BAYTEX ENERGY CORP.

Q3 REPORT / 2018

PRESS RELEASE

CALGARY, ALBERTA (November 2, 2018) - Baytex Energy Corp. ("Baytex")(TSX, NYSE: BTE) reports its operating and financial results for the three and nine months ended September 30, 2018 (all amounts are in Canadian dollars unless otherwise noted).

“Our strategic combination has repositioned Baytex as a North American crude oil producer with strong free cash flow and an improved balance sheet. We have completed the integration while delivering excellent drilling results, particularly the oil flow rates from our two new wells in the Pembina region of our Duvernay light oil play. We are also benefiting from strong oil price diversification, which includes light oil production in the Eagle Ford and high netback Viking light oil production in Canada. As we plan for 2019, our top priority will be disciplined capital allocation to drive meaningful free cash flow,” commented Ed LaFehr, President and Chief Executive Officer.

Highlights

- Completed the strategic combination with Raging River Exploration Inc. (“Raging River”) on August 22, 2018, creating a well-capitalized, light oil company with an attractive free cash flow profile and improved balance sheet. Our light oil assets generate approximately 80% of our operating netback.
- Generated adjusted funds flow of $171 million ($0.46 per basic share), $32 million in excess of exploration and development capital expenditures of $139 million, which delivered production of 82,412 boe/d (81% oil and NGL) during Q3/2018. Our results reflect a 40 day contribution from the Raging River assets.
- Completed two (2.0 net) significant light oil discovery wells in the Pembina area of the East Duvernay Shale. These two wells established an average 30-day initial production rate of approximately 750 boe/d per well (88% oil and NGLs), further proving the oil window in the Pembina area where we control 256 prospective sections of 100% interest land.
- Produced approximately 97,000 boe/d (84% crude oil and NGL) during the month of October, demonstrating continued strong operating results across our portfolio of oil assets and the successful integration of Raging River.
- Reduced annual guidance for operating expenses by 4% (at mid-point) to $10.50-$10.75/boe, reflecting strong performance year-to-date of $10.54/boe. Continued to drive efficiency across our business with a 5% reduction in forecast 2018 general and administrative expenses to $1.55/boe.
- Implemented plans to optimize our heavy oil production in the face of volatile heavy oil prices. Our optimization strategy will reduce our Q4/2018 heavy oil volumes by approximately 5,000 boe/d (90% oil), which represents 5% of our total production, and given current pricing, will have a minimal impact on our adjusted funds flow.
- Secured additional rail capacity, which increases our crude oil volumes delivered to market by rail to 11,000 bbl/d (approximately 40% of our heavy oil production) through 2019. Commencing January 1, 2019, approximately 70% of our crude by rail commitments are WTI based contracts with no WCS pricing exposure.
- Based on preliminary 2019 plans, we expect to generate approximately $900 million of adjusted funds flow, 80% of which is derived from our light oil assets in the Eagle Ford and Viking. With an updated capital program of $700 million (at the mid-point), we expect to generate $200 million of cash flow above capital expenditures.

	Three Months Ended			Nine Months Ended	
	September 30, 2018	June 30, 2018	September 30, 2017	**September 30, 2018**	September 30, 2017
FINANCIAL *(thousands of Canadian dollars, except per common share amounts)*					
Petroleum and natural gas sales	**$ 436,761**	$ 347,605	$ 258,620	**$ 1,070,433**	$ 796,706
Adjusted funds flow (1)	**171,210**	106,690	77,340	**362,155**	241,845
Per share – basic	**0.46**	0.45	0.33	**1.28**	1.03
Per share – diluted	**0.45**	0.45	0.33	**1.28**	1.02
Net income (loss)	**27,412**	(58,761)	(9,228)	**(94,071)**	11,136
Per share – basic	**0.07**	(0.25)	(0.04)	**(0.33)**	0.05
Per share – diluted	**0.07**	(0.25)	(0.04)	**(0.33)**	0.05
Shares Outstanding – basic (thousands)					
Weighted average	**375,435**	236,628	235,451	**283,302**	234,563
End of period	**553,950**	236,662	235,451	**553,950**	235,451

		Three Months Ended			Nine Months Ended	
		September 30, 2018	June 30, 2018	September 30, 2017	**September 30, 2018**	September 30, 2017
FINANCIAL (thousands of Canadian dollars)						
Exploration and development	**$**	**139,195**	$ 78,830	$ 61,544	**$ 311,559**	$ 236,110
Acquisitions, net of divestitures		**46**	(21)	(7,436)	**(2,001)**	63,794
Total oil and natural gas capital expenditures	**$**	**139,241**	$ 78,809	$ 54,108	**$ 309,558**	$ 299,904
Bank loan [2]	**$**	**490,565**	$ 213,538	$ 226,249	**$ 490,565**	$ 226,249
Long-term notes [2]		**1,527,733**	1,548,490	1,488,450	**1,527,733**	1,488,450
Long-term debt		**2,018,298**	1,762,028	1,714,699	**2,018,298**	1,714,699
Working capital (surplus) deficiency		**93,792**	22,807	34,106	**93,792**	34,106
Net debt [3]	**$**	**2,112,090**	$ 1,784,835	$ 1,748,805	**$ 2,112,090**	$ 1,748,805
OPERATING						
Daily Production						
Light oil and condensate (bbl/d)		**29,731**	21,100	20,041	**23,965**	21,343
Heavy oil (bbl/d)		**27,036**	25,544	26,161	**25,824**	25,454
NGL (bbl/d)		**10,076**	9,419	8,940	**9,549**	8,982
Total liquids (bbl/d)		**66,843**	56,063	55,142	**59,338**	55,779
Natural gas (mcf/d)		**93,414**	87,605	85,006	**89,449**	88,166
Oil equivalent (boe/d @ 6:1) [4]		**82,412**	70,664	69,310	**74,246**	70,473
Netback (thousands of Canadian dollars)						
Total sales, net of blending and other expense	**$**	**417,213**	$ 329,366	$ 242,551	**$ 1,015,356**	$ 754,152
Royalties		**(91,945)**	(77,205)	(55,176)	**(233,989)**	(172,367)
Operating expense		**(77,698)**	(70,149)	(64,391)	**(213,735)**	(199,446)
Transportation expense		**(9,520)**	(7,836)	(9,312)	**(25,875)**	(26,327)
Operating netback	**$**	**238,050**	$ 174,176	$ 113,672	**$ 541,757**	$ 356,012
General and administrative		**(10,158)**	(10,563)	(11,074)	**(31,729)**	(37,672)
Cash financing and interest		**(26,343)**	(25,530)	(24,526)	**(76,384)**	(75,632)
Realized financial derivatives (loss) gain		**(30,854)**	(29,408)	2,795	**(70,103)**	5,719
Other [5]		**515**	(1,985)	(3,527)	**(1,386)**	(6,582)
Adjusted funds flow	**$**	**171,210**	$ 106,690	$ 77,340	**$ 362,155**	$ 241,845
Netback (per boe)						
Total sales, net of blending and other expense	**$**	**55.03**	$ 51.22	$ 38.04	**$ 50.09**	$ 39.20
Royalties		**(12.13)**	(12.01)	(8.65)	**(11.54)**	(8.96)
Operating expense		**(10.25)**	(10.91)	(10.10)	**(10.54)**	(10.37)
Transportation expense		**(1.26)**	(1.22)	(1.46)	**(1.28)**	(1.37)
Operating netback	**$**	**31.39**	$ 27.08	$ 17.83	**$ 26.73**	$ 18.50
General and administrative		**(1.34)**	(1.64)	(1.74)	**(1.57)**	(1.96)
Cash financing and interest		**(3.47)**	(3.97)	(3.85)	**(3.77)**	(3.93)
Realized financial derivatives (loss) gain		**(4.07)**	(4.57)	0.44	**(3.46)**	0.30
Other [5]		**0.07**	(0.31)	(0.55)	**(0.06)**	(0.34)
Adjusted funds flow	**$**	**22.58**	$ 16.59	$ 12.13	**$ 17.87**	$ 12.57

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, asset retirement obligations settled and transaction costs. 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. In addition, we have removed transaction costs from the Raging River combination as we consider these costs non-recurring and not reflective of our ongoing ability to generate 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 nine months ended September 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) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and payments on onerous contracts. Refer to the Q3/2018 MD&A for further information on these amounts.

Strategic Combination with Raging River

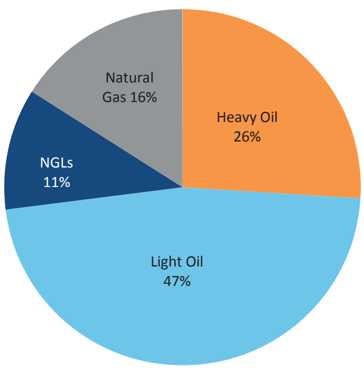
On August 22, 2018, we completed the strategic combination with Raging River. The transaction resulted in holders of common shares of Raging River receiving 1.36 common shares of Baytex for each Raging River Share owned. Our third quarter results include 40 days of operations from the Raging River assets representing the August 22 to September 30 period. During this period, production from the Raging River assets averaged 23,750 boe/d (Q3/2018 impact of 10,327 boe/d), consistent with our expectations.

Since closing the transaction, we have successfully integrated the two companies, undertaken a detailed strategic review of our operations, confirmed the organic growth opportunities in our diversified portfolio of assets and delivered on our near-term targets. Our strategic combination with Raging River has repositioned Baytex as a self-funding North American producer focused on per share value creation with a target of providing investors with a 10% to 15% total annual return.

In October, we produced approximately 97,000 boe/d (84% crude oil and NGL) from our high quality oil assets, including the Eagle Ford in Texas and the Viking, Peace River, Lloydminster and East Duvernay Shale properties in Canada. We 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.

One of the key benefits of the combination with Raging River is our strong oil price diversification, which includes light oil and condensate production in the Eagle Ford which commands premium Louisiana Light Sweet ("LLS") based pricing and our high netback Viking light oil production in Canada. At current prices, approximately 80% of our operating netback is derived from these two assets. The following charts summarize our exposure by commodity based on production, revenue and proved reserves.

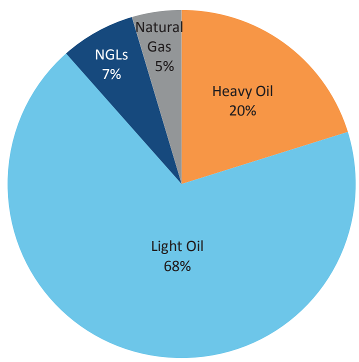
Production



Production composition based on 2019 preliminary guidance of 95,000-100,000 boe/d.

For 2019, 11,000 bbl/d (approximately 40%) of heavy oil production is forecast to be delivered to market by rail, of which 70% of our crude by rail commitments are WTI based contracts with no WCS pricing exposure.

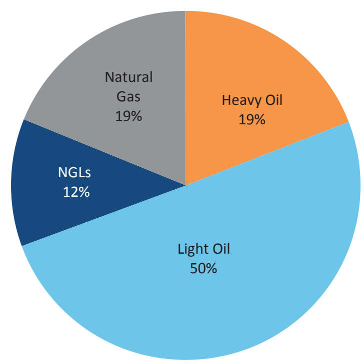
Revenue



Revenue composition excludes financial derivatives gains (losses) and is based on 2019 preliminary production guidance and forward strip pricing assumptions. Revenue totals approximately $1.9 billion.

Pricing assumptions: WTI - US$70/bbl, LLS - US$75/bbl, WCS differential - US$30/bbl, MSW differential - US$15/bbl, NYMEX gas - US$2.90/mcf, FX rate (C$/US$) - 1.30.

Proved Reserves



Proved reserves breakdown based on Baytex gross reserves as at December 31, 2017 as evaluated by Sproule Unconventional Limited and Ryder Scott Company L.P., and Raging River gross reserves as at December 31, 2017 as evaluated by Sproule Associates Limited and GLJ Petroleum Consultants Ltd. Light oil includes condensate in the Eagle Ford.

Proved reserves total 338 mmboe as at December 31, 2017.

Operating Results

We continued to deliver on our operational and financial targets during the third quarter. We successfully integrated the Raging River assets and executed our drilling program with strong results realized in the Eagle Ford and Canada.

Production average 82,412 boe/d (81% oil and NGL) in Q3/2018, as compared to 70,664 boe/d (79% oil and NGL) in Q2/2018. Production in the first nine months of 2018 averaged 74,246 boe/d. Production from the legacy Baytex assets (excluding Raging River) averaged 72,085 boe/d in Q3/2018.

During the third quarter, exploration and development capital expenditures totaled $139 million, bringing the aggregate spending in the first nine months of 2018 to $312 million. We participated in the drilling of 116 (74.8 net) wells with a 98% success rate during the third quarter.

Eagle Ford and Viking Light Oil

Our Eagle Ford asset in South Texas is one of the premier oil resource plays in North America. The asset generates a strong operating netback and free cash flow and contains a significant inventory of development prospects. In Q3/2018, we allocated 32% of our exploration and development expenditures to this asset generating production of 37,198 boe/d (77% oil and NGL), as compared to 36,622 boe/d in Q2/2018. During the third quarter, the Eagle Ford generated operating netback of $130 million and free cash flow (after capital expenditures) of $85 million.

We continue to see strong well performance driven by enhanced completions in the Eagle Ford. In Q3/2018, we participated in the drilling of 29 (8.0 net) wells and commenced production from 26 (4.9 net) wells. The wells that have been on production for more than 30 days in the quarter established 30-day initial production rates of approximately 1,600 boe/d (54% light oil and condensate). These wells were completed with approximately 28 effective frac stages per well and proppant per completed foot of approximately 1,800 pounds.

Our Viking asset is a shallow, light oil resource play (approximately 36° API) in western Canada with 460 net sections of prospective lands. For the period August 22 to September 30, production from the Viking averaged 22,158 boe/d (excluding heavy oil) and we drilled 42 (30.5 net) wells. The extended reach horizontal results continue to exceed expectations with multiple, previously untested sections being proven highly economic. We currently have five drilling rigs and 1.5 frac crews executing our development program.

Heavy Oil

Our heavy oil assets at Peace River and Lloydminster produced a combined 27,036 bbl/d during the third quarter, as compared to 25,544 bbl/d in Q2/2018. The higher volumes reflect the continued success of our development program and the addition of heavy oil assets acquired as part of the Raging River combination (964 bbl/d for the period August 22 to September 30).

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. In Q3/2018, we drilled five (5.0 net) wells and commenced production from four (4.0 net) wells. In the northern Seal area of Peace River, our first six wells have established 30-day initial production rates of approximately 700 boe/d per well.

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 drilled 36 (27.3 net) oil wells during the third quarter. In addition, we successfully completed the expansion of our Kerrobert thermal project with productive capability increasing to approximately 2,000 bbl/d during the fourth quarter.

East Duvernay Shale Light Oil – Significant Pembina Light Oil Discovery

We continue to prudently advance the evaluation of this emerging light oil play in central Alberta. The East Duvernay Shale is an early stage, high netback light oil resource play where we have amassed over 430 sections of land. The early focus has been to delineate and evaluate the potential depth of this light oil resource.

Our development has taken an important step forward with two new light oil discovery wells in the Pembina area located approximately 5 and 7 miles south of our initial 14-36 discovery well. These two wells established an average 30-day initial production rate of approximately 750 boe/d per well (88% oil and NGLs). We are also following up the initial 14-36 discovery with two additional wells from the original surface pad. Drilling operations are complete and we anticipate initiating completion activities in early November.

The two recent discovery wells demonstrate continuity of the oil window and provide a focus for 2019 pad development drilling in addition to incremental delineation drilling to continue to evaluate the commerciality of our lands. We control 256 sections of 100% interest land in the Pembina area.

During the third quarter, we also completed one (1.0 net) well at Ferrybank that is currently shut-in for re-licensing due to encountering H_2S in the early phase of flow back and one (1.0 net) well at Gilby, which is currently on production at 80 boe/d (77% oil and NGL).

Financial Review

We generated adjusted funds flow of $171 million ($0.46 per basic share) in Q3/2018, compared to $107 million ($0.45 per basic share) in Q2/2018 and $77 million ($0.33 per basic share) in Q3/2017. Excluding financial derivatives losses, adjusted funds flow in Q3/2018 was $202 million, compared to $136 million in Q2/2018. The increase in adjusted funds flow is largely attributable to an initial contribution from the high netback Raging River production.

In the first nine months of 2018, we generated adjusted funds flow of $362 million ($432 million excluding realized financial derivatives losses), as compared to exploration and development capital expenditures of $312 million.

