	**$ 1,929,141**
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**

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	
	2018	2017	**2018**	2017
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income (loss) for the period	**$ (58,761)**	$ 9,268	**$ (121,483)**	$ 20,364
Adjustments for:				
Share-based compensation (note 12)	**3,915**	5,593	**7,830**	10,142
Unrealized foreign exchange loss (gain) (note 16)	**22,673**	(32,045)	**58,719**	(43,383)
Exploration and evaluation (note 5)	**1,358**	3,686	**3,377**	5,008
Depletion and depreciation	**111,864**	131,155	**220,153**	253,486
Non-cash financing and accretion (note 15)	**3,256**	3,378	**6,755**	6,692
Unrealized financial derivatives loss (gain) (note 17)	**47,385**	(13,229)	**65,094**	(48,843)
(Gain) loss on disposition of capital properties	**(244)**	524	**(1,730)**	524
Deferred income tax recovery	**(24,561)**	(23,295)	**(47,478)**	(35,740)
Payments on onerous contracts	**(195)**	(1,899)	**(292)**	(3,745)
Asset retirement obligations settled (note 9)	**(2,924)**	(2,468)	**(6,187)**	(7,895)
Change in non-cash working capital	**(29,228)**	(10,427)	**(22,608)**	(5,637)
	74,538	70,241	**162,150**	150,973
Financing activities				
Increase (decrease) in bank loan	**(1,127)**	6,739	**(5,043)**	79,481
	(1,127)	6,739	**(5,043)**	79,481
Investing activities				
Additions to exploration and evaluation assets (note 5)	**(115)**	(1,052)	**(1,402)**	(4,837)
Additions to oil and gas properties (note 6)	**(78,715)**	(76,955)	**(170,962)**	(169,729)
Additions to other plant and equipment	**(507)**	(514)	**(507)**	(618)
Property acquisitions (note 6)	**—**	(5,526)	**(187)**	(71,610)
Proceeds from disposition of capital properties (note 5 & 6)	**21**	300	**2,234**	380
Change in non-cash working capital	**5,905**	6,085	**13,717**	15,624
	(73,411)	(77,662)	**(157,107)**	(230,790)
Change in cash	**—**	(682)	**—**	(336)
Cash, beginning of period	**—**	3,051	**—**	2,705
Cash, end of period	**$ —**	$ 2,369	**$ —**	$ 2,369
Supplementary information				
Interest paid	**$ 30,822**	$ 30,775	**$ 49,698**	$ 50,194
Income taxes paid (recovered)	**$ (97)**	$ 386	**$ (81)**	$ 872

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.

The audited consolidated financial statements of the Company as at and for the year ended December 31, 2017 are available through its filings on SEDAR at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov.

2. BASIS OF PRESENTATION

The condensed consolidated interim unaudited financial statements ("consolidated financial statements") have been prepared in accordance with International Accounting Standards 34, Interim Financial Reporting, under International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). These consolidated financial statements do not include all the necessary annual disclosures as prescribed by IFRS and should be read in conjunction with the annual audited consolidated financial statements as at and for the year ended December 31, 2017.

The consolidated financial statements were approved by the Board of Directors of Baytex on July 30, 2018.

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.

3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies, critical accounting judgments and significant estimates used in preparation of the 2017 annual financial statements have been applied in the preparation of these consolidated financial statements, except for the adoption of IFRS 15 *Revenue from Contracts with Customers* and IFRS 9 *Financial Instruments* as described below.

Changes in significant accounting policies

Revenue Recognition

Baytex adopted IFRS 15 *Revenue from Contracts with Customers* with a date of initial application of January 1, 2018. For the year ended December 31, 2017, $8.3 million of commodity purchases related to heavy oil sales have been reclassified from petroleum and natural gas sales to blending and other expense to conform with the requirements of IFRS 15. There were no adjustments made to the January 1, 2018 opening statement of financial position on adoption. The additional disclosures required by IFRS 15 are provided in note 11 to these consolidated financial statements.

The nature of the Company's performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal. Baytex recognizes revenue on a gross basis when it acts as the principal and has primary responsibility for the transaction. Revenue is recognized on a net basis if Baytex acts in the capacity of an agent rather than as a principal.

Revenue from the sale of heavy oil, light oil and condensate, natural gas liquids, and natural gas is recognized based on the consideration specified in contracts with customers. Baytex recognizes revenue when control of the product transfers to the customer and collection is reasonably assured. The amount of revenue recognized is based on the consideration specified in the contract. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon and collection is reasonably assured.