Financial Liquidity

Our net debt totaled $2.1 billion at September 30, 2018, which is up from $1.8 billion at June 30, 2018. The increase in net debt is due to the $364 million of net debt assumed in conjunction with the Raging River transaction. We maintain strong financial liquidity with our credit facilities approximately 50% undrawn and our first long-term note maturity not until 2021. We have established a new $300 million term loan facility that is due June 2020 and is secured by the assets of Raging River. This additional facility, combined with our existing facilities of US$575 million, increased our credit capacity to approximately $1.04 billion.

Operating Netback

Our operating netback (excluding realized financial derivatives gains and losses) improved 76% to $31.39/boe in Q3/2018, as compared to $17.83/boe in Q3/2017. During the third quarter, we benefited from strong liquids pricing in the Eagle Ford and an initial contribution from our high netback Viking light oil production. The Eagle Ford generated an operating netback of $38.03/boe during Q3/2018 while our Canadian operations generated an operating netback of $25.94/boe.

In Q3/2018, the price for West Texas Intermediate light oil ("WTI") averaged US$69.50/bbl, as compared to US$48.20/bbl in Q3/2017. The discount for Canadian heavy oil, as measured by the price differential between Western Canadian Select ("WCS") and WTI, averaged US$22.25/bbl in Q3/2018 as compared to US$9.94/bbl in Q3/2017.

In the Eagle Ford, our assets are proximal to Gulf Coast markets with light oil and condensate production priced off the LLS crude oil benchmark, which is a function of the Brent price. In Q3/2018, the price for LLS averaged US$75.25/bbl as compared to US$50.27/bbl in Q3/2017. During the third quarter, our light oil and condensate realized price in the Eagle Ford of US$71.41/bbl (or $93.37/bbl) represented a US$3.84/bbl discount to LLS.

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

	Three Months Ended September 30					
	2018			2017		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	**Canada**	**U.S.**	**Total**
Total production (boe/d)	**45,214**	**37,198**	**82,412**	34,560	34,750	69,310
Total sales, net of blending and other expense	**$ 47.66**	**$ 63.98**	**$ 55.03**	$ 33.41	$ 42.64	$ 38.04
Less:						
Royalties	**6.28**	**19.23**	**12.13**	4.71	12.58	8.65
Operating expense	**13.15**	**6.72**	**10.25**	13.69	6.53	10.10
Transportation expense	**2.29**	**—**	**1.26**	2.93	—	1.46
Operating netback	**$ 25.94**	**$ 38.03**	**$ 31.39**	$ 12.08	$ 23.53	$ 17.83
Realized financial derivatives (loss) gain	**—**	**—**	**(4.07)**	—	—	0.44
Operating netback after financial derivatives	**$ 25.94**	**$ 38.03**	**$ 27.32**	$ 12.08	$ 23.53	$ 18.27

Risk Management

As part of our normal operations, we are exposed to movements in commodity prices. In an effort to manage these exposures, we utilize various financial derivative contracts, crude-by-rail and capital allocation optimization to reduce the volatility in our adjusted funds flow. We realized a financial derivatives loss of $31 million in Q3/2018 due to the increased price of crude oil relative to the prices set in our contracts.

For 2019, we have entered into hedges on approximately 35% of our net crude oil exposure. This includes 30% of our net WTI exposure with 11% fixed at US$61.22/bbl and 19% hedged utilizing a 3-way option structure that provides us with an average downside price protection at US$66.74/bbl and an average upside participation to US$73.42/bbl. In addition, we have entered into a Brent-based 3-way option structure for 3,000 bbl/d that provides us with average downside price protection at US$69.50/bbl and average upside participation to US$78.68/bbl.

Crude-by-rail is an integral part of our egress and marketing strategy. In Q3/2018, we delivered 9,500 bbl/d of our heavy oil volumes to market by rail, up from 8,500 bbl/d in Q2/2018. We have secured additional rail capacity, which will see our heavy oil volumes delivered to market by rail increase to approximately 11,000 bbl/d (approximately 40%) through 2019. Commencing January 1, 2019, approximately 70% of our crude by rail commitments are WTI based contracts with no WCS pricing exposure.

A complete listing of our financial derivative contracts can be found in Note 18 to our Q3/2018 financial statements.

Outlook and Guidance Update

On August 22, 2018, we provided updated 2018 guidance and preliminary plans for 2019. We laid out a plan to deliver industry leading returns, attractive production growth and strong free cash flow.

We are currently benefiting from improved WTI and LLS pricing, which has resulted in record operating netback being generated in the Eagle Ford. The Eagle Ford, which represents 37% of our production, generates approximately 47% of our operating netback and approximately $300 million of annual free cash flow. Likewise, the Viking, which represents 25% of our production, generates approximately 33% of our operating netback and approximately $100 million of annual free cash flow.

Offsetting the strong global pricing environment are weak prices for all grades of Canadian crude oil and in particular for heavy oil. Over the last two months, price differentials to WTI have widened due to an increased supply of crude oil from western Canada, refinery turnarounds in the U.S. which has temporarily reduced demand and a slower than anticipated ramp up in crude-by-rail volumes. As a result, based on the forward curve, the WCS differential to WTI for Q4/2018 is approximately US$40/bbl and for 2019, is approximately US$30/bbl.

We are committed to making prudent capital allocation decisions in the face of volatile commodity prices. In the normal pricing environment, our heavy oil assets generate exceptional rates of return and provide meaningful organic growth opportunities. Recognizing the current heavy oil pricing dynamics and an expectation that the volatility around heavy oil in Canada is likely to continue into 2019, we are currently optimizing our heavy oil operations. This includes building crude inventory, deferring several completions and pro-actively shutting in negative margin production. In doing so, we will maximize the value of our resource base and our adjusted funds flow.

Our heavy oil optimization strategy will reduce our Q4/2018 volumes by approximately 5,000 boe/d (90% oil), which represents 5% of our total production, and given current pricing, will have a minimal impact on our adjusted funds flow. The strong operating performance in our other business units is expected to mitigate a portion of the reduced heavy oil volumes in the fourth quarter. As a result, we expect production in Q4/2018 to average 95,000 to 96,000 boe/d (97,000 to 99,000 boe/d, previously). For the full-year 2018, we have tightened our production guidance range to 79,000 to 80,000 boe/d (79,000 to 81,000 boe/d, previously) with an unchanged exploration and development capital expenditure budget of $450 to $500 million.

The following table compares our 2018 annual guidance to our YTD 2018 results.

Summary of 2018 Guidance

	Original Guidance [1]	Current Guidance [2]	YTD Results
Exploration and development capital ($ millions)	450 – 500	450 - 500	312
Production (boe/d)	79,000 - 81,000	79,000 - 80,000	74,246
Expenses:			
Royalty rate (%)	~ 21.0	~ 22.0	23.0
Operating ($/boe)	10.75 - 11.25	10.50 – 10.75	10.54
Transportation ($/boe)	1.35 - 1.45	1.25 - 1.30	1.28
General and administrative ($ millions)	~ 48 (1.64/boe)	~ 45 (1.55/boe)	32 (1.57/boe)
Interest ($ millions)	~ 105 (3.60/boe)	~ 104 (3.58/boe)	76 (3.77/boe)

Note:

(1) As announced on August 22, 2018 to include Raging River from the closing date of the transaction.
(2) Updated as at November 2, 2018.

As we make plans for 2019, our top priority will be disciplined capital allocation to drive meaningful free cash flow and a strengthened balance sheet. With a diversified asset base and product pricing mix, we have the capability to optimize capital allocation based on commodity prices and economic returns by area.

In addition to the near-term impact of optimizing our heavy oil operations, we currently anticipate moderating our growth expectations in heavy oil over the near term. As a result, we are making plans for a curtailed heavy oil development program through the first half of 2019. We believe with continued growth in crude-by-rail volumes and incremental pipeline egress scheduled for late 2019, a much stronger pricing environment for heavy oil will present itself in the second half of 2019. We will continue to monitor Canadian crude oil pricing dynamics for an opportunity to re-deploy incremental capital as supported by well economics and field netbacks.

For our 2019 preliminary plans, exploration and development expenditures are now expected to total $650 to $750 million ($750 to $850 million previously) which is designed to generate average annual production of approximately 95,000 to 100,000 boe/d (100,000 to 105,000 boe/d, previously). This 2019 production range contemplates the re-start of shut in heavy oil volumes by mid-2019.

Preliminary development plans for 2019 include maintaining a consistent activity set in the Eagle Ford and Viking, both of which are expected to generate significant free cash flow. In addition, we will continue to delineate the East Duvernay Shale oil play with an increased pace of activity. Development plans for our heavy oil portfolio remain flexible based on an evolving outlook for heavy oil prices.

Despite the volatility in commodity prices, we continue to forecast adjusted funds flow for 2019 of approximately $900 million. With reduced spending on heavy oil, we are positioned to allocate approximately $200 million of free cash flow toward debt repayment, up from our original debt reduction plan of approximately $100 million.

Summary of Preliminary 2019 Plans

	Original (1)	Current (2)
Exploration and Development Capital	$750 - $850 million	$650 - $750 million
Production	100,000 - 105,000 boe/d	95,000 - 100,000 boe/d
Oil and NGLs	~ 85%	~ 85%
Operating Netback	$28/boe	$31/boe
Adjusted Funds Flow	$900 million	$900 million
Adjusted Funds Flow per Share (3)	$1.60	$1.60
Free Cash Flow after Total Capital Spending	$100 million	$200 million
Net Debt (YE 2019)	$2.0 billion	$1.9 billion
Net Debt to Adjusted Funds Flow (4)	2.2x	2.1x

Notes:

(1) As announced August 22, 2018. Pricing assumptions: WTI - US$63/bbl; LLS - US$67/bbl; WCS differential - US$23/bbl; MSW differential – US$8/bbl, NYMEX Gas - US$2.80/mcf; and Exchange Rate (CAD/USD) - 1.30.
(2) As announced November 2, 2018. Pricing assumptions: WTI - US$70/bbl; LLS - US$75/bbl; WCS differential - US$30/bbl; MSW differential – US$15/bbl, NYMEX Gas - US$2.90/mcf; and Exchange Rate (CAD/USD) - 1.30.
(3) Based on 555 million common shares outstanding.
(4) Net debt ratio based on forecast net debt at year-end 2019 and forecast 2019 adjusted funds flow.
(5) Certain terms referenced above are non-GAAP measures. See advisory regarding Non-GAAP Financial and Capital Management Measures at the end of the press release.

We will provide 2019 guidance in early December upon approval by the board of directors.

Advisory Regarding Forward-Looking Statements

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

Specifically, this press release contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that we benefit from oil price diversification; that our top priority is disciplined capital allocation to drive meaningful free cash flow; that we are a well-capitalized, oil-weighted company with an attractive free cash flow profile and an improved balance sheet; our reduced guidance for 2018 operating and general and administrative expenses; the impact of our heavy oil optimization strategy; our plans to optimize heavy oil prices, including: the volume of oil we expect to deliver to market by rail and the percentage of our rail commitments exposed to WCS pricing; our 2019 preliminary plans, including our expected: adjusted funds flow, percentage of adjusted funds flow to be derived from our light oil assets, capital spending plan, cash flow above capital expenditures and free cash flow yield; that we are a self-funded producer focused on per share value creation, targeting shareholder returns of 10% to 15%; that our drilling prospects will generate top tier returns on invested capital and that we have the ability to deliver meaningful organic production growth; our commodity exposure on a production, revenue and proved reserves basis; our Eagle Ford assets, including our assessment that: it is a premier oil resource play, generates strong operating netbacks and free cash flow and has a significant development inventory; that 460 net sections in our Viking asset are prospective; our assessment that we can generate some of the strongest capital efficiencies in the oil and gas industry at our Peace River assets; that polymer flooding will enhance reserves recovery at our Lloydminster asset; our East Duvernay assets, including: that we are prudently advancing the evaluation of the play, our plan to complete two wells in November, that the Pembina area will be a focus of pad drilling and incremental delineation drilling in 2019; our belief that we have strong financial liquidity; our ability to partially reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts, crude-by-rail and capital allocation optimization; the percentage of our net WTI exposure that we have hedged for 2019; the percentage of production and cash flow and dollar amount of free cash flow expected from our Eagle Ford and Viking assets in 2019; that our heavy oil assets generate exceptional rates of return and provide meaningful growth opportunities in the right pricing environment; our expectation the heavy oil prices will remain volatile into 2019; that we are maximizing the value of our heavy oil resource base and adjusted funds flow by and will: build inventory, defer completions and shut-in low or negative margin production; the expected impact of our heavy oil optimization in Q4/2018 on production and adjusted fuds flow; that strong performance in other business units will mitigate the a portion of the heavy oil reduction; our 2018 guidance for exploration and development capital, production and royalty rate, operating, transportation, general and administration and interest expenses; our top priority for 2019 will be disciplined capital allocation to drive meaningful cash flow and a strengthened balance sheet; that we have the ability to optimize capital allocation based on commodity prices and economic returns by area; our preliminary plans for 2019, including: moderated growth in heavy oil, that heavy oil prices will be higher in the second half of 2019, 2019 guidance for exploration and development capital and production, that we will re-start shut in heavy oil volumes by mid-2019, that we will have a consistent activity set in the Eagle Ford and Viking that will generate significant free cash flow, that we will continue to delineate the Duvernay, that our heavy oil development will be flexible, our forecast adjusted funds flow, the amount of free cash flow available for debt repayment, our Summary of Preliminary 2019 Plans and that we will provide 2019 guidance in early December upon approval by the board of directors.

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, asset retirement obligations settled and transaction costs. 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. In addition, we have removed transaction costs from the Raging River combination as we consider these costs non-recurring and not reflective of our ongoing ability to generate 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 nine months ended September 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 nine months ended September 30, 2018. This information is provided as of November 1, 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 nine months ended September 30, 2018 ("Q3/2018" and "YTD 2018") have been compared with the results for the three and nine months ended September 30, 2017 ("Q3/2017" 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 nine months ended September 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.

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 advisory on forward-looking information and statements and a summary of our non-GAAP measures at the end of our MD&A.

THIRD QUARTER HIGHLIGHTS

Business combination

On August 22, 2018, Baytex and Raging River Exploration Inc. ("Raging River") completed the strategic combination of the two companies (the "Strategic Combination") by way of a plan of arrangement whereby Baytex acquired all of the issued and outstanding common shares of Raging River. The Strategic Combination increases our light oil exposure while improving our leverage ratios and increasing operational control of our properties. Production from Raging River's properties is approximately 90% weighted towards high netback light oil. The Strategic Combination has also strengthened our balance sheet and resulted in a decrease in our net debt to Bank EBITDA ratio to 2.3 for Q3/2018 compared to a ratio of 4.4 in Q2/2018. The addition of the primarily operated assets to our portfolio increases our inventory of drilling prospects and increases our ability to effectively allocate capital.

Operating and financial results include Raging River operations from the closing date of August 22, 2018. Production from the properties averaged approximately 23,750 boe/d between closing and September 30, 2018 which contributed 10,300 boe/d and 3,500 boe/d of average daily production to Q3/2018 and YTD 2018, respectively. The Companies began integration in Q3/2018 and operations have continued in-line with expectations for both the legacy Baytex and Raging River assets. Baytex issued 315.3 million common shares and assumed Raging River's net debt of approximately $363.6 million million at closing of the transaction.

Third quarter operating and financial results

Baytex delivered strong operating and financial results during Q3/2018. We generated adjusted funds flow of $171.2 million which exceeded our investment on exploration and development activities of $139.2 million by $32.0 million. Average daily production of 82,412 boe/d was 17% higher compared to 70,664 boe/d for Q2/2018 and 19% higher than 69,310 boe/d reported for Q3/2017. The increase reflects the production contribution from the Strategic Combination along with strong well performance in both our legacy Canadian and U.S operations.

We invested $94.5 million on exploration and development activities in Canada during Q3/2018 compared to $30.6 million in Q2/2018 and $14.5 million in Q3/2017. We had an active capital program in Canada which was focused on our heavy oil properties at Peace River and Lloydminster along with our Viking and Duvernay light oil properties. The production contribution from the Strategic Combination combined with strong well performance resulted in average production of 45,214 boe/d during Q3/2018 which is 33% higher than 34,042 boe/d for Q2/2018 and 31% higher than 34,560 boe/d for Q3/2017.

In the U.S., we invested $44.7 million on exploration and development activity during Q3/2018 and drilled 29 (8.0 net) wells and commenced production from 26 (4.9 net) wells. We continue to see strong well performance from enhanced completions techniques utilizing higher proppant loading and increased frac stages in 2018 compared to 2017. Wells that commenced production during Q3/2018 have established 30-day initial gross production rates of approximately 1,600 boe/d per well. U.S production of 37,198 boe/d for Q3/2018 increased from 36,622 boe/d for Q2/2018 and 34, 750 boe/d for Q3 2017 due to strong well performance for wells brought online during YTD 2018.

During 2018, strong global oil demand along with ongoing 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$69.50/bbl for Q3/2018 which is an increase of 44% from US$48.20/bbl for Q3/2017. The LLS benchmark price continued to improve relative to WTI a result of higher global crude oil pricing and traded at a US$5.75/bbl premium to WTI in Q3/2018 compared to a US$2.07/bbl premium in Q3/2017. The improvement in WTI market prices was partially offset by wider light and heavy oil differentials in Canada and resulted in a 45% increase in our realized sales price to $55.03/boe in Q3/2018 from $38.04/boe in Q3/2017. The ongoing lack of takeaway capacity for light and heavy grades of Canadian crude oil combined with increasing crude oil production in Western Canada resulted in a widening of the price differential for Canadian oil relative to WTI. The Edmonton par oil price traded at a US$6.82/boe discount to WTI during Q3/2018 compared to a discount of US$2.89/bbl during Q3/2017 while the Canadian heavy oil price differential to WTI widened to US$22.25/bbl in Q3/2018 from US$9.94/bbl in Q3/2017.

We generated adjusted funds flow of $171.2 million for Q3/2018, an increase of $93.8 million from adjusted funds flow of $77.3 million reported for Q3/2017. Stronger realized pricing combined with the increase in average daily production resulted in an operating netback of $238.1 million for Q3/2018 which was $124.4 million higher than Q3/2017. Higher realized prices and production resulted in a $174.7 million increase in total sales, net of blending and other expense, relative to Q3/2017. This was offset by $50.3 million from higher royalties with increased revenue and by higher operating and transportation expense from increased production. The increase in operating netback was offset by realized hedging losses of $30.9 million in Q3/2018 as compared to gains of $2.8 million for Q3/2017. Net income was $27.4 million for Q3/2018 reflecting our strong operating and financial results for the quarter.

At September 30, 2018, net debt was $2,112.1 million, an increase of $377.8 million from $1,734.3 million at December 31, 2017. The increase is primarily due to the $363.6 million of net debt assumed on closing of the Strategic Combination in Q3/2018. Despite the increase in net debt, our net debt to Bank EBITDA ratio has decreased to 2.3 due to the Strategic Combination and the inclusion of the Raging River EBITDA on a trailing basis.

RESULTS OF OPERATIONS

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

Production

	Three Months Ended September 30					
	2018			2017		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Light oil and condensate	**9,894**	**19,837**	**29,731**	1,245	18,796	20,041
Heavy oil	**27,036**	**—**	**27,036**	26,161	—	26,161
Natural Gas Liquids (NGL)	**1,096**	**8,980**	**10,076**	1,126	7,814	8,940
Total liquids (bbl/d)	**38,026**	**28,817**	**66,843**	28,532	26,610	55,142
Natural gas (mcf/d)	**43,127**	**50,287**	**93,414**	36,164	48,842	85,006
Total production (boe/d)	**45,214**	**37,198**	**82,412**	34,560	34,750	69,310
Production Mix						
Light oil and condensate	**22%**	**53%**	**36%**	4%	54%	29%
Heavy oil	**60%**	**—%**	**33%**	76%	—%	38%
NGL	**2%**	**24%**	**12%**	3%	23%	13%
Natural gas	**16%**	**23%**	**19%**	17%	23%	20%

	Nine Months Ended September 30					
	2018			2017		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Light oil and condensate	**3,898**	**20,067**	**23,965**	1,258	20,085	21,343
Heavy oil	**25,824**	**—**	**25,824**	25,454	—	25,454
Natural Gas Liquids	**1,202**	**8,347**	**9,549**	1,063	7,919	8,982
Total liquids (bbl/d)	**30,924**	**28,414**	**59,338**	27,775	28,004	55,779
Natural gas (mcf/d)	**40,232**	**49,217**	**89,449**	37,502	50,664	88,166
Total production (boe/d)	**37,629**	**36,617**	**74,246**	34,025	36,448	70,473
Production Mix						
Light oil and condensate	**10%**	**55%**	**32%**	4%	55%	30%
Heavy oil	**69%**	**—%**	**35%**	75%	—%	36%
NGL	**3%**	**23%**	**13%**	3%	22%	13%
Natural gas	**18%**	**22%**	**20%**	18%	23%	21%

We reported average production of 82,412 boe/d for Q3/2018 and 74,246 boe/d for YTD 2018 compared to 69,310 boe/d in Q3/2017 and 70,473 boe/d in YTD 2017. The increase in production for Q3/2018 and YTD 2018 compared to the same periods of 2017 is primarily due to the Strategic Combination which closed on August 22, 2018 and added approximately 10,300 boe/d to Q3/2018 production and 3,500 boe/d to YTD 2018 production.

Average daily production in Canada was 45,214 boe/d for Q3/2018 and 37,629 boe/d for YTD 2018 compared to 34,560 boe/d in Q3/2017 and 34,025 boe/d for YTD 2017. The increase in production in 2018 relative to 2017 is primarily due to the production contribution from the Strategic Combination. Production from our Viking and Duvernay properties consists of approximately 90% light oil which resulted in a higher portion of our Canadian production being comprised of light oil in 2018 relative to 2017. Canadian results, excluding the Strategic Combination, for Q3/2018 and YTD 2018 were in line with expectations and relatively consistent with the same periods of 2017.

In the U.S., production averaged 37,198 boe/d for Q3/2018 and 36,617 boe/d for YTD 2018. Strong well performance from 85 (17.9 net) wells that commenced production during YTD 2018 resulted in average daily production that was consistent with 36,448 boe/d in YTD 2017 when 90 (23.3 net) wells were brought on production. Improved well productivity contributed to the increase in daily production to 37,198 boe/d for Q3/2018 compared to 34,750 boe/d for Q3/2017 which was also impacted by an estimated 1,500 boe/d of downtime associated with Hurricane Harvey.

Our production of 74,246 boe/d for YTD 2018 increased from 70,473 boe/d reported for YTD 2017 primarily from the Strategic Combination. We expect our annual production for 2018 to be in line with our updated annual guidance range of 79,000 to 80,000 boe/d.

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 continued to strengthen into Q3/2018 as robust global demand and ongoing 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$69.50/bbl during Q3/2018, representing an increase of 44% compared to Q3/2017 when the benchmark price averaged US$48.20/bbl. During YTD 2018, the WTI benchmark price averaged US$66.75/bbl representing a 35% increase relative to an average of US$49.46/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 Q3/2018 averaging US$75.25/bbl which is 50% higher than US$50.27/bbl during Q3/2017. 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$71.24/bbl, which is a premium of US$4.49/bbl relative to WTI, compared to US$50.82/bbl or a US$1.36/bbl premium to WTI for the same period of 2017.

Benchmark prices for Canadian light and heavy grades of crude oil improved in 2018 relative to 2017 but traded at a wider discount to WTI due to ongoing pipeline capacity constraints, a lack of rail transport capacity and increasing Western Canadian crude oil production. We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $81.92/bbl in Q3/2018 and $78.19/bbl for YTD 2018 compared to $56.74/bbl in Q3/2017 and $60.87/bbl for YTD 2017. During YTD 2018, Edmonton par traded at a US$6.03/bbl discount to WTI compared to a US$2.88/boe discount 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 is the representative benchmark for heavy grades of crude oil in Western Canada. The WCS heavy oil differential to WTI averaged US$22.25/bbl in Q3/2018 and US$21.93/bbl in YTD 2018 as compared to US$9.94/bbl and US$11.87/bbl for the same periods of 2017.

Natural Gas

North American natural gas prices were lower during YTD 2018 relative to YTD 2017 as natural gas supply growth outpaced growth in demand. Canadian natural gas prices remained challenged during YTD 2018 as a lack of egress in Western Canada continues to impact 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 Q3/2018 and YTD 2018, the NYMEX natural gas benchmark averaged US$2.90/mmbtu representing a 3% and 9% decrease from the same periods in 2017.

In Canada, we receive natural gas pricing based on the AECO benchmark which continues to trade at a significant discount to NYMEX as a result of increasing supply and limited market access for Canadian natural gas production. The benchmark averaged $1.35/mcf during Q3/2018 and $1.41/mcf during YTD 2018 which is 34% and 45% lower than the benchmark averages of $2.04/mcf and $2.58/mcf during the comparative periods in 2017.

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

	Three Months Ended September 30			Nine Months Ended September 30		
	2018	2017	Change	**2018**	2017	Change
Benchmark Averages						
WTI oil (US$/bbl)(1)	**69.50**	48.20	44 %	**66.75**	49.46	35 %
WTI oil (CAD$/bbl)	**90.84**	60.37	50 %	**85.96**	64.63	33 %
WCS heavy oil differential (US$/bbl)	**(22.25)**	(9.94)	124 %	**(21.93)**	(11.87)	85 %
WCS heavy oil differential (CAD$/bbl)	**(29.08)**	(12.45)	134 %	**(28.25)**	(15.52)	82 %
WCS heavy oil (US$/bbl)(2)	**47.25**	38.26	23 %	**44.82**	37.59	19 %
WCS heavy oil (CAD$/bbl)	**61.76**	47.92	29 %	**57.71**	49.11	18 %
LLS oil (US$/bbl)(3)	**75.25**	50.27	50 %	**71.24**	50.82	40 %
LLS oil (CAD$/bbl)	**98.35**	62.96	56 %	**91.74**	66.41	38 %
CAD/USD average exchange rate	**1.3070**	1.2524	4 %	**1.2877**	1.3067	(1)%
Edmonton par oil ($/bbl)	**81.92**	56.74	44 %	**78.19**	60.87	28 %
AECO natural gas price ($/mcf)(4)	**1.35**	2.04	(34)%	**1.41**	2.58	(45)%
NYMEX natural gas price (US$/mmbtu)(5)	**2.90**	3.00	(3)%	**2.90**	3.17	(9)%

(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 September 30					
	2018			2017		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices(1)						
Light oil and condensate ($/bbl)	**$ 76.42**	**$ 93.37**	**$ 87.73**	$ 52.57	$ 58.59	$ 58.22
Heavy oil ($/bbl)(2)	**48.15**	**—**	**48.15**	38.18	—	38.18
NGL ($/bbl)	**41.11**	**36.93**	**37.38**	25.06	25.20	25.18
Natural gas ($/mcf)	**1.21**	**3.90**	**2.66**	1.72	3.76	2.89
Weighted average ($/boe)(2)	**$ 47.66**	**$ 63.98**	**$ 55.03**	$ 33.41	$ 42.64	$ 38.04

	Nine Months Ended September 30					
	2018			2017		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices(1)						
Light oil and condensate ($/bbl)	**$ 75.08**	**$ 86.90**	**$ 84.98**	$ 54.77	$ 61.13	$ 60.75
Heavy oil ($/bbl)(2)	**43.95**	**—**	**43.95**	37.29	—	37.29
NGL ($/bbl)	**35.33**	**31.37**	**31.87**	27.70	24.24	24.65
Natural gas ($/mcf)	**1.39**	**3.80**	**2.72**	2.35	4.09	3.35
Weighted average ($/boe)(2)	**$ 40.56**	**$ 59.89**	**$ 50.09**	$ 33.37	$ 44.64	$ 39.20

(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 $50.09/boe for YTD 2018, up $10.89/boe from $39.20/boe for the first nine 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. Our realized pricing has also improved following the Strategic Combination which resulted in a higher proportion of our Canadian production being higher value light oil from our Viking and Duvernay properties.

In Canada, our realized light oil and condensate price of $76.42/bbl for Q3/2018 and $75.08/bbl for YTD 2018 increased from $52.57/bbl for Q3/2017 and $54.77/bbl for YTD 2017, due to the increase in market prices for crude oil over the same periods. The increase in our realized light oil pricing for Q3/2018 and YTD 2018 also reflects light oil production from our Viking and Duvernay properties which produce a higher quality light oil and achieves stronger price realizations than our pre-existing Canadian properties. As a result, the increase in our realized light oil and condensate price for Q3/2018 and YTD 2018 was higher than the increase in Edmonton par pricing relative to the same periods of 2017.

Our realized Canadian heavy oil sales price, net of blending and other expense, averaged $48.15/bbl for Q3/2018 and $43.95/bbl for YTD 2018 which is $9.97/bbl and $6.66/bbl higher than realized pricing of $38.18/bbl for Q3/2017 and $37.29/bbl for YTD 2017. Our Canadian heavy oil production is blended with diluent in order to meet pipeline transportation specifications. The price received for the blended product is recorded as heavy oil sales revenue while the cost of blending diluent is recorded as blending and other expense. We include the cost of blending diluent in our realized heavy oil sales price in order to compare the realized pricing on our produced volumes to the WCS benchmark. The increase in our realized heavy oil sale price, net of blending and other expense, is primarily due to the $13.84/bbl and $8.60/bbl increase in the WCS benchmark in Q3/2018 and YTD 2018 relative to the same periods of 2017. Our realized heavy oil price in 2018 did not increase as much as the WCS benchmark price as the cost of blending diluent has increased more than the increase in the benchmark price.

In the U.S., our realized light oil and condensate price was $93.37/bbl for Q3/2018 and $86.90/bbl for YTD 2018 compared to $58.59/bbl for Q3/2017 and $61.13/bbl for YTD 2017. The $34.78/bbl and $25.77/bbl increase in our realized light oil and condensate pricing for Q3/2018 and YTD 2018 was consistent with the increase in the LLS benchmark price (expressed in Canadian dollars) of $35.39/bbl and $25.33/bbl since the same periods of 2017.

For Q3/2018, our realized NGL price was $37.38/bbl or 41% of WTI (expressed in Canadian dollars) compared to $25.18/bbl or 41% of WTI in Q3/2017. Our realized NGL price for YTD 2018 was $31.87/bbl or 35% of WTI (expressed in Canadian dollars) relative to $24.65/bbl or 38% 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.

Our realized natural gas price in Canada was $1.21/mcf for Q3/2018 and $1.39/mcf for YTD 2018 compared to realized pricing of $1.72/mcf in Q3/2017 and $2.35/mcf in YTD 2017. The decrease is primarily due to lower AECO benchmark pricing in Q3/2018 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 Q3/2018 and YTD 2018 decreased by $0.51/mcf and $0.96/mcf relative to a $0.69/mcf and $1.17/mcf decrease in the AECO monthly average relative to the same periods of 2017.

Our U.S. realized natural gas price was $3.90/mcf in Q3/2018 and $3.80/mcf for YTD 2018 compared to $3.76/mcf for Q3/2017 and $4.09/mcf for YTD 2017. The change in our realized pricing reflects changes in the NYMEX natural gas benchmark (expressed in Canadian dollars) which was was $0.03/mcf higher in Q3/2018 relative to Q3/2017 and $0.41/mcf lower in YTD 2018 relative to YTD 2017.

Petroleum and Natural Gas Sales

	Three Months Ended September 30					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 69,557**	**$ 170,402**	**$ 239,959**	$ 6,024	$ 101,320	$ 107,344
Heavy oil	**139,305**	**—**	**139,305**	107,972	—	107,972
NGL	**4,147**	**30,508**	**34,655**	2,596	18,116	20,712
Total liquids sales	**213,009**	**200,910**	**413,919**	116,592	119,436	236,028
Natural gas sales	**4,796**	**18,046**	**22,842**	5,715	16,877	22,592
Total petroleum and natural gas sales	**217,805**	**218,956**	**436,761**	122,307	136,313	258,620
Blending and other expense	**(19,548)**	**—**	**(19,548)**	(16,069)	—	(16,069)
Total sales, net of blending and other expense	**$ 198,257**	**$ 218,956**	**$ 417,213**	$ 106,238	$ 136,313	$ 242,551

Nine Months Ended September 30						
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 79,894**	**$ 476,086**	**$ 555,980**	$ 18,808	$ 335,190	$ 353,998
Heavy oil	**364,957**	**—**	**364,957**	301,663	—	301,663
NGL	**11,595**	**71,480**	**83,075**	8,040	52,395	60,435
Total liquids sales	**456,446**	**547,566**	**1,004,012**	328,511	387,585	716,096
Natural gas sales	**15,296**	**51,125**	**66,421**	24,011	56,599	80,610
Total petroleum and natural gas sales	**471,742**	**598,691**	**1,070,433**	352,522	444,184	796,706
Blending and other expense	**(55,077)**	**—**	**(55,077)**	(42,554)	—	(42,554)
Total sales, net of blending and other expense	**$ 416,665**	**$ 598,691**	**$ 1,015,356**	$ 309,968	$ 444,184	$ 754,152

Total sales, net of blending and other expense, was $417.2 million for Q3/2018 which is an increase of $174.7 million or 72% from $242.6 million reported for Q3/2017. Higher average daily production in Q3/2018 was primarily a result of the incremental production from the Strategic Combination which increased sales by $67.0 million relative to Q3/2017. Improved commodity prices combined with a higher weighting of light oil production resulted in stronger realized pricing in Q3/2018 and increased sales by $107.7 million relative to the same period of 2017.