The transaction price for variable price contracts in the Canadian and U.S. operating segments is based on a representative commodity price index, and may be adjusted for quality, location, delivery method, or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantities of oil or natural gas transferred to customers. Market conditions, which impact the Company's ability to negotiate certain components of the transaction price, can also cause the amount of revenue recorded to fluctuate from period to period.

Tariffs, tolls and fees charged to other entities for use of pipelines and facilities owned by Baytex are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Financial Instruments

Baytex adopted IFRS 9 *Financial Instruments*, on January 1, 2018 using the retrospective method. The adoption of this standard did not result in a change in the recognition or measurement of any of the Company's financial instruments on transition.

IFRS 9 contains three principal classification categories for initial classification of financial assets: measured at amortized cost, fair value through other comprehensive income (“FVOCI”); or fair value through profit or loss (“FVTPL”). The previous IAS 39 categories of held to maturity, loans and receivables and available for sale are eliminated. Financial assets are categorized based on the Company’s objective for the asset and the subsequent cash flows. A financial asset is classified as amortized cost if the asset is held with the objective to collect contractual cash flows that are solely payments of principal and interest on principal amounts outstanding. A financial asset is classified as FVOCI if the asset is held with the objective to both collect contractual cash flows and sell the financial asset. All other financial assets are measured at FVTPL. Financial assets are assessed for impairment using an expected credit loss model. Trade and other receivables are classified and measured at amortized cost.

The initial classification of financial liabilities under IFRS 9 is fundamentally unchanged from the requirements under IAS 39. A financial liability is measured at amortized cost or FVTPL. A financial liability is measured at FVTPL if it is held-for-trading, a derivative, or designated as FVTPL at initial recognition. For liabilities measured at FVTPL, any change in value resulting from a change in Baytex’s credit risk is recorded through other comprehensive income or loss rather than net income or loss. Trade and other payables, bank loan and long-term notes are classified and measured as amortized cost.

Measurement Uncertainty and Judgments

Revenue - stand-alone selling price

Management is required to make estimates of the price at which the Company would sell the product separately to customers when allocating the transaction price realized in contracts using relative stand-alone selling prices. When making this estimate, management considers market prices and market conditions, as well as cash flows the Company intends to realize based on risk management policies, based on cost and margin objectives.

Future Accounting Pronouncements

Leases

In January 2016, the IASB issued IFRS 16 *Leases* which replaces IAS 17 *Leases.* IFRS 16 introduces a single recognition and measurement model for lessees, which will require recognition of lease assets and lease obligations on the balance sheet. Short-term leases and leases for low value assets are exempt from recognition and may be treated as operating leases and recognized through net income or loss. The standard is effective for annual periods beginning on or after January 1, 2019 with early adoption permitted if IFRS 15 has been adopted. The standard shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. The Company will adopt IFRS 16 on January 1, 2019. The Company has developed a plan to identify and review its various lease agreements in order to determine the impact that adoption of IFRS 16 will have on the consolidated financial statements. The Company is currently in the process of reviewing and analyzing the contracts that fall into the scope of the new standard.

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	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 147,122**	$ 122,063	**$ 200,483**	$ 155,473	**$ —**	$ —	**$ 347,605**	$ 277,536
Royalties	**(17,998)**	(14,119)	**(59,207)**	(45,895)	**—**	—	**(77,205)**	(60,014)
	129,124	107,944	**141,276**	109,578	**—**	—	**270,400**	217,522
Expenses								
Operating	**46,924**	45,981	**23,225**	24,944	**—**	—	**70,149**	70,925
Transportation	**7,836**	8,973	**—**	—	**—**	—	**7,836**	8,973
Blending and other	**18,239**	16,427	**—**	—	**—**	—	**18,239**	16,427
General and administrative	**—**	—	**—**	—	**10,563**	14,015	**10,563**	14,015
Exploration and evaluation	**1,358**	3,686	**—**	—	**—**	—	**1,358**	3,686
Depletion and depreciation	**47,602**	52,034	**64,262**	78,617	**—**	504	**111,864**	131,155
Share-based compensation	**—**	—	**—**	—	**3,915**	5,593	**3,915**	5,593
Financing and interest	**—**	—	**—**	—	**28,786**	29,293	**28,786**	29,293
Financial derivatives loss (gain)	**—**	—	**—**	—	**76,793**	(15,878)	**76,793**	(15,878)
Foreign exchange loss (gain)	**—**	—	**—**	—	**24,749**	(32,952)	**24,749**	(32,952)
(Gain) loss on disposition of oil and gas properties	**(244)**	524	**—**	—	**—**	—	**(244)**	524
Other (income) expense	**—**	—	**—**	—	**(288)**	493	**(288)**	493
	121,715	127,625	**87,487**	103,561	**144,518**	1,068	**353,720**	232,254
Net income (loss) before income taxes	**7,409**	(19,681)	**53,789**	6,017	**(144,518)**	(1,068)	**(83,320)**	(14,732)
Income tax expense (recovery)								
Current income tax expense (recovery)	**—**	—	**2**	(705)	**—**	—	**2**	(705)
Deferred income tax expense (recovery)	**1,776**	(6,146)	**4,434**	(11,042)	**(30,771)**	(6,107)	**(24,561)**	(23,295)
	1,776	(6,146)	**4,436**	(11,747)	**(30,771)**	(6,107)	**(24,559)**	(24,000)
Net income (loss)	**$ 5,633**	$ (13,535)	**$ 49,353**	$ 17,764	**$ (113,747)**	$ 5,039	**$ (58,761)**	$ 9,268
Total oil and natural gas capital expenditures[1]	**$ 30,587**	$ 23,665	**$ 48,222**	$ 59,568	**$ —**	$ —	**$ 78,809**	$ 83,233