In Canada, total sales, net of blending and other expense, were $198.3 million for Q3/2018, up $92.0 million or 87% from $106.2 million in the same period of 2017. Average daily production in Canada was approximately 10,700 boe/d or 31% higher in Q3/2018 compared to the same quarter of 2017. The majority of the increase can be attributed to the 10,300 boe/d of incremental production associated with the Strategic Combination. A higher proportion of our Canadian production mix was light oil in Q3/2018 relative to Q3/2017 and, combined with the improvement in benchmark pricing, contributed to the $14.25/boe or 42% increase in our weighted average realized price.

Petroleum and natural gas sales of $219.0 million during Q3/2018 in the U.S. increased 61% or $82.6 million from $136.3 million reported for Q3/2017. The increase was driven by higher benchmark pricing which resulted in a $21.34/boe or 50% increase in our weighted average realized price for Q3/2018 compared to Q3/2017. Average daily production in the U.S. was also up approximately 2,400 boe/d or 7% in Q3/2018 due to strong well performance and the impact of Hurricane Harvey which reduced production for Q3/2017 by an estimated 1,500 boe/d.

Total sales, net of blending and other expense, of $1,015.4 million for YTD 2018 were $261.2 million or 35% higher than $754.2 million reported for the first nine months of 2017. Benchmark prices for crude oil have been higher during YTD 2018 which resulted in a 28% increase in our weighted averaged realized price and a $209.6 million increase in total sales, net of blending and other expense, relative to YTD 2017. Average daily production of 74,246 boe/d for YTD 2018 was higher compared to 70,473 boe/d for YTD 2017 primarily due to the 3,500 boe/d of incremental production from the Strategic Combination and resulted in a $51.6 million increase in total sales, net of blending and other expense.

Royalties

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

Three Months Ended September 30						
	2018			2017		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 26,139**	**$ 65,806**	**$ 91,945**	$ 14,973	$ 40,203	$ 55,176
Average royalty rate[(1)]	**13.2%**	**30.1%**	**22.0%**	14.1%	29.5%	22.7%
Royalty rate per boe	**$ 6.28**	**$ 19.23**	**$ 12.13**	$ 4.71	$ 12.58	$ 8.65

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

Nine Months Ended September 30						
	2018			2017		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 55,471**	**$ 178,518**	**$ 233,989**	$ 41,725	$ 130,642	$ 172,367
Average royalty rate(1)	**13.3%**	**29.8%**	**23.0%**	13.5%	29.4%	22.9%
Royalty rate per boe	**$ 5.40**	**$ 17.86**	**$ 11.54**	$ 4.49	$ 13.13	$ 8.96

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

Total royalties for Q3/2018 were $91.9 million and averaged 22.0% of total sales, net of blending and other expense, which is higher than $55.2 million or 22.7% for Q3/2017. Total royalties were $234.0 million for YTD 2018 and averaged 23.0% of total sales, net of blending and other expense, as compared to $172.4 million and 22.9% reported for YTD 2017. Royalty expense is higher in 2018 due to higher total sales, net of blending and other expense, in Canada and the U.S. relative to 2017. The average royalty rate in Canada was lower following the Strategic Combination as the royalty rate on our Viking properties was approximately 9.6% for Q3/2018, resulting in a lower average royalty rate in Canada compared to Q3/2017. In the U.S., royalties for Q3/2018 and YTD 2018 averaged 30.1% and 29.8% 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. Our average royalty rate of 23.0% for YTD 2018 is slightly higher than our 2018 annual guidance of approximately 22.0%. We are maintaining annual guidance of approximately 22.0% for 2018 as we expect the lower royalty rate on production from the Strategic Combination to reduce our corporate average royalty rate through the remainder of 2018.

Operating Expense

Three Months Ended September 30						
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Operating expense	**$ 54,710**	**$ 22,988**	**$ 77,698**	$ 43,525	$ 20,866	$ 64,391
Operating expense per boe	**$ 13.15**	**$ 6.72**	**$ 10.25**	$ 13.69	$ 6.53	$ 10.10

Nine Months Ended September 30						
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Operating expense	**$ 147,054**	**$ 66,681**	**$ 213,735**	$ 132,908	$ 66,538	$ 199,446
Operating expense per boe	**$ 14.31**	**$ 6.67**	**$ 10.54**	$ 14.31	$ 6.69	$ 10.37

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

Operating expense of $10.25/boe for Q3/2018 and $10.54/boe for YTD 2018 is consistent with the low end our annual guidance range of $10.50 - $10.75/boe. Total operating expense was $77.7 million ($10.25/boe) for Q3/2018 and $213.7 million ($10.54/boe) for YTD 2018 compared to $64.4 million ($10.10/boe) for Q3/2017 and $199.4 million ($10.37/boe) for YTD 2017.

In Canada, operating expense was $54.7 million ($13.15/boe) for Q3/2018 and $147 million ($14.31/boe) for YTD 2018 compared to $43.5 million ($13.69/boe) for Q3/2017 and $132.9 million ($14.31/boe) for YTD 2017. Total operating expense in Canada has increased following the closing of the Strategic Combination as these properties contributed approximately $11.1 million of operating expense in Q3/2018. Per unit operating expense in Canada was slightly lower in Q3/2018 compared to Q3/2017 as per unit operating costs on our Viking and Duvernay properties are lower relative to our other Canadian properties. Total operating expense in Canada is higher in YTD 2018 compared to YTD 2017 due to costs incurred to support higher average daily production in YTD 2018 and operating expenses associated with our Viking and Duvernay properties.

U.S. operating expense of $23.0 million ($6.72/boe) for Q3/2018 and $66.7 million ($6.67/boe) for YTD 2018 was relatively consistent with $20.9 million ($6.53/boe) for Q3/2017 and $66.5 million ($6.69/boe) for YTD. The reported amount of our U.S. operating expense expressed in Canadian dollars changes with fluctuations in the CAD/USD exchange rate which was 1.2877 CAD/USD in YTD 2018 as compared to 1.3067 CAD/USD in YTD 2017. Expressed in U.S. dollars, operating expense for our U.S. properties was US$5.14/boe in Q3/2018 and US$5.18/boe during YTD 2018 which is fairly consistent with US$5.21/boe for Q3/2017 and US$5.12/boe in YTD 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 oil in Canada to pipeline and rail terminals which can vary from period to period depending on hauling distances as we seek to optimize sales prices and trucking rates. The following table compares our transportation expense for the three and nine months ended September 30, 2018 and 2017.

	Three Months Ended September 30					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.[1]**	**Total**	Canada	U.S.[1]	Total
Transportation expense	**$ 9,520**	**$ —**	**$ 9,520**	$ 9,312	$ —	$ 9,312
Transportation expense per boe	**$ 2.29**	**$ —**	**$ 1.26**	$ 2.93	$ —	$ 1.46

	Nine Months Ended September 30					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.[1]**	**Total**	Canada	U.S.[1]	Total
Transportation expense	**$ 25,875**	**$ —**	**$ 25,875**	$ 26,327	$ —	$ 26,327
Transportation expense per boe	**$ 2.52**	**$ —**	**$ 1.28**	$ 2.83	$ —	$ 1.37

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

Transportation expense was $9.5 million ($1.26/boe) for Q3/2018 and $25.9 million ($1.28/boe) for YTD 2018 compared to $9.3 million ($1.46/boe) for Q3/2017 and $26.3 million ($1.37/boe) for YTD 2017. Gas transportation costs were slightly lower for YTD 2018 relative to YTD 2017 as a result of a change in certain marketing arrangements. The decrease in gas transportation costs for YTD 2018 was partially offset by higher oil trucking costs of approximately $1.5 million ($1.58/boe) associated with the Strategic Combination. Per unit transportation expense $1.28/boe is slightly below our annual guidance range of $1.35 - $1.45/boe for 2018 due to additional production associated with the Strategic Combination.

Blending and Other Expense

Blending and other expense primarily includes the cost of blending diluent purchased in order to reduce the viscosity of our heavy oil transported through pipelines to meet pipeline specifications. The purchased diluent is recorded as blending and other expense. The price received for the blended product is recorded as heavy oil sales revenue. We net blending and other expense against heavy oil sales to compare the realized price on our produced volumes to benchmark pricing. Accordingly, our heavy oil sales price realization can fluctuate depending on the quantity and price of blending diluent required to meet pipeline specifications.

Blending and other expense was $19.5 million for Q3/2018 and $55.1 million for YTD 2018 compared to $16.1 million for Q3/2017 and $42.6 million for the first nine months of 2017. The increase in blending and other expense during Q3/2018 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 purchases of blending diluent 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 nine months ended September 30, 2018 and 2017.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2018**	2017	Change	**2018**	2017	Change
Realized financial derivatives gain (loss)						
Crude oil	**$ (31,704)**	$ 972	$ (32,676)	**$ (72,529)**	$ 4,828	$ (77,357)
Natural gas	**872**	1,823	(951)	**2,448**	891	1,557
Interest and financing	**(22)**	—	(22)	**(22)**	—	(22)
Total	**$ (30,854)**	$ 2,795	$ (33,649)	**$ (70,103)**	$ 5,719	$ (75,822)
Unrealized financial derivatives gain (loss)						
Crude oil	**$ 4**	$ (21,912)	$ 21,916	**$ (63,454)**	$ 13,936	$ (77,390)
Natural gas	**(1,027)**	767	(1,794)	**(2,663)**	13,762	(16,425)
Interest and financing	**977**	—	977	**977**	—	977
Total	**$ (46)**	$ (21,145)	$ 21,099	**$ (65,140)**	$ 27,698	$ (92,838)
Total financial derivatives gain (loss)						
Crude oil	**$ (31,700)**	$ (20,940)	$ (10,760)	**$ (135,983)**	$ 18,764	$ (154,747)
Natural gas	**(155)**	2,590	(2,745)	**(215)**	14,653	(14,868)
Interest and financing	**955**	—	955	**955**	—	955
Total	**$ (30,900)**	$ (18,350)	$ (12,550)	**$ (135,243)**	$ 33,417	$ (168,660)

Realized financial derivatives losses of $30.9 million for Q3/2018 and $70.1 million for YTD 2018 are primarily a result of the market prices for crude oil settling at levels above those set in our derivative contracts.

Our realized crude oil losses of $72.5 million for YTD 2018 were driven by $71.5 million of losses on our WTI swap contracts and $16.1 million of losses on our Brent swap contracts as the market price of WTI and Brent settled above our contract prices. We also recorded $4.8 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 $19.9 million on our WCS differential contracts as the index was wider than the differentials set in our contracts throughout the first nine months of 2018.

We recorded realized gains of $2.4 million on our natural gas financial derivatives during YTD 2018. These gains were primarily a result of the AECO price index for the first nine months of 2018 averaging less than the average fixed price on AECO contracts in place for YTD 2018.

At September 30, 2018, the fair value of our financial derivative contracts represent a net liability of $102.3 million compared to a net liability of $31.6 million at December 31, 2017. The net liability of $102.3 million as at September 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 November 1, 2018.

	Period	Volume	Price/Unit[1]	Index
Oil				
Basis swap	Oct 2018 to Dec 2018	6,000 bbl/d	WTI less US$14.24/bbl	WCS
3-way option[2]	Oct 2018 to Dec 2018	2,000 bbl/d	US$60.00/US$54.40/US$40.00	WTI
Fixed - Sell	Oct 2018 to Dec 2018	16,500 bbl/d	US$52.28/bbl	WTI
Fixed - Sell	Oct 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$72.60/US$65.00/US$55.00	WTI
3-way option[2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$72.50/US$66.00/US$56.00	WTI
3-way option[2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$73.00/US$66.00/US$56.00	WTI
3-way option[2]	Jan 2019 to Dec 2019	2,000 bbl/d	US$73.00/US$67.00/US$57.00	WTI
3-way option[2]	Jan 2019 to Dec 2019	2,000 bbl/d	US$74.00/US$68.00/US$58.00	WTI
3-way option[2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.00/US$69.90/US$60.00	WTI
3-way option[2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$76.00/US$71.00/US$61.00	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
3-way option[2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$78.00/US$73.00/US$63.00	WTI
Natural Gas				
Fixed - Sell	Oct 2018 to Dec 2018	15,000 mmbtu/d	US$3.01	NYMEX
Fixed - Sell	Oct 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO
Fixed - Sell	Nov 2018 to Mar 2019	5,000 GJ/d	$2.25	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$70/US$60/US$50 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50/bbl; Baytex receives US$60.00/bbl when WTI is between US$50/bbl and US$60/bbl; Baytex receives the market price when WTI is between US$60/bbl and US$70/bbl; and Baytex receives US$70/bbl when WTI is above US$70/bbl.

(3) For these contracts, the counterparty has the right, if exercised on December 31, 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 November 1, 2018, Baytex had committed to deliver the following volumes of raw bitumen to market on rail:

Period	Volume
Oct 2018 to Dec 2018	8,340 bbl/d
Nov 2018 to Oct 2019	1,000 bbl/d
Oct 2018 to Dec 2019	2,500 bbl/d
Jan 2019 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 nine months ended September 30, 2018 and 2017.

	Three Months Ended September 30					
	2018			2017		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**45,214**	**37,198**	**82,412**	34,560	34,750	69,310
Operating netback:						
Total sales, net of blending and other expense	**$ 47.66**	**$ 63.98**	**$ 55.03**	$ 33.41	$ 42.64	$ 38.04
Less:						
Royalties	**6.28**	**19.23**	**12.13**	4.71	12.58	8.65
Operating expense	**13.15**	**6.72**	**10.25**	13.69	6.53	10.10
Transportation expense	**2.29**	**—**	**1.26**	2.93	—	1.46
Operating netback	**$ 25.94**	**$ 38.03**	**$ 31.39**	$ 12.08	$ 23.53	$ 17.83
Realized financial derivatives (loss) gain	**—**	**—**	**(4.07)**	—	—	0.44
Operating netback after financial derivatives	**$ 25.94**	**$ 38.03**	**$ 27.32**	$ 12.08	$ 23.53	$ 18.27

	Nine Months Ended September 30					
	2018			2017		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**37,629**	**36,617**	**74,246**	34,025	36,448	70,473
Operating netback:						
Total sales, net of blending and other expense	**$ 40.56**	**$ 59.89**	**$ 50.09**	$ 33.37	$ 44.64	$ 39.20
Less:						
Royalties	**5.40**	**17.86**	**11.54**	4.49	13.13	8.96
Operating expense	**14.31**	**6.67**	**10.54**	14.31	6.69	10.37
Transportation expense	**2.52**	**—**	**1.28**	2.83	—	1.37
Operating netback	**$ 18.33**	**$ 35.36**	**$ 26.73**	$ 11.74	$ 24.82	$ 18.50
Realized financial derivatives (loss) gain	**—**	**—**	**(3.46)**	—	—	0.30
Operating netback after financial derivatives	**$ 18.33**	**$ 35.36**	**$ 23.27**	$ 11.74	$ 24.82	$ 18.80

Operating netback after financial derivatives of $27.32/boe for Q3/2018 and $23.27/boe for YTD 2018 increased 50% from $18.27/boe for Q3/2017 and 24% from $18.80/boe for YTD 2017. The increase in our realized sales price per boe during Q3/2018 and YTD 2018 resulting from higher oil prices was partially offset by higher royalties and slightly higher operating expenses compared the to same periods of 2017. The increase in royalty expense per boe is primarily due to higher realized prices in Q3/2018 and YTD 2018. Operating expense per boe was slightly higher in Q3/2018 and YTD 2018 due to a higher proportion of our production coming from Canada which has higher costs than the U.S. We recorded realized losses on financial derivatives of $4.07/boe in Q3/2018 and $3.46/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 $0.5 million for Q3/2018 and $3.9 million for YTD 2018 compared to $0.5 million for Q3/2017 and $5.5 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 nine months ended September 30, 2018 and 2017.