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

	Canada		U.S.		Corporate		Consolidated	
Six Months Ended June 30	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 253,937**	$ 230,214	**$ 379,735**	$ 307,871	**$ —**	$ —	**$ 633,672**	$ 538,085
Royalties	**(29,332)**	(26,752)	**(112,712)**	(90,439)	**—**	—	**(142,044)**	(117,191)
	224,605	203,462	**267,023**	217,432	**—**	—	**491,628**	420,894
Expenses								
Operating	**92,344**	89,384	**43,693**	45,671	**—**	—	**136,037**	135,055
Transportation	**16,355**	17,015	**—**	—	**—**	—	**16,355**	17,015
Blending and other	**35,529**	26,484	**—**	—	**—**	—	**35,529**	26,484
General and administrative	**—**	—	**—**	—	**21,571**	26,598	**21,571**	26,598
Exploration and evaluation	**3,377**	5,008	**—**	—	**—**	—	**3,377**	5,008
Depletion and depreciation	**94,771**	101,865	**125,382**	149,970	**—**	1,651	**220,153**	253,486
Share-based compensation	**—**	—	**—**	—	**7,830**	10,142	**7,830**	10,142
Financing and interest	**—**	—	**—**	—	**56,796**	57,799	**56,796**	57,799
Financial derivatives loss (gain)	**—**	—	**—**	—	**104,343**	(51,766)	**104,343**	(51,766)
Foreign exchange loss (gain)	**—**	—	**—**	—	**60,966**	(43,540)	**60,966**	(43,540)
(Gain) loss on disposition of oil and gas properties	**(1,730)**	524	**—**	—	**—**	—	**(1,730)**	524
Other (income) expense	**—**	—	**—**	—	**(567)**	906	**(567)**	906
	240,646	240,280	**169,075**	195,641	**250,939**	1,790	**660,660**	437,711
Net income (loss) before income taxes	**(16,041)**	(36,818)	**97,948**	21,791	**(250,939)**	(1,790)	**(169,032)**	(16,817)
Income tax expense (recovery)								
Current income tax expense (recovery)	**—**	—	**(71)**	(1,441)	**—**	—	**(71)**	(1,441)
Deferred income tax expense (recovery)	**(4,331)**	(10,774)	**6,673**	(18,562)	**(49,820)**	(6,404)	**(47,478)**	(35,740)
	(4,331)	(10,774)	**6,602**	(20,003)	**(49,820)**	(6,404)	**(47,549)**	(37,181)
Net income (loss)	**$ (11,710)**	$ (26,044)	**$ 91,346**	$ 41,794	**$ (201,119)**	$ 4,614	**$ (121,483)**	$ 20,364
Total oil and natural gas capital expenditures(1)	**$ 80,086**	$ 128,151	**$ 90,231**	$ 117,645	**$ —**	$ —	**$ 170,317**	$ 245,796

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

As at	**June 30, 2018**	December 31, 2017
Canadian assets	**$ 1,683,451**	$ 1,677,821
U.S. assets	**2,784,814**	2,684,816
Corporate assets	**8,641**	9,474
Total consolidated assets	**$ 4,476,906**	$ 4,372,111

5. EXPLORATION AND EVALUATION ASSETS

	June 30, 2018	December 31, 2017
Balance, beginning of period	**$ 272,974**	$ 308,462
Capital expenditures	**1,402**	7,118
Divestitures	**(899)**	(1,276)
Exploration and evaluation expense	**(3,377)**	(8,253)
Transfer to oil and gas properties	**(5,923)**	(20,198)
Foreign currency translation	**7,991**	(12,879)
Balance, end of period	**$ 272,168**	$ 272,974

6. OIL AND GAS PROPERTIES

	Cost	Accumulated depletion	Net book value
Balance, December 31, 2016	**$ 7,764,037**	**$ (3,611,868)**	**$ 4,152,169**
Capital expenditures	319,148	—	319,148
Property acquisitions	136,007	—	136,007
Transferred from exploration and evaluation assets	20,198	—	20,198
Transferred from other assets	5,124	—	5,124
Change in asset retirement obligations	42,808	—	42,808
Divestitures	(105,272)	49,291	(55,981)
Foreign currency translation	(249,723)	68,641	(181,082)
Depletion	—	(480,082)	(480,082)
Balance, December 31, 2017	**$ 7,932,327**	**$ (3,974,018)**	**$ 3,958,309**
Capital expenditures	170,962	—	170,962
Property acquisitions	202	—	202
Transferred from exploration and evaluation assets	5,923	—	5,923
Change in asset retirement obligations	5,270	—	5,270
Divestitures	(15)	—	(15)
Foreign currency translation	178,598	(56,982)	121,616
Depletion	—	(218,813)	(218,813)
Balance, June 30, 2018	**$ 8,293,267**	**$ (4,249,813)**	**$ 4,043,454**

At the end of each reporting period, the Company performs an assessment to determine whether there is any indication of impairment or reversal of previously recorded impairments for the cash generating units ("CGU") that comprise oil and gas properties. The assessment of indicators is subjective in nature and requires Management to make judgments based on the information available at the reporting date. The Company determined that there were no indicators of impairment or impairment reversals for any of the Company's CGUs as at June 30, 2018.

7. BANK LOAN

	June 30, 2018	December 31, 2017
Bank loan - U.S. dollar denominated(1)	**$ 210,128**	$ 167,159
Bank loan - Canadian dollar denominated	**3,410**	46,217
Bank loan - principal	**213,538**	213,376
Unamortized debt issuance costs	**(1,151)**	(1,238)
Bank loan	**$ 212,387**	$ 212,138

(1) U.S. dollar denominated bank loan balance as at June 30, 2018 was US$159.9 million (US$133.5 million as at December 31, 2017).

On April 25, 2018, Baytex amended its credit facilities to extend maturity from June 4, 2019 to June 4, 2020. The amended revolving extendible secured credit facilities are comprised of a US$35 million operating loan (previously US$25 million) and a US$340 million syndicated loan for Baytex (previously US$350 million) and a US$200 million syndicated loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities").

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants, including the financial covenants detailed below, and do not require any mandatory principal payments prior to maturity on June 4, 2020. Baytex may request an extension of the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year period at any time). Advances (including letters of credit) under the Revolving 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 Revolving 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, 2018, Baytex had $15.2 million of outstanding letters of credit (December 31, 2017 - $14.6 million) under the Revolving Facilities.

At June 30, 2018, Baytex was in compliance with all of the covenants contained in the Revolving Facilities. The following table summarizes the financial covenants applicable to the Revolving Facilities and Baytex's compliance therewith as at June 30, 2018.

Covenant Description	Position as at June 30, 2018	Ratio for the quarter ended June 30, 2018 and thereafter
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	**0.57:1.00**	**3.50:1.00**
Interest Coverage[3] (Minimum Ratio)	**4.05:1.00**	**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, 2018, the Company's Senior Secured Debt totaled $228.7 million.

(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, 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. Bank EBITDA for the twelve months ended June 30, 2018 was $402.7 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, 2018 were $99.4 million.

8. LONG-TERM NOTES

	June 30, 2018	December 31, 2017
6.75% notes (US$150,000 – principal) due February 17, 2021	**197,130**	187,770
5.125% notes (US$400,000 – principal) due June 1, 2021	**525,680**	500,720
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	**300,000**	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	**525,680**	500,720
Total long-term notes - principal	**1,548,490**	1,489,210
Unamortized debt issuance costs	**(14,181)**	(15,026)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,534,309**	$ 1,474,184

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 Revolving 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 2.0:1. As at June 30, 2018, the fixed charge coverage ratio was 4.05:1.00.