	Three Months Ended September 30					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation[(1)]	**$ 77,671**	**$ 66,830**	**$ 144,501**	$ 51,635	$ 66,035	$ 117,670
Depletion and depreciation per boe	**$ 18.67**	**$ 19.53**	**$ 19.06**	$ 16.24	$ 20.66	$ 18.45

	Nine Months Ended September 30					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation[(1)]	**$ 172,442**	**$ 192,212**	**$ 364,654**	$ 155,153	$ 216,003	$ 371,156
Depletion and depreciation per boe	**$ 16.79**	**$ 19.23**	**$ 17.99**	$ 16.70	$ 21.71	$ 19.29

(1) Canada includes corporate depreciation.

Depletion and depreciation expense was $144.5 million ($19.06/boe) for Q3/2018 and $364.7 million ($17.99/boe) for YTD 2018 compared to $117.7 million ($18.45/boe) for Q3/2017 and $371.2 million ($19.29/boe) for YTD 2017. In Canada, the depletion rate for YTD 2018 was consistent with YTD 2017. Total depletion expense and the depletion rate in Canada increased in Q3/2018 following closing of the Strategic Combination as the depletion rate on our Viking properties is higher than our other Canadian properties. The U.S. depletion rate for 2018 is lower than 2017 primarily due to 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 nine months ended September 30, 2018 and 2017.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands except for per boe)	**2018**	2017	Change	**2018**	2017	Change
General and administrative expense	**$ 10,158**	$ 11,074	$ (916)	**$ 31,729**	$ 37,672	$ (5,943)
General and administrative expense per boe	**$ 1.34**	$ 1.74	$ (0.40)	**$ 1.57**	$ 1.96	$ (0.39)

G&A expense of $31.7 million ($1.57/boe) for YTD 2018 is consistent with our expectation. Our annual guidance of approximately $45 million ($1.55/boe) includes additional G&A in Q4/2018 from higher staffing and additional costs associated with the Strategic Combination.

We reported G&A expense of $10.2 million ($1.34/boe) for Q3/2018 and $31.7 million ($1.57/boe) for YTD 2018 compared to $11.1 million ($1.74/boe) for Q3/2017 and $37.7 million ($1.96/boe) for YTD 2017. G&A expense was lower in Q3/2018 as the impact of higher staffing levels following closing of the Strategic Combination was more than offset by an increase in recoveries associated with a more active capital program in Canada during Q3/2018 relative to Q3/2017. The decrease in G&A expense for YTD 2018 compared to YTD 2017 reflects lower personnel costs following a reduction in staffing levels in Q2/2017 along with higher recoveries associated with higher capital activity in Canada relative to YTD 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 $7.2 million for Q3/2018 and $15.0 million for YTD 2018 compared to $2.5 million for Q3/2017 and $12.6 million for YTD 2017. Q3/2018 SBC expense increased approximately $2.6 million as a result of the Strategic Combination. SBC expense is higher in YTD 2018 due to a higher value of share awards granted in YTD 2018 compared to YTD 2017 and additional expense recorded in Q3/2018 related to the Strategic Combination.

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 the discount rates used to present value these obligations.

Financing and interest expense was $30.0 million for Q3/2018 and $86.8 million for YTD 2018 compared to $27.5 million reported for Q2/2017 and $85.3 million for YTD 2017. Cash interest on long-term notes of $66.1 million for YTD 2018 was slightly lower than $67.1 million for the same period of 2017 as a result of a stronger Canadian dollar during YTD 2018 which reduced the reported amount of U.S. dollar interest in Canadian dollars. The increase in cash interest on our bank loan in YTD 2018 compared to YTD 2017 is a result of higher levels of bank debt outstanding during YTD 2018 due to the assumption of $316.8 million of outstanding debt as part of the Strategic Combination. Cash interest of $76.4 million ($3.77/boe) for the first nine months of 2018 is consistent with our full year guidance of approximately $104 million and $3.58/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 September 30			Nine Months Ended September 30		
($ thousands except for exchange rates)	**2018**	2017	Change	**2018**	2017	Change
Unrealized foreign exchange loss (gain)	**$ (20,583)**	$ (44,006)	$ 23,423	**$ 38,136**	$ (87,389)	$ 125,525
Realized foreign exchange loss (gain)	**(360)**	1,531	(1,891)	**1,887**	1,373	514
Foreign exchange loss (gain)	**$ (20,943)**	$ (42,475)	$ 21,532	**$ 40,023**	$ (86,016)	$ 126,039
CAD/USD exchange rates:						
At beginning of period	**1.3142**	1.2983		**1.2518**	1.3427	
At end of period	**1.2924**	1.2510		**1.2924**	1.2510	

We recorded an unrealized foreign exchange gain of $20.6 million for Q3/2018 and a loss of $38.1 million for YTD 2018 as the Canadian dollar strengthened relative to the U.S. dollar during Q3/2018 and weakened relative to the U.S. dollar during YTD 2018. The CAD/USD exchange rate was 1.2924 as at September 30, 2018 compared to 1.3142 as at June 30, 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 $1.9 million for the first nine months of 2018 compared to a loss of $1.4 million for the same period of 2017.

Income Taxes

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2018**	2017	Change	**2018**	2017	Change
Current income tax expense (recovery)	**$ —**	$ (48)	$ 48	**$ (71)**	$ (1,489)	$ 1,418
Deferred income tax expense (recovery)	**(4,427)**	(18,486)	14,059	**(51,905)**	(54,226)	2,321
Total income tax recovery	**$ (4,427)**	$ (18,534)	$ 14,107	**$ (51,976)**	$ (55,715)	$ 3,739

Current income taxes were nominal for the three and nine months ended September 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 $4.4 million for Q3/2018 and $51.9 million for YTD 2018 compared to $18.5 million for Q3/2017 and $54.2 million for YTD 2017. The decrease in the deferred income tax recovery in 2018 compared to 2017 is primarily the result of higher adjusted funds flow in the U.S. which resulted in greater use of available tax pool shelter. During YTD 2018, we recorded unrealized losses on financial derivatives which offset the impact of higher adjusted funds flow relative to YTD 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 nine months ended September 30, 2018 and 2017 are set forth in the following table.

	Three Months Ended September 30			Nine Months Ended September 30		
($ thousands)	**2018**	2017	Change	**2018**	2017	Change
Petroleum and natural gas sales	**$ 436,761**	$ 258,620	$ 178,141	**$ 1,070,433**	$ 796,706	$ 273,727
Royalties	**(91,945)**	(55,176)	(36,769)	**(233,989)**	(172,367)	(61,622)
Revenue, net of royalties	**344,816**	203,444	141,372	**836,444**	624,339	212,105
Expenses						
Operating	**(77,698)**	(64,391)	(13,307)	**(213,735)**	(199,446)	(14,289)
Transportation	**(9,520)**	(9,312)	(208)	**(25,875)**	(26,327)	452
Blending and other	**(19,548)**	(16,069)	(3,479)	**(55,077)**	(42,554)	(12,523)
Operating netback	**$ 238,050**	$ 113,672	$ 124,378	**$ 541,757**	$ 356,012	$ 185,745
General and administrative	**(10,158)**	(11,074)	916	**(31,729)**	(37,672)	5,943
Cash financing and interest	**(26,343)**	(24,526)	(1,817)	**(76,384)**	(75,632)	(752)
Realized financial derivatives (loss) gain	**(30,854)**	2,795	(33,649)	**(70,103)**	5,719	(75,822)
Realized foreign exchange gain (loss)	**360**	(1,531)	1,891	**(1,887)**	(1,373)	(514)
Other income (expense)	**302**	(283)	585	**869**	(1,192)	2,061
Current income tax recovery (expense)	**—**	48	(48)	**71**	1,489	(1,418)
Payments on onerous contracts	**(147)**	(1,761)	1,614	**(439)**	(5,506)	5,067
Adjusted funds flow	**$ 171,210**	$ 77,340	$ 93,870	**$ 362,155**	$ 241,845	$ 120,310
Acquisition costs	**(13,066)**	—	(13,066)	**(13,066)**	—	(13,066)
Exploration and evaluation	**(510)**	(497)	(13)	**(3,887)**	(5,505)	1,618
Depletion and depreciation	**(144,501)**	(117,670)	(26,831)	**(364,654)**	(371,156)	6,502
Share based compensation	**(7,180)**	(2,469)	(4,711)	**(15,010)**	(12,611)	(2,399)
Non-cash financing and accretion	**(3,686)**	(2,972)	(714)	**(10,441)**	(9,664)	(777)
Unrealized financial derivatives (loss) gain	**(46)**	(21,145)	21,099	**(65,140)**	27,698	(92,838)
Unrealized foreign exchange gain (loss)	**20,583**	44,006	(23,423)	**(38,136)**	87,389	(125,525)
Gain (loss) on disposition of oil and gas properties	**34**	(6,068)	6,102	**1,764**	(6,592)	8,356
Deferred income tax recovery (expense)	**4,427**	18,486	(14,059)	**51,905**	54,226	(2,321)
Payments on onerous contracts	**147**	1,761	(1,614)	**439**	5,506	(5,067)
Net income (loss) for the period	**$ 27,412**	$ (9,228)	$ 36,640	**$ (94,071)**	$ 11,136	$ (105,207)

We generated adjusted funds flow of $171.2 million for Q3/2018, an increase of $93.9 million from adjusted funds flow of $77.3 million reported for Q3/2017. The increase in adjusted funds flow in the third quarter of 2018 was primarily due to a higher operating netback which increased by $124.4 million from the same period in 2017. The increase in operating netback was due to higher commodity prices and average daily production from the Strategic Combination which increased revenues. This was partially offset by higher royalties in Q3/2018 as compared to Q3/2017 along with a $33.6 million increase in realized hedging losses.

In Q3/2018, we recorded net income of $27.4 million compared to a net loss of $9.2 million for the same period of 2017. The increase in net income was driven by the $93.9 million increase in adjusted funds flow. This was offset by higher depletion of $26.8 million and $13.1 million of acquisition costs from the Strategic Combination and a lower deferred tax recovery in Q3/2018.

Adjusted funds flow of $362.2 million for YTD 2018 was $120.3 million higher than $241.8 million for YTD 2017. The increase in adjusted funds flow for YTD 2018 was driven by higher commodity prices and average daily production which resulted in a $212.1 million increase in revenue, net of royalties as compared to YTD 2017. Operating netback for YTD 2018 was $185.7 million higher than YTD 2017 as the increase in revenue, net of royalties, was partially offset by a $12.5 million increase in blending and other expense along with an increase in operating expenses associated with the Strategic Combination. We recorded realized financial derivative losses of $70.1 million in YTD 2018 as compared to gains of $5.7 million for YTD 2017 which offset the increase in operating netbacks by $75.8 million.

We recorded a net loss of $94.1 million for YTD 2018 as compared to net income of $11.1 million reported for the same period of 2017. The change in net income was primarily a result of strengthening commodity prices which increased our adjusted funds flow by $120.3 million but also increased our unrealized loss on financial derivatives for YTD 2018 by $92.8 million as we recorded a loss of $65.1 million in YTD 2018 compared to a $27.7 million gain for YTD 2017. We also recorded an unrealized foreign exchange loss of $38.1 million related to the weakening of the Canadian dollar during YTD 2018 which impacted the carrying value of our long-term notes. This resulted in a $125.5 million change in net income compared to YTD 2017 when we recorded an unrealized foreign exchange gain of $87.4 million. These factors combined to more than offset the increase in adjusted funds flow and resulted in a $105.2 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 $77.1 million foreign currency translation gain for the nine months ended September 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 1.2924 as at September 30, 2018 compared to 1.2518 as at December 31, 2017.

Capital Expenditures

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

	Three Months Ended September 30					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land and seismic	**$ 1,364**	**$ —**	**$ 1,364**	$ 664	$ 1,143	$ 1,807
Drilling, completion and equipping	**80,244**	**42,352**	**122,596**	7,921	44,563	52,484
Facilities	**14,106**	**2,204**	**16,310**	5,902	1,351	7,253
Other	**(1,237)**	**162**	**(1,075)**	—	—	—
Total exploration and development	**$ 94,477**	**$ 44,718**	**$ 139,195**	$ 14,487	$ 47,057	$ 61,544
Total acquisitions, net of proceeds from divestitures	**46**	**—**	**46**	(7,436)	—	(7,436)
Total oil and natural gas expenditures	**$ 94,523**	**$ 44,718**	**$ 139,241**	$ 7,051	$ 47,057	$ 54,108

	Nine Months Ended September 30					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land and seismic	**$ 4,699**	**$ —**	**$ 4,699**	$ 3,475	$ 1,143	$ 4,618
Drilling, completion and equipping	**122,980**	**123,468**	**246,448**	56,032	154,623	210,655
Facilities	**46,474**	**11,217**	**57,691**	11,901	8,936	20,837
Other	**2,457**	**264**	**2,721**	—	—	—
Total exploration and development	**$ 176,610**	**$ 134,949**	**$ 311,559**	$ 71,408	$ 164,702	$ 236,110
Total acquisitions, net of proceeds from divestitures	**(2,001)**	**—**	**(2,001)**	63,794	—	63,794
Total oil and natural gas expenditures	**$ 174,609**	**$ 134,949**	**$ 309,558**	$ 135,202	$ 164,702	$ 299,904

Exploration and development expenditures were $139.2 million for Q3/2018 and $311.6 million for YTD 2018 compared to $61.5 million for Q3/2017 and $236.1 million for YTD 2017. Our Q3/2018 and YTD 2018 capital program includes $40.4 million of exploration and development expenditures for our Viking and Duvernay light oil properties subsequent to closing of the Strategic Combination.

Total exploration and development expenditures in Canada were $94.5 million in Q3/2018 compared to $14.5 million in Q3/2017. We drilled 87 (66.8 net) wells and spent $80.2 million on drilling, completion and equipping costs during Q3/2018 compared to drilling 20 (7.4 net) wells during Q3/2017 for $7.9 million. YTD 2018 drilling, completion and equipping costs of $123.0 million were $66.9 million higher than $56.0 million for YTD 2017 primarily due to $40.4 million invested on light oil exploration and development at our Viking and Duvernay properties during Q3/2018. During YTD 2018 we invested $46.5 million on facilities in Canada including construction of a gas plant and strategic infrastructure projects which is up $34.6 million from $11.9 million during the YTD 2017.

In the U.S., exploration and development expenditures for Q3/2018 and YTD 2018 were $44.7 million and $134.9 million respectively, both lower than the $47.1 million and $164.7 million for the comparative periods in 2017. We participated in the drilling of 29 (8.0 net) wells and initiated production from 26 (4.9 net) wells during Q3/2018 compared to 30 (7.9 net) wells drilled and 22 (5.8 net) wells on production in Q3/2017. Lower drilling and completion activity on our lands in YTD 2018 resulted in lower total exploration and development expenditures relative to YTD 2017. We drilled 72 (17.5 net) wells and initiated production from 85 (18.0 net) wells during

YTD 2018 as compared to 104 (25.7 net) wells drilled and 90 (23.3 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 property acquisition and disposition activity in YTD 2018 for net proceeds of $2.0 million compared to YTD 2017 when our property acquisition and disposition activities were primarily comprised of the Peace River property 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 September 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 September 30, 2018, net debt was $2,112.1 million, an increase of $377.8 million from $1,734.3 million at December 31, 2017. The increase in net debt is primarily due to $363.6 million of net debt assumed in conjunction with the Strategic Combination on August 22, 2018.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio calculated on a twelve month trailing basis. At September 30, 2018, our net debt to adjusted funds flow ratio was 2.6, after adjustment for the Strategic Combination as if the transaction had occurred on the first day of the relevant period, compared to a ratio of 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 commodity prices combined with the increase in average daily production. The effect of higher adjusted funds flow more than offset the impact of the increase in net debt as at September 30, 2018 which was primarily due to $363.6 million of net debt assumed in conjunction with the Strategic Combination.

Bank Loan

At September 30, 2018, the principal amount of bank loan outstanding was $490.6 million and we had approximately $552.6 million of undrawn capacity under our credit facilities that total approximately $1.04 billion. Our facilities include US$575 of revolving credit facilities (the "Revolving Facilities") and a CAD$300 million non-revolving term loan (the "Term Loan").

On August 22, 2018, Baytex amended its credit facilities to facilitate the Strategic Combination and the debt assumed from Raging River. The Revolving Facilities are secured and are comprised of a US$35 million operating loan, a US$340 million syndicated revolving loan for Baytex and a US$200 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. and matures on June 4, 2020. The Term Loan is secured by the assets of Baytex's wholly-owned subsidiary, Baytex Energy Limited Partnership and matures on June 4, 2020.

The credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The credit facilities contain standard commercial covenants in addition to the financial covenants detailed below. There are no mandatory principal payments required prior to maturity on June 4, 2020 which could be extended upon our request. Advances (including letters of credit) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank’s prime lending rate, bankers’ acceptance discount rates or London Interbank Offered Rates, plus applicable margins. In the event that Baytex exceeds any of the covenants under the credit facilities, Baytex may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to shareholders.