9. ASSET RETIREMENT OBLIGATIONS

	June 30, 2018	December 31, 2017
Balance, beginning of period	**$ 368,995**	$ 331,517
Liabilities incurred	**2,207**	5,825
Liabilities settled	**(6,187)**	(13,471)
Liabilities acquired	**132**	22,264
Liabilities divested	**(527)**	(19,940)
Accretion (note 15)	**4,630**	8,682
Change in estimate	**3,063**	(24,028)
Changes in discount rates and inflation rates	**—**	61,011
Foreign currency translation	**1,550**	(2,865)
Balance, end of period	**$ 373,863**	$ 368,995

10. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10,000,000 preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at June 30, 2018, 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, 2016	**233,449**	**$**	**4,422,661**
Transfer from contributed surplus on vesting and conversion of share awards	2,002		20,915
Balance, December 31, 2017	**235,451**	**$**	**4,443,576**
Transfer from contributed surplus on vesting and conversion of share awards	1,211		8,725
Balance, June 30, 2018	**236,662**	**$**	**4,452,301**

11. PETROLEUM AND NATURAL GAS SALES

Petroleum and natural gas sales primarily consists of revenues earned from the sale of produced oil and natural gas volumes pursuant to fixed or variable price contracts, including the physical delivery contracts for fixed volumes outlined in note 17. The activities that generate petroleum and natural gas sales for the Canadian and U.S. operating segments are described below.

Canada Segment

Petroleum and natural gas sales for Baytex's Canadian operating segment primarily consists of revenues generated from the Company's interest in operated oil and natural gas properties and production taken in-kind related to its interest in non-operated oil and natural gas properties. The Company enters contracts with customers for the sale of production volumes with terms ranging from a period of one month to two years.

Under its contracts with customers, Baytex is required to deliver volumes of heavy oil, light oil and condensate, natural gas liquids and natural gas to agreed upon locations where control over the delivered volumes is transferred to the customer. Revenue is recognized when control of each unit of product is transferred to the customer with revenues due on the 25th day of the month following delivery.

Baytex's customers are primarily oil and natural gas marketers and partners in joint operations in the oil and natural gas industry. Concentration of credit risk is mitigated by marketing production to several oil and natural gas marketers under customary industry and payment terms. Baytex reviews the credit worthiness and obtains certain financial assurances from customers prior to entering sales contracts. The financial strength of the Company's customers is reviewed on a routine basis.

U.S. Segment

Petroleum and natural gas sales for Baytex's U.S. operating segment primarily consists of revenues generated from the Company's interest in non-operated oil and natural gas properties where the Company has not elected its right to take its production in-kind. The operator of the oil and natural gas properties that comprise the U.S. operating segment enters contracts with customers, conducts the activities required to transfer control of light oil and condensate, natural gas liquids and natural gas volumes to the customer, and collects and remits payments from the customer to Baytex.

The Company's petroleum and natural gas sales from contracts with customers for each reportable segment is set forth in the following table.

	Three Months Ended June 30					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Heavy oil	**$ 133,768**	**$ —**	**$ 133,768**	$ 103,996	$ —	$ 103,996
Light oil and condensate	**5,484**	**161,078**	**166,562**	6,189	117,335	123,524
NGL	**4,092**	**22,794**	**26,886**	2,472	17,555	20,027
Natural gas sales	**3,778**	**16,611**	**20,389**	9,406	20,583	29,989
Total petroleum and natural gas sales	**$ 147,122**	**$ 200,483**	**$ 347,605**	$ 122,063	$ 155,473	$ 277,536

	Six Months Ended June 30					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Heavy oil	**$ 225,651**	**$ —**	**$ 225,651**	$ 193,747	$ —	$ 193,747
Light oil and condensate	**10,336**	**305,684**	**316,020**	12,726	233,869	246,595
NGL	**7,448**	**40,972**	**48,420**	5,444	34,279	39,723
Natural gas sales	**10,502**	**33,079**	**43,581**	18,297	39,723	58,020
Total petroleum and natural gas sales	**253,937**	**379,735**	**633,672**	230,214	307,871	538,085

Included in accounts receivable at June 30, 2018 is $119.3 million (December 31, 2017 - $91.6 million) of accrued production revenue related to deliveries for periods ended prior to the reporting date.

12. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to the share awards of $3.9 million and $7.8 million for the three and six months ended June 30, 2018, respectively ($5.6 million and $10.1 million for the three and six months ended June 30, 2017, respectively).