The agreements and associated amending agreements relating to the credit facilities are accessible on the SEDAR website at www.sedar.com (filed under the category "Material contracts" on April 13, 2016, May 2, 2018, and October 12, 2018**)**.

The weighted average interest rate on the credit facilities for Q3/2018 was 4.1% as compared to 4.0% for Q3/2017.

Financial Covenants

The following table summarizes the financial covenants applicable to the Revolving Facilities and our compliance therewith at September 30, 2018.

Covenant Description	Position as at September 30, 2018	Covenant
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	**0.55:1.00**	3.50:1.00
Interest Coverage[3] (Minimum Ratio)	**9.00:1.00**	2.00:1.00

(1) Senior Secured Debt is defined as the principal amount of the bank loan and $15.0 million of letters of credit identified as other secured obligations in the credit agreements. As at September 30, 2018, the Company's Senior Secured Debt totaled $505.6 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, non-recurring losses, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended September 30, 2018 was $911.1 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended September 30, 2018 were $101.2 million.

Long-Term Notes

We have four series of long-term notes outstanding that total $1.53 billion as at September 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 2.50:1.00. As at September 30, 2018, the fixed charge coverage ratio was 9.00:1.00.

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 will be redeemable at our option, in whole or in part, commencing on June 1, 2019 at specified redemption prices.

Shareholders’ Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the nine months ended September 30, 2018, we issued 3.2 million common shares pursuant to our share-based compensation program and 315.3 million common shares on closing of the Strategic Combination. As at November 1, 2018, we had 554.0 million common shares issued and outstanding and no preferred shares issued and outstanding.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact our adjusted funds flow in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of September 30, 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	**$ 317,118**	$ 317,118	$ —	$ —	$ —
Bank loan[(1) (2)]	**490,565**	—	490,565	—	—
Long-term notes[(2)]	**1,527,733**	—	710,793	300,000	516,940
Interest on long-term notes[(3)]	**342,401**	88,531	160,322	74,110	19,438
Operating leases	**24,697**	7,758	12,628	4,286	25
Processing agreements	**51,340**	11,983	16,947	9,090	13,320
Transportation agreements	**118,590**	13,861	43,359	21,933	39,437
Total	**$ 2,872,444**	$ 439,251	$ 1,434,614	$ 409,419	$ 589,160

(1) The bank loan matures on June 4, 2020 unless maturity is extended at our request.
(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)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Petroleum and natural gas sales	**436,761**	347,605	286,067	303,163	258,620	277,536	260,549	233,116
Net income (loss)	**27,412**	(58,761)	(62,722)	76,038	(9,228)	9,268	11,096	(359,424)
Per common share - basic	**0.07**	(0.25)	(0.27)	0.32	(0.04)	0.04	0.05	(1.66)
Per common share - diluted	**0.07**	(0.25)	(0.27)	0.32	(0.04)	0.04	0.05	(1.66)
Adjusted funds flow	**171,210**	106,690	84,255	105,796	77,340	83,136	81,369	77,239
Per common share - basic	**0.46**	0.45	0.36	0.45	0.33	0.35	0.35	0.36
Per common share - diluted	**0.45**	0.45	0.36	0.44	0.33	0.35	0.34	0.36
Exploration and development	**139,195**	78,830	93,534	90,156	61,544	78,007	96,559	68,029
Canada	**94,477**	30,608	51,525	41,864	14,487	18,439	38,484	12,151
U.S.	**44,718**	48,222	42,009	48,292	47,057	59,568	58,075	55,878
Acquisitions, net of divestitures	**46**	(21)	(2,026)	(3,937)	(7,436)	5,226	66,004	(322)
Net debt	**2,112,090**	1,784,835	1,783,379	1,734,284	1,748,805	1,819,387	1,850,909	1,773,541
Total assets	**6,491,303**	4,476,906	4,433,074	4,372,111	4,353,637	4,582,049	4,702,423	4,594,085
Common shares outstanding	**553,950**	236,662	236,578	235,451	235,451	234,204	234,203	233,449
Daily production								
Total production (boe/d)	**82,412**	70,664	69,522	69,556	69,310	72,812	69,298	65,136
Canada (boe/d)	**45,214**	34,042	33,505	32,194	34,560	34,284	33,217	31,704
U.S. (boe/d)	**37,198**	36,622	36,017	37,362	34,750	38,528	36,081	33,432
Benchmark prices								
WTI oil (US$/bbl)	**69.50**	67.88	62.87	55.40	48.20	48.28	51.91	49.29
WCS heavy (US$/bbl)	**47.25**	48.61	38.59	43.14	38.26	37.16	37.34	34.97
CAD/USD avg exchange rate	**1.3070**	1.2911	1.2651	1.2717	1.2524	1.3447	1.3229	1.3339
AECO gas ($/mcf)	**1.35**	1.03	1.85	1.96	2.04	2.77	2.94	2.81
NYMEX gas (US$/mmbtu)	**2.90**	2.80	3.00	2.93	3.00	3.18	3.32	2.98
Sales price ($/boe)	**55.03**	51.22	42.96	44.75	38.04	39.41	40.16	38.16
Royalties ($/boe)	**12.13**	12.01	10.36	10.86	8.65	9.06	9.17	9.28
Operating expense ($/boe)	**10.25**	10.91	10.53	10.91	10.10	10.70	10.28	9.96
Transportation expense ($/boe)	**1.26**	1.22	1.36	1.20	1.46	1.35	1.29	1.30
Operating netback ($/boe)	**31.39**	27.08	20.71	21.78	17.83	18.30	19.42	17.62
Financial derivatives (loss) gain ($/boe)	**(4.07)**	(4.57)	(1.57)	0.30	0.44	0.40	0.04	1.62
Operating netback after financial derivatives ($/boe)	**27.32**	22.51	19.14	22.08	18.27	18.70	19.46	19.24

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$49.29/bbl in Q4/2016 to US$69.50/bbl during Q3/2018. Improved well productivity from enhanced completion techniques contributed to the increase in daily production in the U.S. with a reduction in quarterly exploration and development expenditures. 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 along with the Strategic Combination in Q3/2018 has increased production from Q4/2016 into Q3/2018. 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 increased from $1,773.5 million at Q4/2016 to $2,112.1 million at Q3/2018 primarily due to the additional net debt assumed in conjunction with the Strategic Combination in Q3/2018.

2018 GUIDANCE

The following table compares our 2018 annual guidance to our YTD 2018 results.

	Original Guidance (1)	Current Guidance (2)	YTD 2018
Exploration and development capital	$450 - $500 million	$450 - $500 million	$311.6 million
Production (boe/d)	79,000 to 81,000	79,000 to 80,000	74,246
Expenses:			
Royalty rate	~ 21.0%	~ 22.0%	23.0%
Operating	$10.75 - $11.25/boe	$10.50 - $10.75/boe	$10.54/boe
Transportation	$1.35 - $1.45/boe	$1.25 - $1.30/boe	$1.28/boe
General and administrative	~ $48 million ($1.64/boe)	~ $45 million ($1.55/boe)	$31.7 million ($1.57/boe)
Interest	~ $105 million ($3.60/boe)	~ $104 million ($3.58/boe)	$76.4 million ($3.77/boe)

(1) As announced on August 22, 2018 to include Raging River from the closing date of the Strategic Combination.
(2) Updated as at November 2, 2018.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at September 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 nine months ended September 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 12 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 contractual 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 at 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 provides 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 within our capital budgeting process which considers available adjusted funds flow. In addition, we have removed transaction costs from the Strategic Combination as we consider the costs non-recurring and not reflective of our ongoing ability to generate 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 September 30		Nine Months Ended September 30	
($ thousands)	**2018**	2017	**2018**	2017
Cash flow from operating activities	**$ 154,091**	$ 77,912	**$ 316,241**	$ 228,885
Change in non-cash working capital	**1,025**	(2,326)	**23,633**	3,311
Asset retirement obligations settled	**3,028**	1,754	**9,215**	9,649
Transaction costs	**13,066**	—	**13,066**	—
Adjusted funds flow	**$ 171,210**	$ 77,340	**$ 362,155**	$ 241,845

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)		**September 30, 2018**		December 31, 2017
Bank loan[1]	**$**	**490,565**	$	213,376
Long-term notes[1]		**1,527,733**		1,489,210
Working capital (surplus) deficiency[2]		**93,792**		31,698
Net debt	**$**	**2,112,090**	$	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 September 30				Nine Months Ended September 30			
($ thousands)		**2018**		2017		**2018**		2017
Petroleum and natural gas sales	**$**	**436,761**	$	258,620	**$**	**1,070,433**	$	796,706
Blending and other expense		**(19,548)**		(16,069)		**(55,077)**		(42,554)
Total sales, net of blending and other expense		**417,213**		242,551		**1,015,356**		754,152
Less:								
Royalties		**91,945**		55,176		**233,989**		172,367
Operating expense		**77,698**		64,391		**213,735**		199,446
Transportation expense		**9,520**		9,312		**25,875**		26,327
Operating netback		**238,050**		113,672		**541,757**		356,012
Realized financial derivative gain (loss)		**(30,854)**		2,795		**(70,103)**		5,719
Operating netback after realized financial derivatives gain (loss)	**$**	**207,196**	$	116,467	**$**	**471,654**	$	361,731

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 September 30		Nine Months Ended September 30	
($ thousands)	**2018**	2017	**2018**	2017
Net income (loss)	**$ 27,412**	$ (9,228)	**$ (94,071)**	$ 11,136
Plus:				
Financing and interest	**30,029**	27,498	**86,825**	85,296
Unrealized foreign exchange (gain) loss	**(20,583)**	(44,006)	**38,136**	(87,389)
Unrealized financial derivatives (gain) loss	**46**	21,145	**65,140**	(27,698)
Current income tax expense (recovery)	**—**	(48)	**(71)**	(1,489)
Deferred income tax recovery	**(4,427)**	(18,486)	**(51,905)**	(54,226)
Depletion and depreciation	**144,501**	117,670	**364,654**	371,156
(Gain) loss on disposition of oil and gas properties	**(34)**	6,068	**(1,764)**	6,592
Transaction costs	**13,066**	—	**13,066**	—
Non-cash items[1]	**7,690**	2,966	**18,897**	18,116
Strategic combination adjustment [2]	**96,736**	—	**255,800**	—
Bank EBITDA	**$ 294,436**	**$ 103,579**	**$ 694,707**	**$ 321,494**

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

INTERNAL CONTROL OVER FINANCIAL REPORTING

We are required to comply with Multilateral Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings". This instrument requires us to disclose in our interim MD&A any weaknesses in or changes to our internal control over financial reporting during the period that may have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting. We confirm that no such weaknesses were identified in, or changes were made to, internal controls over financial reporting during the three months ended September 30, 2018, except for the matter described below.

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

During the three months ended September 30, 2018, the assets previously held by Raging River contributed revenues net of royalties of $60.6 million (representing 18% of total revenues, net of royalties) and operating income (revenues, net of royalties, less operating, transportation and blending and other expenses) of $48.0 million (representing 20% of total operating income). At September 30, 2018, current assets of $58.2 million, non-current assets of $2.0 billion, current liabilities of $148.7 million and non-current liabilities of $673.3 million were associated with acquired entity.

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our corporate royalty rate for 2018; the existence, operation and strategy of our risk management program; 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 internally generated adjusted funds flow and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures; that a significant portion of our financial obligations will be funded by adjusted funds flow; our capital budget and expected average daily production for 2018; 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	September 30, 2018	December 31, 2017
ASSETS		
Current assets		
Cash	$ 45,159	$ —
Trade and other receivables	178,167	112,844
Financial derivatives (note 18)	5,725	18,510
	229,051	131,354
Non-current assets		
Financial derivatives (note 18)	489	—
Exploration and evaluation assets (note 6)	365,235	272,974
Oil and gas properties (note 7)	5,887,126	3,958,309
Other plant and equipment	9,402	9,474
	$ 6,491,303	$ 4,372,111
LIABILITIES		
Current liabilities		
Trade and other payables	$ 317,118	$ 144,542
Financial derivatives (note 18)	98,522	50,095
Onerous contracts	2,135	2,574
	417,775	197,211
Non-current liabilities		
Bank loan (note 8)	488,804	212,138
Long-term notes (note 9)	1,514,459	1,474,184
Asset retirement obligations (note 10)	553,624	368,995
Deferred income tax liability	351,977	204,698
Financial derivatives (note 18)	9,965	—
	3,336,604	2,457,226
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 11)	5,701,527	4,443,576
Contributed surplus	14,837	15,999
Accumulated other comprehensive income	540,200	463,104
Deficit	(3,101,865)	(3,007,794)
	3,154,699	1,914,885
	$ 6,491,303	$ 4,372,111

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 September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Revenue, net of royalties				
Petroleum and natural gas sales (note 12)	**$ 436,761**	$ 258,620	**$ 1,070,433**	$ 796,706
Royalties	**(91,945)**	(55,176)	**(233,989)**	(172,367)
	344,816	203,444	**836,444**	624,339
Expenses				
Operating	**77,698**	64,391	**213,735**	199,446
Transportation	**9,520**	9,312	**25,875**	26,327
Blending and other	**19,548**	16,069	**55,077**	42,554
General and administrative	**10,158**	11,074	**31,729**	37,672
Transaction costs (note 4)	**13,066**	—	**13,066**	—
Exploration and evaluation (note 6)	**510**	497	**3,887**	5,505
Depletion and depreciation	**144,501**	117,670	**364,654**	371,156
Share-based compensation (note 13)	**7,180**	2,469	**15,010**	12,611
Financing and interest (note 16)	**30,029**	27,498	**86,825**	85,296
Financial derivatives loss (gain) (note 18)	**30,900**	18,350	**135,243**	(33,417)
Foreign exchange loss (gain) (note 17)	**(20,943)**	(42,475)	**40,023**	(86,016)
(Gain) loss on disposition of oil and gas properties	**(34)**	6,068	**(1,764)**	6,592
Other (income) expense	**(302)**	283	**(869)**	1,192
	321,831	231,206	**982,491**	668,918
Net income (loss) before income taxes	**22,985**	(27,762)	**(146,047)**	(44,579)
Income tax expense (recovery) (note 15)				
Current income tax expense (recovery)	**—**	(48)	**(71)**	(1,489)
Deferred income tax expense (recovery)	**(4,427)**	(18,486)	**(51,905)**	(54,226)
	(4,427)	(18,534)	**(51,976)**	(55,715)
Net income (loss) attributable to shareholders	**$ 27,412**	$ (9,228)	**$ (94,071)**	$ 11,136
Other comprehensive income (loss)				
Foreign currency translation adjustment	**(39,360)**	(85,483)	**77,096**	(165,809)
Comprehensive income (loss)	**$ (11,948)**	$ (94,711)	**$ (16,975)**	$ (154,673)
Net income (loss) per common share (note 14)				
Basic	**$ 0.07**	$ (0.04)	**$ (0.33)**	$ 0.05
Diluted	**$ 0.07**	$ (0.04)	**$ (0.33)**	$ 0.05
Weighted average common shares (note 14)				
Basic	**375,435**	235,451	**283,302**	234,563
Diluted	**378,763**	235,451	**283,302**	237,203

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	20,914	(20,914)	—	—	**—**
Share-based compensation	—	12,611	—	—	**12,611**
Comprehensive income (loss) for the period	—	—	(165,809)	11,136	**(154,673)**
Balance at September 30, 2017	$ 4,443,575	$ 13,102	$ 464,054	$ (3,083,832)	**$ 1,836,899**
Balance at December 31, 2017	$ 4,443,576	$ 15,999	$ 463,104	$ (3,007,794)	**$ 1,914,885**
Issued on corporate acquisition (note 4)	1,238,995	3,100	—	—	**1,242,095**
Issuance costs, net of tax (notes 4 and 11)	(316)	—	—	—	**(316)**
Vesting of share awards	19,272	(19,272)	—	—	**—**
Share-based compensation	—	15,010	—	—	**15,010**
Comprehensive income (loss) for the period	—	—	77,096	(94,071)	**(16,975)**
Balance at September 30, 2018	$ 5,701,527	$ 14,837	$ 540,200	$ (3,101,865)	**$ 3,154,699**

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

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income (loss) for the period	**$ 27,412**	$ (9,228)	**$ (94,071)**	$ 11,136
Adjustments for:				
Share-based compensation (note 13)	**7,180**	2,469	**15,010**	12,611
Unrealized foreign exchange loss (gain) (note 17)	**(20,583)**	(44,006)	**38,136**	(87,389)
Exploration and evaluation (note 6)	**510**	497	**3,887**	5,505
Depletion and depreciation	**144,501**	117,670	**364,654**	371,156
Non-cash financing and accretion (note 16)	**3,686**	2,972	**10,441**	9,664
Unrealized financial derivatives loss (gain) (note 18)	**46**	21,145	**65,140**	(27,698)
(Gain) loss on disposition of capital properties	**(34)**	6,068	**(1,764)**	6,592
Deferred income tax recovery	**(4,427)**	(18,486)	**(51,905)**	(54,226)
Payments on onerous contracts	**(147)**	(1,761)	**(439)**	(5,506)
Asset retirement obligations settled (note 10)	**(3,028)**	(1,754)	**(9,215)**	(9,649)
Change in non-cash working capital	**(1,025)**	2,326	**(23,633)**	(3,311)
	154,091	77,912	**316,241**	228,885
Financing activities				
Increase (decrease) in bank loan	**(38,305)**	(33,153)	**(43,348)**	46,328
Common share issuance costs (notes 4 and 11)	**(433)**	—	**(433)**	—
Redemption of long-term notes	**—**	(8,580)	**—**	(8,580)
	(38,738)	(41,733)	**(43,781)**	37,748
Investing activities				
Additions to exploration and evaluation assets (note 6)	**(2,462)**	(507)	**(3,864)**	(5,344)
Additions to oil and gas properties (note 7)	**(136,733)**	(61,037)	**(307,695)**	(230,766)
Additions to other plant and equipment	**(1,395)**	108	**(1,902)**	(510)
Property acquisitions	**—**	—	**(187)**	(71,610)
Proceeds from disposition of capital properties (notes 6 & 7)	**—**	7,436	**2,234**	7,816
Change in non-cash working capital	**70,396**	16,000	**84,113**	31,624
	(70,194)	(38,000)	**(227,301)**	(268,790)
Change in cash	**45,159**	(1,821)	**45,159**	(2,157)
Cash, beginning of period	**—**	2,369	**—**	2,705
Cash, end of period	**$ 45,159**	$ 548	**$ 45,159**	$ 548
Supplementary information				
Interest paid	**$ 20,708**	$ 21,973	**$ 70,406**	$ 72,167
Income taxes paid (recovered)	**$ 10**	$ —	**$ (71)**	$ 44

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 November 1, 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.