The weighted average fair value of share awards granted was $4.17 per restricted and performance award for the six months ended June 30, 2018 and $5.77 per restricted and performance award for the six months ended June 30, 2017.

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, 2016	**1,508**	**1,737**	**3,245**
Granted	1,636	1,584	3,220
Vested and converted to common shares	(959)	(1,043)	(2,002)
Forfeited	(157)	(25)	(182)
Balance, December 31, 2017	**2,028**	**2,253**	**4,281**
Granted	1,944	1,854	3,798
Vested and converted to common shares	(590)	(621)	(1,211)
Forfeited	(125)	(96)	(221)
Balance, June 30, 2018	**3,257**	**3,390**	**6,647**

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

13. NET INCOME (LOSS) PER SHARE

Baytex calculates basic income per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income per share amounts reflect the potential dilution that could occur if share awards were converted. The treasury stock method is used to determine the dilutive effect of share awards whereby the potential conversion of share awards 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					
	2018			2017		
	Net loss	**Weighted average common shares (000s)**	**Net loss per share**	Net income	Weighted average common shares (000s)	Net income per share
Net income (loss) - basic	**$ (58,761)**	**236,628**	**$ (0.25)**	$ 9,268	234,204	$ 0.04
Dilutive effect of share awards	**—**	**—**	**—**	—	2,411	—
Net income (loss) - diluted	**$ (58,761)**	**236,628**	**$ (0.25)**	$ 9,268	236,615	$ 0.04

	Six Months Ended June 30					
	2018			2017		
	Net loss	**Weighted average common shares (000s)**	**Net loss per share**	Net income	Weighted average common shares (000s)	Net income per share
Net income (loss) - basic	**$ (121,483)**	**236,472**	**$ (0.51)**	$ 20,364	234,112	$ 0.09
Dilutive effect of share awards	**—**	**—**	**—**	—	2,603	—
Net income (loss) - diluted	**$ (121,483)**	**236,472**	**$ (0.51)**	$ 20,364	236,715	$ 0.09

For the three months ended June 30, 2018 and 2017, the effect of 6.6 million share awards and 1.6 million share awards, respectively, were excluded from the calculation of diluted earnings per share as they were determined to be anti-dilutive. For the six months ended June 30, 2018 and 2017, the effect of 6.6 million share awards and 1.1 million share awards, respectively, were excluded from the calculation of diluted earnings per share as they were determined to be anti-dilutive.

14. INCOME TAXES

The provision for income taxes has been computed as follows:

	Six Months Ended June 30	
	2018	2017
Net loss before income taxes	**$ (169,032)**	$ (16,817)
Expected income taxes at the statutory rate of 27.00% (2017 – 26.93%)(1)	**(45,639)**	(4,529)
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	**2,024**	2,732
Non-taxable portion of foreign exchange loss (gain)	**8,003**	(5,668)
Effect of rate adjustments for foreign jurisdictions	**(19,012)**	(23,301)
Effect of change in deferred tax benefit not recognized(2)	**8,003**	(5,668)
Adjustments and assessments	**(928)**	(747)
Income tax recovery	**$ (47,549)**	$ (37,181)

(1) Expected income tax rate increased due to an increase in the corporate income tax rate in Saskatchewan from 11.75% to 12.00%, effective January 1, 2018.

(2) A deferred income tax asset has not been recognized for allowable capital losses of $116 million related to the unrealized foreign exchange losses arising from the translation of U.S. dollar denominated long-term notes ($86 million as at December 31, 2017).

As disclosed in the 2017 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. Subsequent to June 30, 2018, an Appeals Officer was assigned to its file. Baytex remains confident that its original tax filings are correct and intends to defend those tax filings through the appeals process.

15. FINANCING AND INTEREST

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Interest on bank loan	**$ 3,260**	$ 3,035	**$ 6,189**	$ 5,588
Interest on long-term notes	**22,270**	22,880	**43,852**	45,519
Non-cash financing	**934**	1,150	**2,125**	2,280
Accretion on asset retirement obligations (note 9)	**2,322**	2,228	**4,630**	4,412
Financing and interest	**$ 28,786**	$ 29,293	**$ 56,796**	$ 57,799

16. FOREIGN EXCHANGE

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	**2018**	2017
Unrealized foreign exchange loss (gain)	**$ 22,673**	$ (32,045)	**$ 58,719**	$ (43,383)
Realized foreign exchange loss (gain)	**2,076**	(907)	**2,247**	(157)
Foreign exchange loss (gain)	**$ 24,749**	$ (32,952)	**$ 60,966**	$ (43,540)

17. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, bank loan and long-term notes.

Categories of Financial Instruments

The estimated fair values of the financial instruments have been determined based on the Company's assessment of available market information. To estimate fair values of its financial instruments, Baytex uses quoted market prices when available, or third-party models and valuation methodologies that use observable market data. Baytex aims to maximize the use of observable inputs, where practical. The fair values of financial instruments, other than financial derivatives, bank loan and long-term notes, are equal to their carrying amounts due to the short-term maturity of these instruments. The fair value of financial derivatives are based on mark-to-market values of the underlying financial derivative contracts. The fair value of the bank loan is based on the principal amount of borrowings outstanding. The fair value of the long-term notes are based on the trading value of the notes.

Fair Value of Financial Instruments

Baytex classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.

- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.

- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

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, 2018		December 31, 2017		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL(1)					
Financial derivatives	**$ 10,388**	**$ 10,388**	$ 18,510	$ 18,510	Level 2
Total	**$ 10,388**	**$ 10,388**	$ 18,510	$ 18,510	
Assets at amortized cost					
Trade and other receivables	**$ 142,255**	**$ 142,255**	$ 112,844	$ 112,844	—
Total	**$ 142,255**	**$ 142,255**	$ 112,844	$ 112,844	
Financial Liabilities					
FVTPL(1)					
Financial derivatives	**$ (107,067)**	**$ (107,067)**	$ (50,095)	$ (50,095)	Level 2
Total	**$ (107,067)**	**$ (107,067)**	$ (50,095)	$ (50,095)	
Financial liabilities at amortized cost					
Trade and other payables	**$ (165,062)**	**$ (165,062)**	$ (144,542)	$ (144,542)	—
Bank loan	**(212,387)**	**(213,538)**	(212,138)	(213,376)	—
Long-term notes	**(1,534,309)**	**(1,494,756)**	(1,474,184)	(1,430,902)	Level 1
Total	**$ (1,911,758)**	**$ (1,873,356)**	$ (1,830,864)	$ (1,788,820)	

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

There were no transfers between Level 1 and Level 2 in 2017 or during the six months ended June 30, 2018.

Foreign Currency Risk

The carrying amount of the Company’s U.S. dollar denominated monetary assets and liabilities at the reporting date are as follows:

	Assets		Liabilities	
	June 30, 2018	December 31, 2017	**June 30, 2018**	December 31, 2017
U.S. dollar denominated	**US$52,305**	US$51,665	**US$1,251,618**	US$1,294,615

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of July 30, 2018:

	Period	Volume	Price/Unit(1)	Index		Fair Value(2) *($ millions)*
Oil						
Basis swap	Jul 2018 to Dec 2018	6,000 bbl/d	WTI less US$14.24/bbl	WCS	$	11.2
3-way option (3)	Jul 2018 to Dec 2018	2,000 bbl/d	US$60.00/US$54.40/US$40.00	WTI	$	(5.3)
Fixed - Sell	Jul 2018 to Dec 2018	14,000 bbl/d	US$52.31/bbl	WTI	$	(62.8)
Fixed - Sell	Jul 2018 to Dec 2018	4,000 bbl/d	US$61.31/bbl	Brent	$	(17.1)
Fixed - Sell	Jan 2019 to Jun 2019	2,000 bbl/d	US$62.85/bbl	WTI	$	(1.8)
Fixed - Sell	Jan 2019 to Dec 2019	2,000 bbl/d	US$61.70/bbl	WTI	$	(3.4)
Swaption (4)	Jan 2019 to Dec 2019	2,000 bbl/d	US$61.70/bbl	WTI	$	(6.1)
Swaption (4)	Jan 2019 to Dec 2019	2,000 bbl/d	US$59.60/bbl	WTI	$	(7.5)
3-way option (3)	Jan 2019 to Dec 2019	2,000 bbl/d	US$70.00/US$60.00/US$50.00	WTI	$	(1.6)
3-way option (3)	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.50/US$65.50/US$55.50	Brent	$	(2.1)
3-way option (3)	Jan 2019 to Dec 2019	1,000 bbl/d	US$77.55/US$70.00/US$60.00	Brent	$	(1.3)
3-way option (3)	Jan 2019 to Dec 2019	1,000 bbl/d	US$83.00/US$73.00/US$63.00	Brent	$	(0.1)
Natural Gas						
Fixed - Sell	Jul 2018 to Dec 2018	15,000 mmbtu/d	US$3.01	NYMEX	$	0.3
Fixed - Sell	Jul 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO	$	0.9
Total					**$**	**(96.7)**
Current asset						10.4
Current liability						101.0
Non-current liability						6.1