Consolidation

The consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries. Subsidiaries are entities controlled by the Company. Control exists when the Company has the power to govern the financial and operating policies to obtain benefits from its activities. Significant subsidiaries included in the Company's accounts include Baytex Energy USA, Inc., Baytex Energy Ltd., Baytex Energy Limited Partnership, and Baytex Energy Partnership. Intercompany balances and transactions are eliminated in preparation of the consolidated financial statements.

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 12 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 contractual 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 completing its review and analysis of the significant lease contracts that fall into the scope of the new standard and continues to work through scoping and completeness procedures in preparation for adoption on January 1, 2019.

4. BUSINESS COMBINATION

On August 22, 2018, Baytex completed a plan of arrangement whereby Baytex acquired, directly and indirectly, all of the issued and outstanding common shares of Raging River Exploration Inc. ("Raging River"), a publicly traded oil and gas producer with light oil producing properties in southwest Saskatchewan and Alberta. Baytex is treated as the acquirer for accounting purposes. In identifying Baytex as the acquirer, Baytex considered, amongst other things, voting rights of all equity instruments, the intended corporate governance structure and composition of senior management of the combined company, in addition to various metrics used to evaluate the relative size of each company. All factors were considered in arriving at the conclusion that Baytex is the acquirer for accounting purposes. The acquisition increases Baytex's position in southwest Saskatchewan and creates a well-capitalized, oil-weighted company.

The acquisition was accounted for as a business combination whereby the net assets acquired and liabilities assumed were recorded at fair value at the acquisition date. Consideration consisted of the issuance of 315.3 million Baytex common shares valued at approximately $1.2 billion (based on the closing price of Baytex's common shares of $3.93 on the Toronto Stock Exchange on August 22, 2018). The preliminary estimate of fair value of oil and gas properties acquired was determined using internal estimates of proved plus probable reserves. Asset retirement obligations were determined using internal estimates of the timing and estimated costs associated with the abandonment and reclamation of the wells and facilities acquired using a market discount rate of 7.5% percent. The fair value of exploration and evaluation properties was estimated with reference to recent land sales in similar areas.

The total consideration paid and estimates of the fair value of the assets acquired and liabilities assumed as at the date of the acquisition are set forth in the table below. The estimated fair value of exploration and evaluation assets, oil and gas properties, asset retirement obligations, and the deferred income tax liability are preliminary and subject to adjustment pending finalization of the annual reserves evaluation.

Consideration		
Common shares issued	$	1,238,995
Share based compensation (1)		3,100
Total consideration	**$**	**1,242,095**

Fair value of net assets acquired		
Exploration and evaluation assets	$	97,858
Oil and gas properties		1,748,368
Working capital deficiency excluding bank debt and financial derivatives		(46,773)
Financial derivatives		(5,548)
Bank debt (2)		(316,800)
Asset retirement obligations		(39,960)
Deferred income tax liability		(195,050)
Net assets acquired	**$**	**1,242,095**

(1) Following closing of the transaction, holders of units outstanding under Raging River's share based compensation plans are entitled to Baytex common shares rather than Raging River common shares with adjustment to the exercise price or quantity outstanding based on the exchange ratio for the Raging River shares. As a result, the fair value of the vested units was recognized by Baytex as additional consideration (see note 13).

(2) On August 22, 2018, Baytex amended its credit facilities to include the credit facility assumed in conjunction with the acquisition of Raging River and converted outstanding principal amounts to a non-revolving term loan which matures on June 4, 2020 (see note 8).

These consolidated financial statements include the results of operations of Raging River for the period following closing of the transaction on August 22, 2018. For the three months ended September 30, 2018, the acquisition contributed revenues of $67.0 million and net income before tax of $33.9 million. Had the acquisition occurred on January 1, 2018, revenues would have increased by $379.5 million and net income before income taxes would have increased by $82.1 million for the nine months ended September 30, 2018.

Transaction costs of $13.1 million were expensed as incurred and share issuance costs of $0.3 million were recorded in shareholders' capital in the nine months ended September 30, 2018.

5. SEGMENTED FINANCIAL INFORMATION

Baytex's reportable segments are determined based on the geographic location and nature of the underlying operations:

- Canada includes the exploration for, and the development and production of, crude oil and natural gas in Western Canada;
- U.S. includes the exploration for, and the development and production of, crude oil and natural gas in the United States; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Three Months Ended September 30	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 217,805**	$ 122,307	**$ 218,956**	$ 136,313	**$ —**	$ —	**$ 436,761**	$ 258,620
Royalties	**(26,139)**	(14,973)	**(65,806)**	(40,203)	**—**	—	**(91,945)**	(55,176)
	191,666	107,334	**153,150**	96,110	**—**	—	**344,816**	203,444
Expenses								
Operating	**54,710**	43,525	**22,988**	20,866	**—**	—	**77,698**	64,391
Transportation	**9,520**	9,312	**—**	—	**—**	—	**9,520**	9,312
Blending and other	**19,548**	16,069	**—**	—	**—**	—	**19,548**	16,069
General and administrative	**—**	—	**—**	—	**10,158**	11,074	**10,158**	11,074
Transaction costs	**—**	—	**—**	—	**13,066**	—	**13,066**	—
Exploration and evaluation	**510**	497	**—**	—	**—**	—	**510**	497
Depletion and depreciation	**77,671**	51,526	**66,830**	66,035	**—**	109	**144,501**	117,670
Share-based compensation	**—**	—	**—**	—	**7,180**	2,469	**7,180**	2,469
Financing and interest	**—**	—	**—**	—	**30,029**	27,498	**30,029**	27,498
Financial derivatives loss (gain)	**—**	—	**—**	—	**30,900**	18,350	**30,900**	18,350
Foreign exchange loss (gain)	**—**	—	**—**	—	**(20,943)**	(42,475)	**(20,943)**	(42,475)
(Gain) loss on disposition of oil and gas properties	**(34)**	6,068	**—**	—	**—**	—	**(34)**	6,068
Other (income) expense	**—**	—	**—**	—	**(302)**	283	**(302)**	283
	161,925	126,997	**89,818**	86,901	**70,088**	17,308	**321,831**	231,206
Net income (loss) before income taxes	**29,741**	(19,663)	**63,332**	9,209	**(70,088)**	(17,308)	**22,985**	(27,762)
Income tax expense (recovery)								
Current income tax expense (recovery)	**—**	—	**—**	(48)	**—**	—	**—**	(48)
Deferred income tax expense (recovery)	**4,134**	5,402	**9,278**	(8,774)	**(17,839)**	(15,114)	**(4,427)**	(18,486)
	4,134	5,402	**9,278**	(8,822)	**(17,839)**	(15,114)	**(4,427)**	(18,534)
Net income (loss)	**$ 25,607**	$ (25,065)	**$ 54,054**	$ 18,031	**$ (52,249)**	$ (2,194)	**$ 27,412**	$ (9,228)
Total oil and natural gas capital expenditures(1)	**$ 94,523**	$ 7,051	**$ 44,718**	$ 47,057	**$ —**	$ —	**$ 139,241**	$ 54,108

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

Nine Months Ended September 30	Canada 2018	Canada 2017	U.S. 2018	U.S. 2017	Corporate 2018	Corporate 2017	Consolidated 2018	Consolidated 2017
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 471,742**	$ 352,522	**$ 598,691**	$ 444,184	**$ —**	$ —	**$ 1,070,433**	$ 796,706
Royalties	**(55,471)**	(41,725)	**(178,518)**	(130,642)	**—**	—	**(233,989)**	(172,367)
	416,271	310,797	**420,173**	313,542	**—**	—	**836,444**	624,339
Expenses								
Operating	**147,054**	132,908	**66,681**	66,538	**—**	—	**213,735**	199,446
Transportation	**25,875**	26,327	**—**	—	**—**	—	**25,875**	26,327
Blending and other	**55,077**	42,554	**—**	—	**—**	—	**55,077**	42,554
General and administrative	**—**	—	**—**	—	**31,729**	37,672	**31,729**	37,672
Transaction costs	**—**	—	**—**	—	**13,066**	—	**13,066**	—
Exploration and evaluation	**3,887**	5,505	**—**	—	**—**	—	**3,887**	5,505
Depletion and depreciation	**172,442**	153,392	**192,212**	216,003	**—**	1,761	**364,654**	371,156
Share-based compensation	**—**	—	**—**	—	**15,010**	12,611	**15,010**	12,611
Financing and interest	**—**	—	**—**	—	**86,825**	85,296	**86,825**	85,296
Financial derivatives loss (gain)	**—**	—	**—**	—	**135,243**	(33,417)	**135,243**	(33,417)
Foreign exchange loss (gain)	**—**	—	**—**	—	**40,023**	(86,016)	**40,023**	(86,016)
(Gain) loss on disposition of oil and gas properties	**(1,764)**	6,592	**—**	—	**—**	—	**(1,764)**	6,592
Other (income) expense	**—**	—	**—**	—	**(869)**	1,192	**(869)**	1,192
	402,571	367,278	**258,893**	282,541	**321,027**	19,099	**982,491**	668,918
Net income (loss) before income taxes	**13,700**	(56,481)	**161,280**	31,001	**(321,027)**	(19,099)	**(146,047)**	(44,579)
Income tax expense (recovery)								
Current income tax expense (recovery)	**—**	—	**(71)**	(1,489)	**—**	—	**(71)**	(1,489)
Deferred income tax expense (recovery)	**(197)**	(5,372)	**15,951**	(27,336)	**(67,659)**	(21,518)	**(51,905)**	(54,226)
	(197)	(5,372)	**15,880**	(28,825)	**(67,659)**	(21,518)	**(51,976)**	(55,715)
Net income (loss)	**$ 13,897**	$ (51,109)	**$ 145,400**	$ 59,826	**$ (253,368)**	$ 2,419	**$ (94,071)**	$ 11,136
Total oil and natural gas capital expenditures[1]	**$ 174,609**	$ 135,202	**$ 134,949**	$ 164,702	**$ —**	$ —	**$ 309,558**	$ 299,904

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

As at	September 30, 2018	December 31, 2017
Canadian assets	**$ 3,746,034**	$ 1,677,821
U.S. assets	**2,735,867**	2,684,816
Corporate assets	**9,402**	9,474
Total consolidated assets	**$ 6,491,303**	$ 4,372,111

6. EXPLORATION AND EVALUATION ASSETS

	September 30, 2018	December 31, 2017
Balance, beginning of period	**$ 272,974**	$ 308,462
Capital expenditures	**3,864**	7,118
Corporate acquisition (note 4)	**97,858**	—
Divestitures	**(872)**	(1,276)
Exploration and evaluation expense	**(3,887)**	(8,253)
Transfer to oil and gas properties	**(9,895)**	(20,198)
Foreign currency translation	**5,193**	(12,879)
Balance, end of period	**$ 365,235**	$ 272,974

7. 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		307,695		—		307,695
Corporate acquisition (note 4)		1,748,368		—		1,748,368
Property acquisitions		202		—		202
Transferred from exploration and evaluation assets		9,895		—		9,895
Change in asset retirement obligations (note 10)		145,883		—		145,883
Divestitures		(15)		—		(15)
Foreign currency translation		114,808		(35,293)		79,515
Depletion		—		(362,726)		(362,726)
Balance, September 30, 2018	**$**	**10,259,163**	**$**	**(4,372,037)**	**$**	**5,887,126**

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 September 30, 2018.

8. BANK LOAN

		September 30, 2018		December 31, 2017
Bank loan - U.S. dollar denominated (1)	**$**	**175,417**	$	166,489
Bank loan - Canadian dollar denominated		**315,148**		46,887
Bank loan - principal		**490,565**		213,376
Unamortized debt issuance costs		**(1,761)**		(1,238)
Bank loan	**$**	**488,804**	$	212,138

(1) U.S. dollar denominated bank loan balance as at September 30, 2018 was US$136.0 million (US$133.0 million as at December 31, 2017).

Baytex has credit facilities that include US$575 million of revolving credit facilities (the "Revolving Facilities") and a CAD$300 million non-revolving term loan (the "Term Loan"). On April 25, 2018, Baytex amended its credit facilities to extend maturity from June 4, 2019 to June 4, 2020. On August 22, 2018, Baytex amended its credit facilities to include the credit facility assumed in conjunction with the acquisition of Raging River (note 4) and converted outstanding principal amounts to the Term Loan which matures on June 4, 2020.

The amended extendible secured Revolving Facilities are comprised of a US$35 million operating loan (previously US$25 million) and a US$340 million syndicated revolving loan for Baytex (previously US$350 million) and a US$200 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. and matures on June 4, 2020. The Term Loan is secured by the assets of Baytex's wholly-owned subsidiary, Baytex Energy Limited Partnership and matures on June 4, 2020.

The credit facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The credit facilities contain standard commercial covenants in addition to the financial covenants detailed below. There are no mandatory principal payments required prior to maturity on June 4, 2020 which could be extended upon Baytex's request. Advances (including letters of credit) under the credit facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offered Rates, plus applicable margins. In the event that Baytex breaches any of the covenants under the credit facilities, Baytex may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to shareholders.

At September 30, 2018, Baytex had $15.0 million of outstanding letters of credit (December 31, 2017 - $14.6 million) under the credit facilities.

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

Covenant Description	**Position as at September 30, 2018**	**Covenant**
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.55:1.00**	**3.50:1.00**
Interest Coverage(3) (Minimum Ratio)	**9.00:1.00**	**2.00:1.00**

(1) Senior Secured Debt is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at September 30, 2018, the Company's Senior Secured Debt totaled $505.6 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, non-recurring losses, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended September 30, 2018 was $911.1 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended September 30, 2018 were $101.2 million.

9. LONG-TERM NOTES

	September 30, 2018	December 31, 2017
6.75% notes (US$150,000 – principal) due February 17, 2021	**$ 193,853**	$ 187,770
5.125% notes (US$400,000 – principal) due June 1, 2021	**516,940**	500,720
6.625% notes (Cdn$300,000 – principal) due July 19, 2022	**300,000**	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	**516,940**	500,720
Total long-term notes - principal	**1,527,733**	1,489,210
Unamortized debt issuance costs	**(13,274)**	(15,026)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,514,459**	$ 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 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 8) to financing and interest expenses on a trailing twelve month basis) of 2.50:1.00. As at September 30, 2018, the fixed charge coverage ratio was 9.00:1.00.

10. ASSET RETIREMENT OBLIGATIONS

	September 30, 2018	December 31, 2017
Balance, beginning of period	**$ 368,995**	$ 331,517
Liabilities incurred	**6,856**	5,825
Liabilities settled	**(9,215)**	(13,471)
Liabilities assumed from corporate acquisition (note 4)	**39,960**	—
Liabilities acquired from property acquisitions	**132**	22,264
Liabilities divested	**(580)**	(19,940)
Accretion (note 16)	**7,450**	8,682
Change in estimate	**2,193**	(24,028)
Changes in discount rates and inflation rates(1)	**136,834**	61,011
Foreign currency translation	**999**	(2,865)
Balance, end of period	**$ 553,624**	$ 368,995

(1) Change in discount rates and inflation rates includes $136.8 million to revalue the liabilities acquired in the Raging River acquisition (note 4) using the risk-free discount rate. At the date of acquisition, acquired asset retirement obligation liabilities are fair valued using the market rate.

11. 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 September 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	3,233	19,272
Issued on corporate acquisition (note 4)	315,266	1,238,995
Issuance costs, net of tax (note 4)	—	(316)
Balance, September 30, 2018	**553,950**	**$ 5,701,527**

12. 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 18. 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 from its interest in non-operated oil and natural gas properties.

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, when prudent, 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 September 30					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 69,557**	**$ 170,402**	**$ 239,959**	$ 6,024	$ 101,320	$ 107,344
Heavy oil	**139,305**	**—**	**139,305**	107,972	—	107,972
NGL	**4,147**	**30,508**	**34,655**	2,596	18,116	20,712
Natural gas sales	**4,796**	**18,046**	**22,842**	5,715	16,877	22,592
Total petroleum and natural gas sales	**$ 217,805**	**$ 218,956**	**$ 436,761**	$ 122,307	$ 136,313	$ 258,620

	Nine Months Ended September 30					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 79,894**	**$ 476,086**	**$ 555,980**	$ 18,808	$ 335,190	$ 353,998
Heavy oil	**364,957**	**—**	**364,957**	301,663	—	301,663
NGL	**11,595**	**71,480**	**83,075**	8,040	52,395	60,435
Natural gas sales	**15,296**	**51,125**	**66,421**	24,011	56,599	80,610
Total petroleum and natural gas sales	**$ 471,742**	**$ 598,691**	**$ 1,070,433**	$ 352,522	$ 444,184	$ 796,706

Included in accounts receivable at September 30, 2018 is $146.3 million (December 31, 2017 - $91.6 million) of accrued production revenue related to deliveries for periods ended prior to the reporting date.

13. SHARE AWARD INCENTIVE PLAN

The Company recorded compensation expense related to the share awards of $7.2 million and $15.0 million for the three and nine months ended September 30, 2018 ($2.5 million and $12.6 million for the three and nine months ended September 30, 2017).

The weighted average fair value of share awards granted was $4.04 per restricted and performance award for the nine months ended September 30, 2018 and $5.68 per restricted and performance award for the nine months ended September 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	2,793	2,591	5,384
Issued on corporate acquisition(2)	302	257	559
Vested and converted to common shares	(1,604)	(1,629)	(3,233)
Forfeited	(180)	(154)	(334)
Balance, September 30, 2018	**3,339**	**3,318**	**6,657**

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

(2) Following closing of the acquisition of Raging River (note 4), holders of 0.3 million Raging River restricted awards and 0.3 million performance awards are entitled to Baytex common shares rather than Raging River common shares, after adjusting the quantity of awards outstanding based on the exchange ratio. The fair value of the vested awards was included in consideration (note 4).

Share Options

On August 22, 2018, Baytex became the successor to Raging River's 2012 Option Plan and Raging River's 2016 Option Plan (collectively, the "Option Plans"). Although no new grants will be made under the Option Plans following completion of the Arrangement, share options held under the Option Plans in existence at August 22, 2018 were converted to share options to purchase shares in Baytex.

The Company accounts for share options using the fair value method. Under this method, compensation is expensed over the vesting period for the stock options, with a corresponding increase to contributed surplus.

Share options granted under the Option Plans have a maximum term of 3.5 years to expiry. One third of the options granted will vest on each of the first, second, and third anniversaries of the date of grant. At September 30, 2018, 8.7 million share options with a weighted average exercise price of $6.66 were outstanding. The following tables summarize the information about the share options.

(000s, except per common share amounts)	Number of options	Weighted average exercise price
Balance, December 31, 2017	**—**	**$ —**
Granted	—	—
Issued on corporate acquisition	9,187	6.63
Forfeited/Expired	(453)	6.13
Balance, September 30, 2018	**8,734**	**$ 6.66**

Exercise price	Options outstanding				Options exercisable		
	Number outstanding at September 30, 2018 (000s)	Weighted average remaining life (years)		Weighted average exercise price	Number exercisable at September 30, 2018 (000s)		Weighted average exercise price
$5.00 - $6.00	1,044	1.66	$	5.68	459	$	5.77
$6.01 - $7.00	5,728	0.69		6.47	4,430		6.44
$7.01 - $8.00	1,924	0.97		7.72	1,343		7.73
$8.01 - $9.00	38	1.37		8.26	25		8.26
Total	**8,734**	**0.87**	**$**	**6.66**	**6,257**	**$**	**6.67**

14. NET INCOME (LOSS) PER SHARE

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

	Three Months Ended September 30									
	2018					2017				
		Net income	**Weighted average common shares (000s)**		**Net income per share**		Net loss	Weighted average common shares (000s)		Net loss per share
Net income (loss) - basic	**$**	**27,412**	**375,435**	**$**	**0.07**	$	(9,228)	235,451	$	(0.04)
Dilutive effect of share awards		**—**	**3,328**		**—**		—	—		—
Dilutive effect of share options		**—**	**—**		**—**		—	—		—
Net income (loss) - diluted	**$**	**27,412**	**378,763**	**$**	**0.07**	$	(9,228)	235,451	$	(0.04)

	Nine Months Ended September 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	**$**	**(94,071)**	**283,302**	**$**	**(0.33)**	$	11,136	234,563	$	0.05
Dilutive effect of share awards		**—**	**—**		**—**		—	2,640		—
Dilutive effect of share options		**—**	**—**		**—**		—	—		—
Net income (loss) - diluted	**$**	**(94,071)**	**283,302**	**$**	**(0.33)**	$	11,136	237,203	$	0.05

For the three months ended September 30, 2018 no share awards were considered to be anti-dilutive (2017 - 1.6 million). For the nine months ended September 30, 2018, 6.7 million share awards were excluded from the calculation of diluted earnings per share as they were determined to be anti-dilutive. For the three and nine months ended September 30, 2018, 8.7 million share options were excluded from the calculation of diluted earnings per share as they were out of the money.

15. INCOME TAXES

The provision for income taxes has been computed as follows:

	Nine Months Ended September 30	
	2018	2017
Net loss before income taxes	**$ (146,047)**	$ (44,579)
Expected income taxes at the statutory rate of 27.00% (2017 – 26.93%)(1)	**(39,433)**	(12,007)
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	**3,963**	3,397
Non-taxable portion of foreign exchange loss (gain)	**5,201**	(11,719)
Effect of rate adjustments for foreign jurisdictions	**(27,400)**	(34,303)
Effect of change in deferred tax benefit not recognized(2)	**5,201**	(11,719)
Adjustments and assessments (3)	**492**	10,636
Income tax recovery	**$ (51,976)**	$ (55,715)

(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 $105 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).

(3) The Company is regularly subject to audit by the revenue authorities in the jurisdictions in which it operates. During the year ended December 31, 2017, the Company accepted an audit proposal from the Canada Revenue Agency which reduced certain non-capital loss tax pools by $39.3 million and resulted in a $10.6 million increase in deferred tax expense.

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. In July 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.

16. FINANCING AND INTEREST

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Interest on bank loan	**$ 4,108**	$ 2,985	**$ 10,297**	$ 8,573
Interest on long-term notes	**22,235**	21,541	**66,087**	67,059
Non-cash financing	**866**	1,008	**2,991**	3,288
Accretion on asset retirement obligations (note 10)	**2,820**	1,964	**7,450**	6,376
Financing and interest	**$ 30,029**	$ 27,498	**$ 86,825**	$ 85,296

17. FOREIGN EXCHANGE

	Three Months Ended September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Unrealized foreign exchange loss (gain)	**$ (20,583)**	$ (44,006)	**$ 38,136**	$ (87,389)
Realized foreign exchange loss (gain)	**(360)**	1,531	**1,887**	1,373
Foreign exchange loss (gain)	**$ (20,943)**	$ (42,475)	**$ 40,023**	$ (86,016)

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, bank loan 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 is 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:

	September 30, 2018		December 31, 2017		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL(1)					
Cash	**$ 45,159**	**$ 45,159**	$ —	$ —	Level 1
Financial derivatives	**$ 6,214**	**$ 6,214**	$ 18,510	$ 18,510	Level 2
Total	**$ 51,373**	**$ 51,373**	$ 18,510	$ 18,510	
Assets at amortized cost					
Trade and other receivables	**$ 178,167**	**$ 178,167**	$ 112,844	$ 112,844	—
Total	**$ 178,167**	**$ 178,167**	$ 112,844	$ 112,844	
Financial Liabilities					
FVTPL(1)					
Financial derivatives	**$ (108,487)**	**$ (108,487)**	$ (50,095)	$ (50,095)	Level 2
Total	**$ (108,487)**	**$ (108,487)**	$ (50,095)	$ (50,095)	
Financial liabilities at amortized cost					
Trade and other payables	**$ (317,118)**	**$ (317,118)**	$ (144,542)	$ (144,542)	—
Bank loan	**(488,804)**	**(490,565)**	(212,138)	(213,376)	—
Long-term notes	**(1,514,459)**	**(1,501,610)**	(1,474,184)	(1,430,902)	Level 1
Total	**$ (2,320,381)**	**$ (2,309,293)**	$ (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 during the nine months ended September 30, 2018 and 2017.

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	
	September 30, 2018	December 31, 2017	**September 30, 2018**	December 31, 2017
U.S. dollar denominated	**US$77,387**	US$51,665	**US$1,221,797**	US$1,294,615

Commodity Price Risk

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of November 1, 2018:

	Period	Volume	Price/Unit[1]	Index		Fair Value[2] *($ millions)*
Oil						
Basis swap	Oct 2018 to Dec 2018	6,000 bbl/d	WTI less US$14.24/bbl	WCS	$	8.4
3-way option[3]	Oct 2018 to Dec 2018	2,000 bbl/d	US$60.00/US$54.40/US$40.00	WTI	$	(3.1)
Fixed - Sell	Oct 2018 to Dec 2018	16,500 bbl/d	US$52.28/bbl	WTI	$	(43.1)
Fixed - Sell	Oct 2018 to Dec 2018	4,000 bbl/d	US$61.31/bbl	Brent	$	(11.6)
Fixed - Sell	Jan 2019 to Jun 2019	2,000 bbl/d	US$62.85/bbl	WTI	$	(4.3)
Fixed - Sell	Jan 2019 to Dec 2019	2,000 bbl/d	US$61.70/bbl	WTI	$	(9.4)
Swaption[4]	Jan 2019 to Dec 2019	2,000 bbl/d	US$61.70/bbl	WTI	$	(9.8)
Swaption[4]	Jan 2019 to Dec 2019	2,000 bbl/d	US$59.60/bbl	WTI	$	(10.9)
3-way option[3]	Jan 2019 to Dec 2019	2,000 bbl/d	US$70.00/US$60.00/US$50.00	WTI	$	(4.5)
3-way option[3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$72.60/US$65.00/US$55.00	WTI	$	(1.3)
3-way option[3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$72.50/US$66.00/US$56.00	WTI	$	(1.2)
3-way option[3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$73.00/US$66.00/US$56.00	WTI	$	(1.1)
3-way option[3]	Jan 2019 to Dec 2019	2,000 bbl/d	US$73.00/US$67.00/US$57.00	WTI	$	(2.1)
3-way option[3]	Jan 2019 to Dec 2019	2,000 bbl/d	US$74.00/US$68.00/US$58.00	WTI	$	(2.1)
3-way option[3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.00/US$69.90/US$60.00	WTI	$	(0.3)
3-way option[3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$76.00/US$71.00/US$61.00	WTI	$	(0.1)
3-way option[3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.50/US$65.50/US$55.50	Brent	$	(3.4)
3-way option[3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$77.55/US$70.00/US$60.00	Brent	$	(2.6)
3-way option[3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$83.00/US$73.00/US$63.00	Brent	$	(1.1)
3-way option[3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$78.00/US$73.00/US$63.00	WTI	$	—
Natural Gas						
Fixed - Sell	Oct 2018 to Dec 2018	15,000 mmbtu/d	US$3.01	NYMEX	$	(0.1)
Fixed - Sell	Oct 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO	$	0.4
Fixed - Sell	Nov 2018 to Mar 2019	5,000 GJ/d	$2.25	AECO	**$**	**—**
Total					**$**	**(103.3)**
Current asset						5.2
Non-current asset						—
Current liability						(98.5)
Non-current liability						(10.0)

(1) Based on the weighted average price per unit for the period.
(2) Fair values as at September 30, 2018. For the purposes of the table, contracts entered subsequent to September 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$70/US$60/US$50 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50/bbl; Baytex receives US$60.00/bbl when WTI is between US$50/bbl and US$60/bbl; Baytex receives the market price when WTI is between US$60/bbl and US$70/bbl; and Baytex receives US$70/bbl when WTI is above US $70/bbl.
(4) For these contracts, the counterparty has the right, if exercised on December 31, 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 November 1, 2018, Baytex had committed to deliver the following volumes of raw bitumen to market on rail:

Period	Volume
Oct 2018 to Dec 2018	8,340 bbl/d
Nov 2018 to Oct 2019	1,000 bbl/d
Oct 2018 to Dec 2019	2,500 bbl/d
Jan 2019 to Dec 2019	2,500 bbl/d
Jan 2019 to Dec 2020	5,000 bbl/d

Interest Rate Risk

Interest Rate Swaps

Baytex had the following interest rate swaps outstanding as of November 1, 2018:

Contract Type	Notional Amount	Maturity Date	Fixed Contract Price	Reference(1)	Fair Value *($ millions)*
Interest rate swap	$100 million	October 2020	2.02%	CDOR	$ 1.0
Total					**$ 1.0**
Current asset					0.5
Non-current asset					0.5

(1) Canadian Dollar Offered Rate.

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 September 30		Nine Months Ended September 30	
	2018	2017	**2018**	2017
Realized financial derivatives loss (gain)	**$ 30,854**	$ (2,795)	**$ 70,103**	$ (5,719)
Unrealized financial derivatives loss (gain)	**46**	21,145	**65,140**	(27,698)
Financial derivatives loss (gain)	**$ 30,900**	$ 18,350	**$ 135,243**	$ (33,417)

ABBREVIATIONS

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

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

CORPORATE INFORMATION

BOARD OF DIRECTORS

Neil J. Roszell
Chairman of the Board

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

Raymond T. Chan (2)(3)
Lead Independent Director

Mark R. Bly (1)(3)
Director

Gary R.J. Bugeaud (2)(4)
Director

Trudy M. Curran (2)(4)
Director

Naveen Dargan (1)(3)
Director

Gregory K. Melchin (1)(4)
Director

Kevin D. Olson (1)(2)
Director

David L. Pearce (3)(4)
Director

(1) Member of the Audit Committee
(2) Member of the Human Resources and Compensation Committee
(3) Member of the Reserves Committee
(4) Member of the Nominating and Governance Committee

HEAD OFFICE

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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

Bruce M. Beynon
Executive Vice President, Corporate Development

Rodney D. Gray
Executive Vice President and
Chief Financial Officer

Richard P. Ramsay
Executive Vice President and
Chief Operating Officer

Jason J. Jaskela
Vice President, Duvernay and
Eagle Ford Business Units

Brian G. Ector
Vice President, Capital Markets

Geoffrey J. Darcy
Vice President, Marketing

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

Jonathan L. Grimwood
Vice President, Exploration

Ryan M. Johnson
Vice President, Peace River Business Unit

Chad L. Kalmakoff
Vice President, Finance

M. Scott Lovett
Vice President, Corporate Development

Chad E. Lundberg
Vice President, Viking Business Unit

Scott E. Rideout
Vice President, Land

AUDITORS

KPMG LLP

LEGAL COUNSEL

Burnet, Duckworth & Palmer LLP

RESERVES ENGINEERS

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

TRANSFER AGENT

Computershare Trust Company of Canada

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: BTE