(1) Based on the weighted average price per unit for the period.
(2) Fair values as at June 30, 2018. For the purposes of the table, contracts entered subsequent to June 30, 2018 will have no fair value assigned.
(3) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$60/US$54.40/US$40 contract, Baytex receives WTI plus US$14.40/bbl when WTI is at or below US$40/bbl; Baytex receives US$54.40/bbl when WTI is between US$40/bbl and US$54.40/bbl; Baytex receives the market price when WTI is between US$54.40/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US$60/bbl.
(4) For these contracts, the counterparty has the right, if exercised on December 31, 2018, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

Financial derivatives are marked-to-market at the end of each reporting period, with the following reflected in the consolidated statements of income or loss:

	Three Months Ended June 30				Six Months Ended June 30			
		2018		2017		**2018**		2017
Realized financial derivatives loss (gain)	**$**	**29,408**	$	(2,649)	**$**	**39,249**	$	(2,923)
Unrealized financial derivatives loss (gain)		**47,385**		(13,229)		**65,094**		(48,843)
Financial derivatives loss (gain)	**$**	**76,793**	$	(15,878)	**$**	**104,343**	$	(51,766)

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 30, 2018, Baytex had committed to deliver the following volumes of raw bitumen to market on rail:

Period	Volume
Jul 2018 to Dec 2018	8,000 bbl/d
Sep 2018 to Dec 2019 (1)	2,500 bbl/d
Jan 2019 to Dec 2020 (1)	5,000 bbl/d

(1) Contract entered subsequent to June 30, 2018.

18. SUBSEQUENT EVENT

On June 18, 2018, Baytex and Raging River Exploration Inc. ("Raging River") announced that their respective boards of directors unanimously agreed to a strategic combination of the two companies (the "Transaction"). The companies entered into an agreement (the "Arrangement Agreement") to effect the Transaction by way of a plan of arrangement under the *Business Corporations Act* (Alberta). Under the Transaction, Baytex will issue 1.36 common shares for each common share of Raging River.

The business combination is subject to approval by the shareholders of both companies, the Court of Queen's Bench of Alberta and certain regulatory and other authorities, and is subject to the satisfaction or waiver of other customary closing conditions. A joint information circular containing information relevant to the Transaction was filed on July 20, 2018. Each company will hold a special meeting of shareholders on August 21, 2018. The shareholders of Raging River will be asked to approve the plan of arrangement. The shareholders of Baytex will be asked to approve the issuance of common shares of Baytex pursuant to the plan of arrangement. The Transaction is anticipated to close on August 22, 2018. The Arrangement Agreement provides for a mutual non-completion fee of $50 million in the event the Transaction is not completed or is terminated by either party in certain circumstances.

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

Raymond T. Chan
Chairman of the Board
Baytex Energy Corp.

Mark R. Bly[(3)(4)]
Independent Businessman

James L. Bowzer[(3)]
Independent Businessman

Edward Chwyl[(2)(3)]
Independent Businessman

Trudy M. Curran[(1)(2)(4)]
Independent Businesswoman

Naveen Dargan[(1)(2)]
Independent Businessman

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

Gregory K. Melchin[(1)(4)]
Independent Businessman

Mary Ellen Peters[(1)(2)]
Independent Businesswoman

Dale O. Shwed[(3)]
President & Chief Executive Officer
Crew Energy Inc.

(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
Alberta Treasury Branches
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
Chief Financial Officer

Richard P. Ramsay
Chief Operating Officer

Geoffrey J. Darcy
Senior Vice President, Marketing

Brian G. Ector
Senior Vice President, Capital Markets and Public Affairs

Kendall D. Arthur
Vice President, Lloydminster, Conventional and U.S. Business Units

Murray J. Desrosiers
Vice President, General Counsel and Corporate Secretary

Ryan M. Johnson
Vice President, Peace River Business Unit

Chad L. Kalmakoff
Vice President, Finance

M. Scott Lovett
Vice President, Business Development

Gregory A. Sawchenko
Vice President, Land

AUDITORS

KPMG LLP

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

Sproule Unconventional Limited
Ryder Scott Company L.P.

TRANSFER AGENT

Computershare Trust Company of Canada

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE