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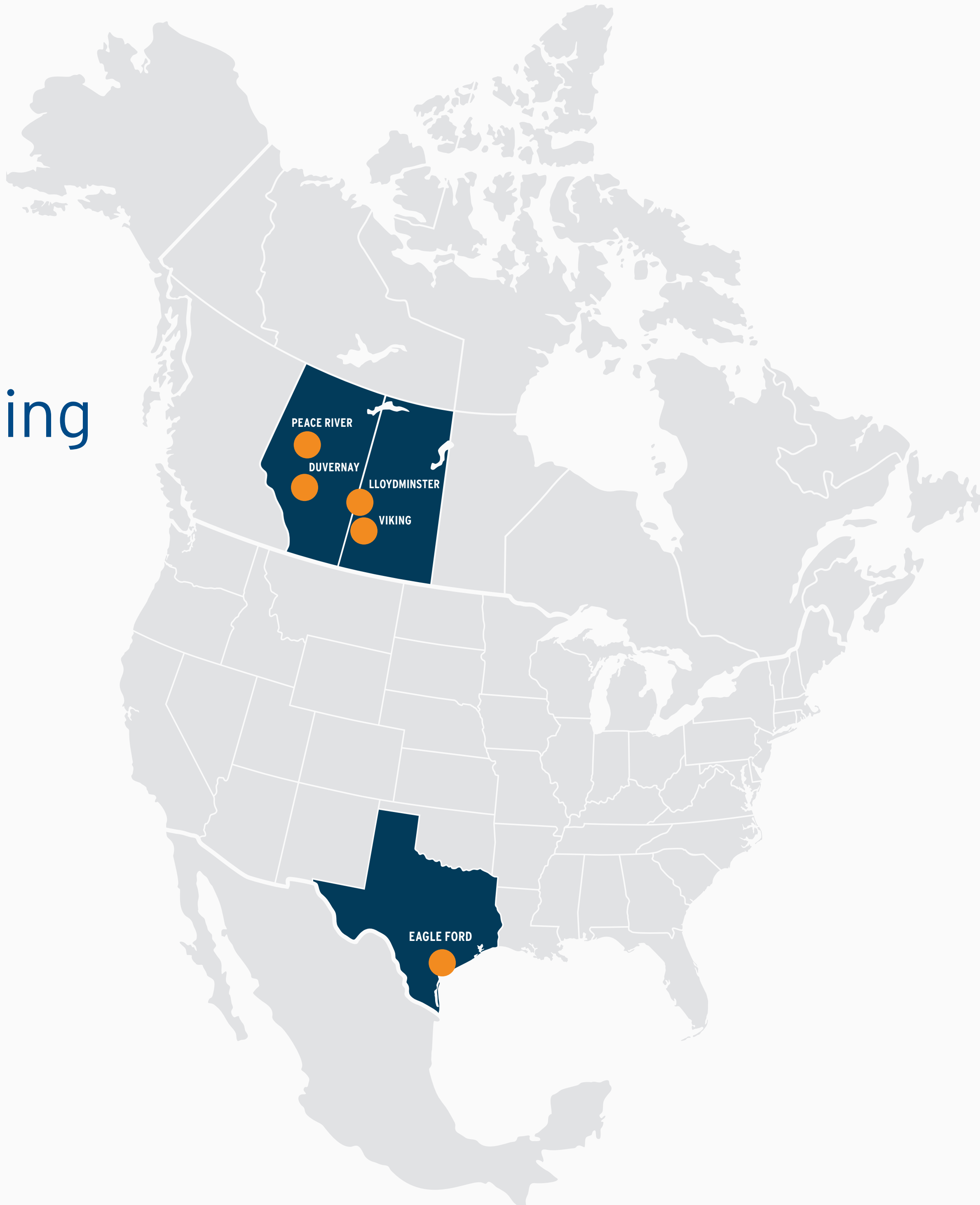
OUR PATH AHEAD

BAYTEX ENERGY CORP.

TSX BTE | NYSE BTE

2018 ANNUAL REPORT

Our Operating Areas



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SUMMARY

	Years Ended	
	December 31, 2018	December 31, 2017
FINANCIAL (thousands of Canadian dollars, except per common share amounts)		
Petroleum and natural gas sales	**$ 1,428,870**	$ 1,099,867
Adjusted funds flow [1]	**472,983**	347,641
Per share - basic	**1.35**	1.48
Per share - diluted	**1.35**	1.47
Net income (loss)	**(325,309)**	87,174
Per share - basic	**(0.93)**	0.37
Per share - diluted	**(0.93)**	0.37
Capital Expenditures		
Exploration and development expenditures [1]	**$ 495,721**	$ 326,266
Acquisitions, net of divestitures	**(1,818)**	59,857
Total oil and natural gas capital expenditures	**$ 493,903**	$ 386,123
Net Debt		
Bank loan [2]	**$ 522,294**	$ 213,376
Long-term notes [2]	**1,596,323**	1,489,210
Long-term debt	**2,118,617**	1,702,586
Working capital deficiency	**146,550**	31,698
Net debt [1]	**$ 2,265,167**	$ 1,734,284
Shares Outstanding - basic (thousands)		
Weighted average	**351,542**	234,787
End of period	**554,060**	235,451

	Years Ended	
	December 31, 2018	December 31, 2017
OPERATING		
Daily Production		
Light oil and condensate (bbl/d)	**29,264**	21,314
Heavy oil (bbl/d)	**25,954**	25,326
NGL (bbl/d)	**9,745**	9,206
Total liquids (bbl/d)	**64,963**	55,846
Natural gas (mcf/d)	**92,971**	86,375
Oil equivalent (boe/d @ 6:1) [3]	**80,458**	70,242
Netback (thousands of Canadian dollars)		
Total sales, net of blending and other expense [4]	**$ 1,360,038**	$ 1,040,522
Royalties	**(313,754)**	(241,892)
Operating expense	**(311,592)**	(269,283)
Transportation expense	**(36,869)**	(33,985)
Operating netback	**$ 697,823**	$ 495,362
General and administrative	**(45,825)**	(47,389)
Cash financing and interest	**(104,318)**	(100,482)
Realized financial derivatives (loss) gain	**(73,165)**	7,616
Other [5]	**(1,532)**	(7,466)
Adjusted funds flow [1]	**$ 472,983**	$ 347,641
Netback (per boe)		
Total sales, net of blending and other expense [4]	**$ 46.31**	$ 40.58
Royalties	**(10.68)**	(9.43)
Operating expense	**(10.61)**	(10.50)
Transportation expense	**(1.26)**	(1.33)
Operating netback [1]	**$ 23.76**	$ 19.32
General and administrative	**(1.56)**	(1.85)
Cash financing and interest	**(3.55)**	(3.92)
Realized financial derivatives (loss) gain	**(2.49)**	0.30
Other [5]	**(0.05)**	(0.29)
Adjusted funds flow [1]	**$ 16.11**	$ 13.56

Notes:

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

(2) Principal amount of instruments. The carrying amount of debt issue costs associated with the bank loan and long-term notes are excluded on the basis that these amounts have been paid by Baytex and do not represent an additional source of liquidity or repayment obligations.

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

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

(5) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and payments on onerous contracts. Refer to the 2018 MD&A for further information on these amounts.

Advisory Regarding Forward-Looking Statements and Initial Production Rates

This report contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that current oil prices will have a very positive impact on our adjusted funds flow; that we will strengthen our balance sheet in 2019; the trend for our production volumes; our expected Q1/2019 capital expenditures; that 80% of our capital spending will be directed to high operating netback assets in the Eagle Ford and Viking; our forecast adjusted funds flow, debt repayment, production and net debt to EBITDA ratio for 2019; that 90% of our production is the Viking and Duvernay is light oil; that 2018 repositioned us to have strong free cash flow; 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 our extended reach horizontal wells are economic; that our Peace River assets generate some of the strongest capital efficiencies in the oil and gas industry; that we continue to prudently advance the delineation of our East Duvernay Shale assets; that we expect to request an extension to our credit facilities in 2019; our ability to partially reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts for commodity prices, foreign exchange rates and interest rates; the percentage of our net crude oil and natural gas exposure that is hedged for 2019 and the amount and percentage of heavy oil production we expect to delivery by crude by rail and the percentage of crude by rail deliveries that do not have WCS exposure; the expected impact of improved pricing on our adjusted funds flow; that deleveraging remains a priority and our planned uses for adjusted funds flow in 2019; for the Eagle Ford and Viking in Q1/2019: the percentage of our capital spending directed to the assets and the number of drilling rigs and frac crews on our lands; the number of wells to be drilled in the Viking in 2019; the number of wells to be brought on production in the Eagle Ford in 2019; that we will execute a small heavy oil program in the first half of 2019 that could move higher if prices and egress improve; for the East Duvernay Shale in 2019: that we will continue to prudently advance its evaluation, that we will drill four wells in Q1/2019 that if successful will delineate 100 to 125 sections of land; our 2019 production, capital expenditure guidance, adjusted funds flow, adjusted funds flow per share and operating netback guidance; our expected royalty rate and operating, transportation, general and administration and interest expenses for 2019; our expected leasing expenditures and asset retirement obligation spending for 2019; the sensitivity of our 2019 Adjusted Funds Flow to changes in WTI, WCS, MSW and NYMEX prices and the C$/US$ exchange rate; our reserves life index; the net present value before income taxes of the future net revenue attributable to our reserves; forecast prices for petroleum and natural gas; forecast inflation and exchange rates; future development costs; the value of our undeveloped land holdings and our estimated net asset value. In addition, information and statements relating to reserves and contingent resources are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that they can be profitably produced in the future. We refer you to the end of the Management's Discussion and Analysis section of this report for our advisory on forward-looking statements.

This report contains references to average 30-day initial production rates and other short-term production rates which 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.

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 that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our cash flow on a continuing basis. Transaction costs associated with the Raging River combination are excluded from adjusted funds flow as we consider the costs non-recurring and not reflective of our ability to generate adjusted funds flow on an ongoing basis. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the three months and year ended December 31, 2018.

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

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of 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 and provides a key measure to assess our liquidity. The current portion of financial derivatives is excluded as the valuation of the underlying contracts is subject to a high degree of volatility prior to the ultimate settlement. Onerous contracts are excluded from net debt as the underlying contracts do not represent an available source of liquidity. We use the principal amounts of the bank loan and long-term notes outstanding in the calculation of net debt as these amounts represent our ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the bank loan and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of liquidity or repayment obligation.

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

MESSAGE TO SHAREHOLDERS

In an environment of volatile commodity prices, 2018 was a defining year for Baytex as we repositioned our company as a North American crude oil producer with strong free cash flow and an improved balance sheet. We delivered on our commitment to grow production and reserves while continuing to drive cost and capital efficiency in our operations, and balance our capital structure.

On August 22, 2018, we completed the transformational combination with Raging River Exploration Inc. (“Raging River”). This $1.6 billion transaction increased our light oil exposure and operational control of our properties and strengthened our balance sheet.

We have successfully integrated the two companies, undertaken a strategic review of our operations, confirmed the organic growth opportunities in our diversified portfolio of assets and delivered on our near-term operational targets. In essence, we have created a new Baytex - with stronger assets and organizational capability than ever before.

One of the key benefits of the combination is 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 operating netback Viking light oil production in Canada. Today our product mix is approximately 83% liquids (45% light oil, 27% heavy oil and 10% NGLs) and 17% natural gas.

In 2018, our annual production of 80,458 boe/d, exceeded the high end of our guidance, while capital expenditures of $496 million were in line with our guidance. Our fourth quarter 2018 production increased to 98,890 boe/d. We are very pleased with our operating results. In the Eagle Ford, we continued to see strong well performance driven by enhanced completions in the oil window of our acreage. In the Viking, our expanded use of extended reach horizontal wells continue to exceed expectations with multiple, previously untested sections proving economic. Our heavy oil assets, in both Peace River and Lloydminster, delivered strong results, despite the volatility surrounding heavy oil differentials in Canada. We also continue to prudently advance our Duvernay shale light oil asset, an early stage light oil resource play.

We delivered adjusted funds flow of $473 million in 2018 and our diligent focus on cost control drove our cash costs (operating, transportation and general and administrative expenses) lower by 4% on a boe basis, as compared to the mid-point of original guidance. We ended 2018 with strong financial liquidity. Our credit facilities are approximately 50% undrawn and our first long-term note maturity is not until 2021. Our net debt totaled $2.265 billion at December 31, 2018, which includes four series of long-term notes that total $1.6 billion.

In aggregate, we replaced 106% of total 2018 production, adding 31 mmboe of proved plus probable reserves through development activities. Inclusive of the Raging River transaction, we replaced 422% of total 2018 production with 124 mmboe of proved plus probable reserves additions.

We also achieved strong health, safety and environmental performance and strong regulatory compliance across all of our operating jurisdictions. In 2019, we will publish our fourth Corporate Responsibility Report, focusing on environmental, social and economic metrics. We believe that corporate responsibility is a key component to achieving enduring success in resource development.

Looking Forward

As we look ahead, we are well positioned to execute our business plan and further strengthen our balance sheet. With WTI trading at US$57 at the time of writing, in combination with the narrowing of Canadian differentials, we expect a positive impact on our adjusted funds flow.

As a result of current activity levels, excellent well performance in the Eagle Ford and outstanding operating efficiency across all of our assets, our first quarter 2019 volumes have exceeded expectations trending above 97,000 boe/d.

We are on pace for $155 million of capital expenditures in Q1 2019, which remains consistent with the mid-point of our guidance range of $600 million. Approximately 80% of those expenditures are being directed towards our light oil assets in the Eagle Ford and Viking.

Further deleveraging remains a top priority for Baytex. Based on the forward strip for 2019, we are projecting adjusted funds flow of approximately $800 million – a 32% increase from $605 million that was forecast at the outset of 2019. This will allow up to $200 million of debt repayment while maintaining production at the mid-point of our guidance of 95,000 boe/d.

Baytex's success is due to our dedicated and talented team of employees who align with our strategy, consistently deliver on our plans and drive value for our shareholders. Complementing our leadership team and committed employees, our Board of Directors is an indispensable source of guidance and support which contribute greatly to our success. With the combined team, we are confident we have the skills, experience and focus that will create a more prosperous future

We look forward to executing our plans in 2019 for the ongoing benefit of all stakeholders and we thank you for your continued support.

Sincerely,

Edward D. LaFehr
President and Chief Executive Officer

March 6, 2019

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 years ended December 31, 2018 and 2017. This information is provided as of March 5, 2019. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three months and year ended December 31, 2018 ("Q4/2018" and "2018") have been compared with the results for the three months and year ended December 31, 2017 ("Q4/2017" and "2017"). This MD&A should be read in conjunction with the Company's audited consolidated financial statements ("consolidated financial statements") for the years ended December 31, 2018 and 2017, together with the accompanying notes and the Annual Information Form for the year ended December 31, 2018. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages and per common share amounts or as otherwise noted.

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

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

BAYTEX ENERGY CORP.

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

On August 22, 2018, Baytex and Raging River Exploration Inc. ("Raging River") completed the strategic combination of the two companies (the "Strategic Combination") by way of a plan of arrangement whereby Baytex acquired all of the issued and outstanding common shares of Raging River. The Strategic Combination increased our light oil exposure and operational control of our properties while improving our leverage ratios. Production from Raging River's properties is approximately 90% high operating netback light oil from the Viking and Duvernay. The addition of the primarily operated assets to our portfolio increased our inventory of drilling prospects and increased our ability to effectively allocate capital. We recorded transaction costs of $13.1 million related to the Strategic Combination.

2018 ANNUAL HIGHLIGHTS

Baytex delivered solid operating and financial results for 2018. We invested $495.7 million on exploration and development activities which was within our guidance range of $450 - $500 million and generated adjusted funds flow of $473.0 million. Production for 2018 averaged 80,458 boe/d due to strong well performance and exceeded the high end of our guidance range of 79,000 - 80,000 boe/d, despite shut-in and deferred production in Q4/2018. Production from the Strategic Combination and strong well performance resulted in a 10,216 boe/d or 15% increase in production from 70,242 boe/d for 2017.

We closed the Strategic Combination on August 22, 2018 and operations have continued at or above expectations for both the legacy Baytex and Raging River assets. Operating and financial results include Raging River operations from the closing date. Production from the properties averaged approximately 25,000 boe/d between closing and December 31, 2018 which contributed 9,165 boe/d of production to 2018. Baytex issued 315.3 million common shares and assumed Raging River's net debt of approximately $363.6 million upon closing the transaction.

In the U.S., we invested $193.6 million on exploration and development activities and drilled 91 (20.8 net) wells and brought 120 (26.2 net) wells on production during 2018. Exploration and development expenditures in the U.S. were $19.4 million lower in 2018 as drilling and completion was lower relative to 2017 when we drilled 140 (32.8 net) wells and commenced production from 115 (28.7 net) wells. Strong well performance from wells brought online during 2018 generated average daily production of 37,076 boe/d in 2018 which is slightly higher than 36,678 boe/d for 2017 despite lower completion activity in 2018.

In Canada, exploration and development expenditures of $302.1 million were focused on our our heavy oil properties at Peace River and Lloydminster and our light oil Viking and Duvernay properties. Our heavy oil drilling activities during 2018 included 95 (70.5 net) wells drilled at Lloydminster and 13 (13.0 net) wells drilled at Peace River. Exploration and development activity on our light oil in 2018 included 121 (83.0 net) wells drilled on our Viking lands and 4 (4.0 net) wells drilled on our Duvernay lands subsequent to closing the Strategic Combination. Average daily production of 43,382 boe/d was 9,818 boe/d or 29% higher than 33,564 boe/d in 2017 which reflects the production contribution from the Strategic Combination.

Commodity prices continued to be volatile in 2018. Benchmark prices for crude oil strengthened going into Q4/2018 as robust global demand and ongoing OPEC production curtailments continued to reduce global inventory levels. Increasing production and geopolitical factors contributed to a sharp decline in global crude oil prices in Q4/2018. The West Texas Intermediate ('WTI") benchmark oil price averaged US$58.81/bbl in Q4/2018, which was down from US$69.50/bbl in Q3/2018 after waivers granted by the United States mitigated the impact of sanctions on Iranian production which became effective in November. The West Texas Intermediate ("WTI") benchmark oil price averaged US$64.77/bbl for 2018 which is a US$13.82/bbl increase from US$50.95/bbl for 2017. Market prices for light and heavy grades of Canadian crude oil were impacted by increasing oil production and a lack of egress in Western Canada and traded at wider differentials to WTI in 2018 relative to 2017. Edmonton par averaged $69.31/bbl in 2018 which represents a differential of US$11.30/bbl to WTI as compared to a US$2.47/bbl differential in 2017. The Western Canadian Select ("WCS") heavy oil differential averaged US$26.31/bbl in 2018 relative to a differential of US$11.98/bbl in 2017. Production curtailments mandated by the Alberta Government came into effect beginning in January 2019 and have recently resulted in a narrowing of Canadian oil differentials in 2019.

We generated adjusted funds flow of $473.0 million in 2018 which is $125.3 million or 36% higher than $347.6 million for 2017. The increase in adjusted funds flow was primarily a result of higher realized pricing combined with the 15% increase in production for 2018 relative to 2017. Our realized price of $46.31/boe for 2018 increased $5.73/boe from $40.58/boe for 2017 and reflects stronger pricing received on our U.S. production with the increase in U.S. benchmark prices for the first ten months of 2018. The increase in our realized price was partially offset by higher royalties, operating and transportation expense in 2018 and resulted in a $202.5 million increase in operating netback relative to 2017. Our operating netback in 2018 was also offset by realized hedging losses of $73.2 million compared to realized gains of $7.6 million in 2017.

In 2018 we reported a net loss of $325.3 million compared to net income of $87.2 million in 2017. Depletion and depreciation increased by $76.8 million in 2018 following the Strategic Combination. In 2018 we recorded an unrealized gain on financial derivatives of $116.7 million as compared to an unrealized loss of $2.4 million in 2017. The Canadian dollar weakened in 2018 which resulted in an unrealized foreign exchange loss of $106.1 million primarily associated with the remeasurement of our U.S. dollar denominated debt. We recorded an unrealized foreign exchange gain of $86.6 million in 2017 due to a strengthening of the Canadian dollar through 2017. The net loss for 2018 includes a $285.3 million impairment expense recorded in Q4/2018 due to a change in development plans for our oil and natural gas properties.

At December 31, 2018, net debt was $2,265.2 million, an increase of $530.9 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 combined with a $107.1 million increase in the reported amount of our U.S. dollar denominated debt due to a weaker Canadian dollar at December 31, 2018 compared to December 31, 2017. The precipitous widening of Canadian oil differentials and decline in global benchmark oil prices during Q4/2018 resulted in exploration and development expenditures for November and December 2018 exceeding adjusted funds flow by $76.8 million which also contributed to the increase in net debt relative to December 31, 2017.

GUIDANCE

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

	Current (1)	2018
Exploration and development capital	$450 - $500 million	$495.7 million
Production (boe/d)	79,000 to 80,000	80,458
Expenses:		
Royalty rate	~ 22.0%	23.1%
Operating	$10.50 - $10.75/boe	$10.61/boe
Transportation	$1.25 - $1.30/boe	$1.26/boe
General and administrative	~ $45 million ($1.55/boe)	$45.8 million ($1.56/boe)
Cash interest	~ $104 million ($3.58/boe)	$104.3 million ($3.55/boe)

(1) Current as of November 2, 2018.

We delivered strong operating and financial results for 2018. The disciplined execution of our exploration and development program resulted in total spending of $495.7 million which was within our guidance range of $450 - $500 million. Strong well results in the

U.S. and Canada resulted in production of 80,458 boe/d which exceeded our guidance range of 79,000 - 80,000 boe/d for 2018. Our royalty rate, along with operating, transportation, general and administrative, and cash interest expense were all in line with 2018 guidance and expectations.

The following table summarizes our 2019 guidance as previously released on December 17, 2018.

	2019 Guidance
Exploration and development capital	$550 - $650 million
Production (boe/d)	93,000 to 97,000
Expenses:	
Royalty rate	~ 20.0%
Operating	$10.75 - $11.25/boe
Transportation	$1.25 - $1.35/boe
General and administrative	~ $44 million ($1.27/boe)
Cash interest	~ $112 million ($3.23/boe)

RESULTS OF OPERATIONS

The Canadian operating segment includes our light oil assets in Viking and Duvernay subsequent to closing of the Strategic Combination, 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

	Years Ended December 31					
	2018			2017		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Light oil and condensate	**8,959**	**20,305**	**29,264**	1,163	20,151	21,314
Heavy oil	**25,954**	**—**	**25,954**	25,326	—	25,326
Natural Gas Liquids ("NGL")	**1,199**	**8,546**	**9,745**	1,044	8,162	9,206
Total liquids (bbl/d)	**36,112**	**28,851**	**64,963**	27,533	28,313	55,846
Natural gas (mcf/d)	**43,622**	**49,349**	**92,971**	36,186	50,189	86,375
Total production (boe/d)	**43,382**	**37,076**	**80,458**	33,564	36,678	70,242
Production Mix						
Light oil and condensate	**21%**	**55%**	**37%**	3%	55%	30%
Heavy oil	**60%**	**—%**	**32%**	76%	—%	36%
NGL	**3%**	**23%**	**12%**	3%	22%	13%
Natural gas	**16%**	**22%**	**19%**	18%	23%	21%

Production of 80,458 boe/d for 2018 is 10,216 boe/d or 15% higher than 70,242 boe/d in 2017. Strong well results in the U.S. resulted in production of 37,076 boe/d in 2018 which is consistent with 36,678 boe/d in 2017 despite lower completion activity on our lands. In Canada, production of 43,382 boe/d in 2018 was 9,818 boe/d higher than 33,564 boe/d in 2017 primarily due to the 9,165 boe/d production contribution from the Strategic Combination.

Production from our Canadian operations was 43,382 boe/d in 2018 up 29% from 33,564 boe/d in 2017. The increase is primarily from the Strategic Combination which added 9,165 boe/d to our annual average production. The properties from the combination were primarily light oil which increased our light oil production to 21% of our Canadian production in 2018 from 3% in 2017 and up to 40% in Q4/2018 compared to 3% in Q4/2017. Strong well results from our heavy oil drilling program in Peace River and Lloydminster resulted in heavy oil production of 25,954 boe/d in 2018 which is slightly higher than 25,326 boe/d in 2017.

U.S. production averaged 37,076 boe/d in 2018 which is up from 36,678 boe/d for 2017. Strong performance from wells brought on production in late 2017 and throughout 2018 resulted in higher production relative to 2017 and resulted in Q4/2018 production of 38,437 boe/d as compared to 37,362 boe/d in Q4/2017. During 2018 we commenced production from 120 (26.2 net) wells compared to 115 (28.7 net) wells on production during 2017.

Our production guidance range for 2019 is 93,000 to 97,000 boe/d as we will have a full year of production from the Strategic Combination.

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 remained volatile in 2018. Benchmark prices for crude oil strengthened going into Q4/2018 as robust global demand and ongoing OPEC production curtailments continued to reduce global inventory levels. Increasing production and geopolitical factors contributed to a sharp decline in global crude oil prices in Q4/2018 after waivers granted by the United States mitigated the impact of sanctions on Iranian production which became effective in November.

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$64.77/bbl during 2018, representing an increase of US$13.82/bbl compared to 2017 when the benchmark price averaged US$50.95/bbl.

Our U.S. crude oil production is primarily priced off the Louisiana Light Sweet ("LLS") stream at St. James, Louisiana, which is the representative benchmark for light oil pricing at the U.S. Gulf coast. During 2018, LLS averaged US$70.09/bbl, which is a premium of US$5.32/bbl relative to WTI, compared to an LLS price of US$53.26/bbl or a US$2.31/bbl premium to WTI for 2017.

Benchmark prices for Canadian light and heavy grades of crude oil were impacted by ongoing pipeline capacity constraints, a lack of rail transport capacity and increasing Western Canadian crude oil production, which resulted in benchmark pricing trading at a wider discount to WTI in 2018. After construction on the Trans Mountain pipeline expansion was delayed during Q3/2018 the differentials for light and heavy grades of Canadian oil widened. In Q4/2018, the WCS heavy differential averaged US$39.42/bbl and the Edmonton par differential averaged US$26.51/bbl after averaging US$21.93/bbl and US$6.03/bbl for the first nine months of 2018, respectively. Production curtailments mandated by the Alberta Government have resulted in a narrowing of the Canadian oil differentials early in 2019.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price. The Edmonton par price averaged $69.31/bbl for 2018 compared to $62.92/bbl for 2017 as the increase in WTI more than offset the wider differential in 2018 compared to 2017. Edmonton par traded at a US$11.30/bbl discount to WTI in 2018 compared to a US$2.47/bbl discount for 2017. The price received for our heavy oil production in Canada is based on the WCS benchmark price which is the representative benchmark for heavy grades of crude oil in Western Canada. The WCS heavy oil differential to WTI averaged US$26.31/bbl in 2018 as compared to US$11.98/bbl for 2017. As a result, the WCS heavy oil benchmark price of $49.85/bbl decreased $0.74/bbl from $50.59/bbl in 2017 despite a $17.82/bbl increase in WTI (expressed in Canadian dollars) over the same periods.

Natural Gas

North American natural gas prices were lower throughout most of 2018 relative to 2017 as natural gas supply growth outpaced growth in demand. Canadian natural gas prices remained challenged during 2018 as a lack of egress in Western Canada continues to impact natural gas prices in the region. The effect of increasing supply from U.S. shale production was mitigated by higher demand for U.S. consumption and exports in 2018 as U.S. benchmark prices were relatively consistent with 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 $1.54/mcf during 2018 which is $0.89/mcf lower than the benchmark average of $2.43/mcf during 2017.

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. During 2018, the NYMEX natural gas benchmark averaged US$3.09/mmbtu which is consistent with US$3.11/mmbtu for 2017.

The following tables compare selected benchmark prices and our average realized selling prices for the years ended December 31, 2018 and 2017.

	Years Ended December 31		
	2018	2017	Change
Benchmark Averages			
WTI oil (US$/bbl)(1)	**64.77**	50.95	13.82
WTI oil (CAD$/bbl)	**83.95**	66.13	17.82
WCS heavy oil differential (US$/bbl)	**(26.31)**	(11.98)	(14.33)
WCS heavy oil differential (CAD$/bbl)	**(34.10)**	(15.54)	(18.56)
WCS heavy oil (US$/bbl)(2)	**38.46**	38.97	(0.51)
WCS heavy oil (CAD$/bbl)	**49.85**	50.59	(0.74)
LLS oil (US$/bbl)(3)	**70.09**	53.26	16.83
LLS oil (CAD$/bbl)	**90.85**	69.12	21.73
CAD/USD average exchange rate	**1.2962**	1.2979	(0.0017)
Edmonton par oil ($/bbl)	**69.31**	62.92	6.39
AECO natural gas price ($/mcf)(4)	**1.54**	2.43	(0.89)
NYMEX natural gas price (US$/mmbtu)(5)	**3.09**	3.11	(0.02)

(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.

	Years Ended December 31					
	2018			2017		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices(1)						
Light oil and condensate ($/bbl)	**$ 51.78**	**$ 85.96**	**$ 75.50**	$ 56.24	$ 64.17	$ 63.74
Heavy oil ($/bbl)(2)	**36.20**	**—**	**36.20**	38.46	—	38.46
NGL ($/bbl)	**33.21**	**31.10**	**31.36**	27.98	25.59	25.86
Natural gas ($/mcf)	**1.48**	**4.20**	**2.92**	2.21	3.99	3.24
Weighted average ($/boe)(2)	**$ 34.76**	**$ 59.83**	**$ 46.31**	$ 34.22	$ 46.41	$ 40.58

(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 $46.31/boe for 2018 which is up $5.73/boe from $40.58/boe for 2017. Our realized price in the U.S. was $59.83/boe in 2018 which is up $13.42/boe or 29% from $46.41/boe in 2017 due to the increase in U.S. benchmark prices relative to 2017. In Canada, our realized price of $34.76/boe for 2018 was relatively consistent with $34.22/boe for 2017 despite a significant widening of Canadian light and heavy oil differentials during Q4/2018. The impact of wider differentials in Canada was mitigated by a higher WTI price and an improvement in our realized pricing 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.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price of $51.78/bbl decreased $4.46/bbl from 2017 despite a $6.39/bbl increase in the benchmark price due to a majority of our 2018 light oil and condensate production occurring after closing of the Strategic Combination combined with a significant widening of Canadian light oil differentials during Q4/2018. The Edmonton par benchmark price averaged $42.68/bbl during Q4/2018 compared to the first nine months of the year when the benchmark price averaged $78.19/bbl which resulted in a lower increase in our realized price for 2018 relative to the increase in the benchmark price. During Q4/2018 our realized light oil price of $40.55/bbl represents a discount of $2.13/bbl to the Edmonton par benchmark of $42.68/bbl and is more representative of the Canadian light oil price realizations we expect in future periods.

We compare the price received for our U.S. light oil and condensate production to the LLS benchmark. Our realized light oil and condensate price averaged $85.96/bbl for 2018 which is a $21.79/bbl increase compared to $64.17/bbl for 2017, consistent with a $21.73/bbl increase in LLS benchmark pricing expressed in Canadian dollars. Expressed in U.S. dollars, our realized light oil and condensate price of US$66.32/bbl represents a US$3.77/bbl discount to the LLS benchmark for 2018 which is consistent with a US $3.82/bbl discount for 2017.

Our realized heavy oil price, net of blending and other expense averaged $36.20/bbl in 2018 compared to $38.46/bbl in 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. Our realized heavy oil price was negatively impacted by an increase in the cost of blending diluent in 2018. As a result, our realized heavy oil price decreased by $2.26/bbl in 2018 compared to the $0.74/bbl decrease in the WCS benchmark price.

Our realized NGL price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes and changes in the market prices of the underlying products. In Canada, our realized NGL price was $33.21/bbl in 2018 or 40% of WTI (expressed in Canadian dollars) which is relatively consistent with $27.98/bbl or 42% of WTI in 2017. Our U.S. NGL realized price was $31.10/bbl or 37% of WTI (expressed in Canadian dollars) as compared to $25.59/bbl or 39% of WTI (expressed in Canadian dollars) for 2017. Our realized NGL pricing improved in 2018 but was lower as a percentage of WTI as compared to 2017 due to the market prices for butane and propane which were lower as a percentage of WTI in 2018 as compared to 2017.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price for 2018 was $1.48/mcf representing a 33% decrease from $2.21/mcf in 2017. This decrease is relatively consistent with the decrease in the AECO benchmark price which was $1.54/mcf in 2018 or 37% lower than $2.43/mcf in 2017.

Our realized natural gas price in the U.S. was $4.20/mmbtu for 2018 and was $3.99/mmbtu in 2017 which is consistent with the NYMEX benchmark (expressed in Canadian dollars) which was US$3.09/mmbtu in 2018 and US$3.11/mmbtu for 2017.

Petroleum and Natural Gas Sales

	Years Ended December 31					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 169,335**	**$ 637,055**	**$ 806,390**	$ 23,876	$ 471,997	$ 495,873
Heavy oil	**411,794**	**—**	**411,794**	414,902	—	414,902
NGL	**14,531**	**97,008**	**111,539**	10,664	76,234	86,898
Total liquids sales	**595,660**	**734,063**	**1,329,723**	449,442	548,231	997,673
Natural gas sales	**23,555**	**75,592**	**99,147**	29,130	73,064	102,194
Total petroleum and natural gas sales	**619,215**	**809,655**	**1,428,870**	478,572	621,295	1,099,867
Blending and other expense	**(68,832)**	**—**	**(68,832)**	(59,345)	—	(59,345)
Total sales, net of blending and other expense	**$ 550,383**	**$ 809,655**	**$ 1,360,038**	$ 419,227	$ 621,295	$ 1,040,522

Total sales, net of blending and other expense, was $1,360.0 million for 2018 which is an increase of $319.5 million from $1,040.5 million reported for 2017. Total sales increased with more production in 2018 compared to 2017 along with the increase in realized prices. Higher production in 2018 was primarily a result of the Strategic Combination and resulted in a $172.7 million increase in total sales relative to 2017. Improved commodity prices combined with a higher weighting of light oil production resulted in stronger realized pricing in 2018 and increased sales by $146.8 million compared to 2017.

In Canada, total sales, net of blending and other expense was $550.4 million for 2018 which is an increase of $131.2 million or 31% from $419.2 million in 2017. The increase is primarily attributed to the 9,165 boe/d of light oil weighted production associated with the Strategic Combination as our realized price of $34.76/boe in 2018 is consistent with $34.22/boe in 2017.

Petroleum and natural gas sales in the U.S. were $809.7 million for 2018 and increased 30% or $188.4 million from $621.3 million reported for 2017. The increase was driven primarily by a 29% increase in realized pricing of $59.83/boe for 2018 compared to $46.41/boe in 2017 with the remaining increase from production of 37,076 boe/d in 2018 which is 1% higher than 36,678 boe/d in 2017.

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 years ended December 31, 2018 and 2017.

	Years Ended December 31					
	2018			2017		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 72,700**	**$ 241,054**	**$ 313,754**	$ 58,672	$ 183,220	$ 241,892
Average royalty rate[(1)]	**13.2%**	**29.8%**	**23.1%**	14.0%	29.5%	23.2%
Royalty rate per boe	**$ 4.59**	**$ 17.81**	**$ 10.68**	$ 4.79	$ 13.69	$ 9.43

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

Total royalties for 2018 were $313.8 million which is $71.9 million higher than $241.9 million in 2017 due to the increase in total sales as our royalty rate in 2018 was consistent with 2017.

In Canada, total royalties were $72.7 million or 13.2% of sales, net of blending and other expense for 2018 compared to $58.7 million or 14.0% of sales, net of blending and other expense reported in 2017. Our overall royalty rate in Canada decreased following the Strategic Combination as the royalty rate of 10.4% on our Viking and Duvernay properties is lower than the rate on our heavy oil properties.

Total royalties in the U.S. were $241.1 million or 29.8% of sales for 2018 compared to $183.2 million or 29.5% of sales reported for 2017. The royalty rate on our U.S. production does not vary with price but can vary across our acreage. Royalties for 2018 averaged 29.8% of petroleum and natural gas sales which is consistent with 29.5% for 2017. The increase in total royalties in 2018 compared to 2017 is consistent with the increase in total petroleum and natural gas sales over the same period.

We expect royalties to average approximately 20% of total sales during 2019 compared to our 2018 royalty rate of 23.1%. We expect a lower royalty rate in 2019 due to a higher proportion of our production coming from our Canadian properties which have a lower royalty rate than our U.S. properties.

Operating Expense

	Years Ended December 31					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 221,717**	**$ 89,875**	**$ 311,592**	$ 181,995	$ 87,288	$ 269,283
Operating expense per boe	**$ 14.00**	**$ 6.64**	**$ 10.61**	$ 14.86	$ 6.52	$ 10.50

Operating expense was $311.6 million ($10.61/boe) in 2018 compared to $269.3 million ($10.50/boe) for 2017. The increase in total operating expense can be attributed to higher production in 2018 relative to 2017 as per unit operating expense was relatively consistent in both periods.

In Canada, operating expense was $221.7 million ($14.00/boe) for 2018 compared to $182.0 million ($14.86/boe) for 2017. Total operating expense in Canada increased with the addition of production from the Strategic Combination as these properties contributed approximately $38.6 million of operating expense in 2018. Per unit operating expense in Canada was slightly lower in 2018 compared to 2017 as per unit operating expense of $11.21/boe on our Viking and Duvernay properties is lower relative to our other Canadian properties.

U.S. operating expense of $89.9 million ($6.64/boe) for 2018 was relatively consistent with $87.3 million ($6.52/boe) for 2017. The increase in total operating expense is a result of slightly higher production in 2018 as per unit operating costs were relatively consistent with 2017. Expressed in U.S. dollars, operating expense for our U.S. properties of US$5.12/boe in 2018 is fairly consistent with US $5.02/boe for 2017.

We expect 2019 per unit operating expense to range between $10.75 - $11.25/boe which is slightly higher than $10.61/boe in 2018. With the Strategic Combination, we will have proportionately more production from Canada in 2019 which will increase our per unit operating expense in 2019.

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 years ended December 31, 2018 and 2017.

	Years Ended December 31					
	2018			2017		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 36,869**	**$ —**	**$ 36,869**	$ 33,985	$ —	$ 33,985
Transportation expense per boe	**$ 2.33**	**$ —**	**$ 1.26**	$ 2.77	$ —	$ 1.33

Transportation expense was $36.9 million ($1.26/boe) for 2018 compared to $34.0 million ($1.33/boe) for 2017. In Canada, transportation costs increased approximately $5.2 million as a result of the Strategic Combination. This increase was offset by lower transportation charges on our other properties due to increased rail deliveries in 2018 along with changes in certain gas marketing arrangements that resulted in lower gas transportation costs. Transportation charges per unit decreased from $2.77/boe in 2017 to $2.33/boe in 2018 as per unit transportation costs on our Duvernay and Viking properties are lower than our heavy oil properties.

For 2019 we expect transportation costs to average $1.25 - $1.35/boe which is consistent with our 2018 per unit transportation costs of $1.26/boe.

Blending and Other Expense

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

Blending and other expense was $68.8 million for 2018 compared to $59.3 million for 2017. The increase in blending and other expense during 2018 is due to higher diluent prices combined with an increase in the quantity of diluent required to meet pipeline specifications relative to 2017. The density of blending diluent available in 2018 was heavier relative to 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 years ended December 31, 2018 and 2017.

	Years Ended December 31		
($ thousands)	**2018**	2017	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ (74,902)**	$ 4,552	$ (79,454)
Natural gas	**1,765**	3,064	(1,299)
Interest and financing	**(28)**	—	(28)
Total	**(73,165)**	7,616	(80,781)
Unrealized financial derivatives gain (loss)			
Crude oil	**117,087**	(16,841)	133,928
Natural gas	**(697)**	14,402	(15,099)
Interest and financing	**325**	—	325
Total	**116,715**	(2,439)	119,154
Total financial derivatives gain (loss)			
Crude oil	**42,185**	(12,289)	54,474
Natural gas	**1,068**	17,466	(16,398)
Interest and financing	**297**	—	297
Total	**$ 43,550**	$ 5,177	$ 38,373

The realized financial derivatives loss of $73.2 million for 2018 is a result of crude oil and natural gas market price indices settling at levels above those set in our fixed price contracts.

Realized losses of $74.9 million on crude oil financial derivatives were driven by $88.2 million of losses on our WTI swap contracts and $19.4 million of losses on our Brent swap contracts as the market price of WTI and Brent settled above our contract prices. We also recorded $5.1 million of realized losses on our 3-way option contracts as the market price of WTI settled above our contracted sold call price during 2018. Losses on WTI and Brent contracts were partially offset by gains of $37.8 million on our WCS differential contracts as the index was wider than the differentials set in our contracts during 2018.

We recorded realized gains of $1.8 million on our natural gas financial derivatives during 2018. These gains were primarily a result of the AECO price index for 2018 settling below the average fixed price on AECO contracts in place for 2018.

At December 31, 2018, the fair value of our financial derivative contracts represent a net asset of $79.6 million compared to a net liability of $31.6 million at December 31, 2017. The net asset of $79.6 million as at December 31, 2018 is primarily a result of futures pricing for crude oil indices being lower than the prices set in our crude oil financial derivatives contracts for 2019.

We had the following commodity financial derivative contracts as at March 5, 2019.

	Remaining Period	Volume	Price/Unit[1]	Index
Oil				
Fixed - Sell	Jan 2019 to Jun 2019	2,000 bbl/d	US$62.85/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	2,000 bbl/d	US$75.00/US$61.70/US$49.00	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$78.00/US$73.00/US$63.00	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
Basis Swap [3]	Mar 2019 to Jun 2019	2,000 bbl/d	WTI less US$14.75/bbl	WCS
Basis Swap [3]	Apr 2019 to Jun 2019	2,000 bbl/d	WTI less US$13.65/bbl	WCS
Basis Swap [3]	Jul 2019 to Sep 2019	4,000 bbl/d	WTI less US$17.38/bbl	WCS
Basis Swap [3]	Oct 2019 to Dec 2019	4,000 bbl/d	WTI less US$20.88/bbl	WCS
Natural Gas				
Fixed - Sell	Jan 2019 to Mar 2019	5,000 GJ/d	CAD$2.25	AECO
Fixed - Sell	Jan 2019 to Dec 2019	5,000 mmbtu/d	US$3.15	NYMEX
Fixed - Sell	Jan 2019 to Mar 2019	10,000 mmbtu/d	US$3.82	NYMEX
Fixed - Sell	Apr 2019 to Jun 2019	10,000 mmbtu/d	US$2.79	NYMEX
Fixed - Sell	Jul 2019 to Sep 2019	10,000 mmbtu/d	US$2.79	NYMEX
Fixed - Sell	Oct 2019 to Dec 2019	10,000 mmbtu/d	US$2.88	NYMEX

(1) Based on the weighted average price per unit for the period.
(2) Producer 3-way option consists of a sold call, a bought put and a sold put. To illustrate, in a US$70.00/US$60.00/US$50.00 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$60.00/bbl when WTI is between US$50.00/bbl and US$60.00/bbl; Baytex receives the market price when WTI is between US$60.00/bbl and US$70.00/bbl; and Baytex receives US$70.00/bbl when WTI is above US$70.00/bbl.
(3) Contracts entered subsequent to December 31, 2018.

Interest Rate Swap

The following interest rate swap contract was assumed as part of the Strategic Combination and was outstanding as at March 5, 2019.

Contract Type	Notional Amount	Maturity Date	Fixed Contract Price	Reference[1]
Interest rate swap	$100 million	October 2020	2.02%	CDOR

(1) Canadian Dollar Offered Rate.

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 March 5, 2019, Baytex had committed to deliver the following volumes of raw bitumen to market on rail.

Period	Volume
Jan 2019 to Oct 2019	1,000 bbl/d
Jan 2019 to Dec 2019	5,000 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 years ended December 31, 2018 and 2017.

	Years Ended December 31					
	2018			2017		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**43,382**	**37,076**	**80,458**	33,564	36,678	70,242
Operating netback:						
Total sales, net of blending and other expense	**$ 34.76**	**$ 59.83**	**$ 46.31**	$ 34.22	$ 46.41	$ 40.58
Royalties	**(4.59)**	**(17.81)**	**(10.68)**	(4.79)	(13.69)	(9.43)
Operating expense	**(14.00)**	**(6.64)**	**(10.61)**	(14.86)	(6.52)	(10.50)
Transportation expense	**(2.33)**	**—**	**(1.26)**	(2.77)	—	(1.33)
Operating netback	**$ 13.84**	**$ 35.38**	**$ 23.76**	$ 11.80	$ 26.20	$ 19.32
Realized financial derivatives (loss) gain	**—**	**—**	**(2.49)**	—	—	0.30
Operating netback after financial derivatives	**$ 13.84**	**$ 35.38**	**$ 21.27**	$ 11.80	$ 26.20	$ 19.62

Operating netback after financial derivatives of $21.27/boe increased $1.65/boe or 8% from $19.62/boe for 2017. Higher U.S. oil prices increased our U.S. and overall realized sales price which was partially offset by higher royalties and slightly higher operating expenses compared to 2017. The increase in royalty expense per boe is due to higher realized prices in 2018 as our royalty rate of 23.1% was consistent with 23.2% in 2017. Operating expense per boe was slightly higher in 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 $2.49/boe in 2018 as losses recorded on our WTI and Brent contracts were partially offset by gains recorded on our WCS differential and natural gas contracts.

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 expenses for the years ended December 31, 2018 and 2017.

	Years Ended December 31		
($ thousands except for per boe)	**2018**	2017	Change
Gross general and administrative expense	**$ 56,318**	$ 54,349	$ 1,969
Overhead recoveries	**(10,493)**	(6,960)	(3,533)
General and administrative expense	**$ 45,825**	$ 47,389	$ (1,564)
General and administrative expense per boe	**$ 1.56**	$ 1.85	$ (0.29)

We reported G&A expense of $45.8 million ($1.56/boe) for 2018 which is $1.6 million ($0.29/boe) lower than $47.4 million ($1.85/boe) for 2017. Gross G&A expense of $56.3 million in 2018 was relatively consistent with $54.3 million in 2017 despite the additional staff and G&A expense associated with the Strategic Combination. Overhead recoveries of $10.5 million were $3.5 million higher than 2018 as our operated exploration and development program in Canada was higher relative to 2017.

Our 2019 guidance for G&A expense is $44.0 million ($1.27/boe based on the midpoint of our production guidance) compared to $45.8 million ($1.56/boe) in 2018. The decrease in per unit costs is associated with higher production anticipated in 2019 relative to 2018. Total G&A of $44.0 million for 2019 is slightly down from $45.8 million for 2018 despite the additional staff and G&A expense associated with the Strategic Combination along with changes in accounting for certain leases which will not be included in G&A expense in 2019.

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.

	Year Ended December 31		
($ thousands except for per boe)	**2018**	2017	Change
Interest on bank loan	**$ 15,637**	$ 11,439	$ 4,198
Interest on long-term notes	**88,681**	89,043	(362)
Cash interest	**104,318**	100,482	3,836
Accretion of debt issue costs	**3,854**	4,474	(620)
Accretion of asset retirement obligation	**10,914**	8,682	2,232
Financing and interest expense	**$ 119,086**	$ 113,638	$ 5,448
Cash interest per boe	**$ 3.55**	$ 3.92	$ (0.37)
Financing and interest expense per boe	**$ 4.06**	$ 4.43	$ (0.37)

Financing and interest expense was $119.1 million for 2018 which is $5.4 million higher than $113.6 million reported for 2017. Interest on our bank loan of $15.6 million in 2018 increased $4.2 million relative to $11.4 million in 2017 due to the increase in loan balances following the assumption of debt associated with the Strategic Combination. The weighted average interest rate on the credit facilities for 2018 was 4.3% as compared to 4.1% for 2017. The interest reported on our long-term notes is consistent in 2018 and 2017 as the exchange rate used to convert the reported interest on our U.S. dollar denominated notes was relatively consistent during both periods. Total accretion was higher in 2018 as our asset retirement obligation increased with the Strategic Combination and the discount rate used to present value our asset retirement obligation was lower relative to 2017.

We expect cash interest of approximately $112 million in 2019 compared to $104.3 million in 2018. The expected increase in cash interest reflects the increase in bank debt associated with the Strategic Combination.

Exploration and Evaluation Expense

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the derecognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of lease expiries, the accumulated costs of expiring leases, and the economic facts and circumstances related to the Company's exploration programs. E&E expense was $21.7 million for 2018 compared to $8.3 million for 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 years ended December 31, 2018 and 2017.

	Years Ended December 31		
($ thousands except for per boe)	**2018**	2017	Change
Depletion	**$ 556,634**	$ 480,082	$ 76,552
Depreciation	**2,050**	1,847	203
Depletion and depreciation	**$ 558,684**	$ 481,929	$ 76,755
Depletion and depreciation per boe	**$ 19.02**	$ 18.80	$ 0.22

Depletion and depreciation expense was $558.7 million ($19.02/boe) for 2018 compared to $481.9 million ($18.80/boe) reported for 2017. Total depletion and depreciation expense was higher in 2018 due to the Strategic Combination which resulted in a higher depletable base and production relative to 2017. Our depletion rate was lower in 2018, prior to the Strategic Combination, due to an increase in proved plus probable reserves recorded in Q4/2017 at a lower cost than our depletion rate. The depletion rate increased following the Strategic Combination in 2018 due to the addition of proved plus probable reserves at a higher cost than our depletion rate and resulted in the depletion rate of $19.02/boe for 2018 which was slightly higher than $18.80/boe for 2017.

Impairment

In 2018 we identified indicators of impairment and calculated the recoverable amount of our Conventional CGU and our Eagle Ford CGU. The recoverable amount was not sufficient to cover the carrying amount of either CGU and we recorded total impairments of $285.3 million for 2018. We recorded a $65.0 million write-down on our Conventional assets in Canada due to a sustained decline in natural gas prices and a reduction in planned exploration and development expenditures on these assets. We also recorded a $220.3 million impairment in our Eagle Ford CGU in 2018 as the rate of future development outlined by the operator was reduced and resulted in a decline in the net present value of our proved plus probable reserves with no significant changes to proved plus probable reserves volumes. We did not identify any indicators of impairment or impairment reversals on our remaining CGUs.

In 2017, we did not identify any indicators of impairment or impairment reversals on any of our cash generating units ("CGU") and therefore did not record any impairment expense or reversals of previously recorded impairments during the year ended December 31, 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.

As a result of the Strategic Combination, Baytex became the successor to Raging River's Share Awards Plan, 2012 Option Plan and 2016 Option Plan (collectively, the "Raging River Plans"). Although no new grants will be made under the Raging River Plans, share awards and options held under the Raging River Plans in existence at August 22, 2018 were converted to share awards and options to purchase shares in Baytex.

We recorded SBC expense of $19.5 million for 2018 which is up from $15.5 million reported for 2017. SBC expense is higher in 2018 due to $4.2 million of additional expense associated with share awards and options assumed from Raging River and share awards granted to former Raging River employees following closing of the Strategic Combination.

Foreign Exchange

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

		Years Ended December 31		
($ thousands except for exchange rates)		**2018**	2017	Change
Unrealized foreign exchange loss (gain)	**$**	**106,143**	$ (86,649)	$ 192,792
Realized foreign exchange loss (gain)		**2,151**	(411)	2,562
Foreign exchange loss (gain)	**$**	**108,294**	$ (87,060)	$ 195,354
CAD/USD exchange rates:				
At beginning of period		**1.2518**	1.3427	
At end of period		**1.3646**	1.2518	

We recorded an unrealized foreign exchange loss of $106.1 million for 2018 due to a weakening of the Canadian dollar relative to the U.S. dollar. The CAD/USD exchange rate was 1.3646 as at December 31, 2018 compared to 1.2518 as at December 31, 2017.

Realized foreign exchange gains and losses will fluctuate depending on the amount and timing of day-to-day U.S dollar denominated transactions for our Canadian operations. We recorded a realized foreign exchange loss of $2.2 million for the year ended December 31, 2018 compared to a gain of $0.4 million for 2017.

Income Taxes

		Years Ended December 31		
($ thousands)		**2018**	2017	Change
Current income tax recovery	**$**	**(35)**	$ (1,085)	$ 1,050
Deferred income tax recovery		**(101,732)**	(155,343)	53,611
Total income tax recovery	**$**	**(101,767)**	$ (156,428)	$ 54,661

Current income taxes were nominal for 2018 and 2017. During both of these years tax pool claims were sufficient to shelter the income associated with our adjusted funds flow.

We recorded a deferred income tax recovery of $101.7 million for 2018 compared to $155.3 million for 2017. The deferred tax recovery for 2018 includes a $63.4 million recovery associated with the impairment of oil and gas properties along with a $31.5 million expense associated with the gains on our financial derivatives. In 2017, the deferred tax recovery included a $91.8 million recovery related to U.S. tax reform enacted in December 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.

	December 31, 2018	December 31, 2017
Canadian Tax Pools		
Canadian oil and natural gas property expenditures	**$ 529,044**	$ 308,366
Canadian development expenditures	**765,289**	176,188
Canadian exploration expenditures	**8,875**	1,343
Undepreciated capital costs	**502,320**	228,739
Non-capital losses	**593,251**	337,808
Financing costs and other	**33,866**	46,986
Total Canadian tax pools	**$ 2,432,645**	$ 1,099,430

U.S. Tax Pools		
Depletion	**$ 180,367**	$ 183,406
Intangible drilling costs	**133,345**	204,857
Tangibles	**69,138**	108,631
Non-capital losses	**1,140,579**	1,140,673
Other	**407,654**	303,357
Total U.S. tax pools	**$ 1,931,083**	$ 1,940,924

Net Income (Loss) and Adjusted Funds Flow

The components of adjusted funds flow and net income or loss for the years ended December 31, 2018 and 2017 are set forth in the following table.

	Years Ended December 31		
($ thousands)	**2018**	2017	Change
Petroleum and natural gas sales	**$ 1,428,870**	$ 1,099,867	$ 329,003
Royalties	**(313,754)**	(241,892)	(71,862)
Revenue, net of royalties	**1,115,116**	857,975	257,141
Expenses			
Operating	**(311,592)**	(269,283)	(42,309)
Transportation	**(36,869)**	(33,985)	(2,884)
Blending and other	**(68,832)**	(59,345)	(9,487)
Operating netback	**$ 697,823**	$ 495,362	$ 202,461
General and administrative	**(45,825)**	(47,389)	1,564
Cash financing and interest	**(104,318)**	(100,482)	(3,836)
Realized financial derivatives (loss) gain	**(73,165)**	7,616	(80,781)
Realized foreign exchange (loss) gain	**(2,151)**	411	(2,562)
Other income (expense)	**1,172**	(2,216)	3,388
Current income tax recovery (expense)	**35**	1,085	(1,050)
Payments on onerous contracts	**(588)**	(6,746)	6,158
Adjusted funds flow	**$ 472,983**	$ 347,641	$ 125,342
Transaction costs	**(13,074)**	—	(13,074)
Exploration and evaluation	**(21,729)**	(8,253)	(13,476)
Depletion and depreciation	**(558,684)**	(481,929)	(76,755)
Share based compensation	**(19,534)**	(15,509)	(4,025)
Non-cash financing and accretion	**(14,768)**	(13,156)	(1,612)
Unrealized financial derivatives gain (loss)	**116,715**	(2,439)	119,154
Unrealized foreign exchange gain (loss)	**(106,143)**	86,649	(192,792)
Gain on disposition of oil and gas properties	**1,946**	12,081	(10,135)
Impairment	**(285,341)**	—	(285,341)
Deferred income tax recovery	**101,732**	155,343	(53,611)
Payments on onerous contracts	**588**	6,746	(6,158)
Net income (loss) for the period	**$ (325,309)**	$ 87,174	$ (412,483)

We generated adjusted funds flow of $473.0 million for 2018, an increase of $125.3 million from adjusted funds flow of $347.6 million reported for 2017. The increase in adjusted funds flow in 2018 was primarily due to higher operating netback which increased $202.5 million from 2017 due to higher commodity prices and production which increased revenues, partially offset by higher royalties, operating and transportation expenses. The increase in operating netback was offset by realized hedging losses of $73.2 million recorded in 2018 compared to hedging gains of $7.6 million in 2017.

In 2018 we reported a net loss of $325.3 million compared to net income of $87.2 million in 2017. Depletion and depreciation increased by $76.8 million in 2018 following the Strategic Combination. In 2018 we recorded an unrealized gain on financial derivatives of $116.7 million as compared to an unrealized loss of $2.4 million in 2017. The Canadian dollar weakened in 2018 which resulted in an unrealized foreign exchange loss of $106.1 million primarily associated with the remeasurement of our U.S. dollar denominated debt. We recorded an unrealized foreign exchange gain of $86.6 million in 2017 due to a strengthening of the Canadian dollar through 2017. The net loss for 2018 includes a $285.3 million impairment expense recorded in Q4/2018 due to a change in development plans for our oil and natural gas properties along with a sustained decline in natural gas prices.

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 $204.8 million foreign currency translation gain for 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. The CAD/USD exchange rate was 1.3646 as at December 31, 2018 compared to 1.2518 as at December 31, 2017.

Capital Expenditures

Capital expenditures for the years ended December 31, 2018 and 2017 are summarized as follows.

	Years Ended December 31					
	2018			2017		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 225,904**	**$ 178,665**	**$ 404,569**	$ 81,564	$ 199,849	$ 281,413
Facilities	**58,813**	**14,605**	**73,418**	27,097	11,990	39,087
Land, seismic and other	**17,400**	**334**	**17,734**	4,613	1,153	5,766
Total exploration and development	**$ 302,117**	**$ 193,604**	**$ 495,721**	$ 113,274	$ 212,992	$ 326,266
Acquisitions, net of proceeds from divestitures	**$ (1,818)**	**$ —**	**$ (1,818)**	$ 59,857	$ —	$ 59,857
Strategic Combination [1]	**$ 1,605,668**	**$ —**	**$ 1,605,668**	$ —	$ —	$ —

(1) Includes $1,239.0 million of consideration associated with 315.3 million common shares issued by Baytex at a closing share price of $3.93 per common share along with $3.1 million of share based compensation and assumed net debt of $363.6 million.

Exploration and development expenditures were $495.7 million for 2018 compared to $326.3 million for 2017. Our 2018 capital program includes $139.0 million of exploration and development expenditures for our Viking and Duvernay light oil properties subsequent to closing of the Strategic Combination.

In Canada, we invested $302.1 million on exploration and development activities in 2018 which is $188.8 million higher than $113.3 million in 2017. Exploration and development activity in 2018 includes 121 (83.0 net) wells drilled on our Viking lands and 4 (4.0 net) wells drilled on our Duvernay lands subsequent to closing the Strategic Combination. Our heavy oil drilling activities during 2018 includes 87 (62.9 net) wells drilled at Lloydminster and 12 (12.0 net) wells drilled at Peace River along with 8 (8.0 net) stratigraphic wells at Lloydminster and 1 (1.0 net) stratigraphic well at Peace River. Facilities expenditures of $58.8 million in 2018 includes construction of a gas plant and strategic infrastructure to support growth on our Peace River properties. Land, seismic and other expenditures of $17.4 million includes land expenditures to expand growth opportunities on our Duvernay and Viking properties.

Total U.S. exploration and development expenditures were $193.6 million for 2018, $19.4 million lower than $213.0 million for 2017. Lower exploration and development expenditures in 2018 are primarily a result of lower drilling and completion activity on our lands relative to 2017. During 2018 we participated in the drilling of 91 (20.8 net) wells and commenced production from 120 (26.2 net) wells compared to 140 (32.8 net) wells drilled and 115 (28.7 net) wells on production during 2017.

We completed minor acquisition and disposition activity in 2018 outside of the Strategic Combination which resulted in net proceeds of $1.8 million as compared to $59.9 million in 2017 which included the acquisition in Peace River for consideration of $66.1 million.

We expect to invest between $550 million and $650 million on exploration and development activities during 2019.

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain 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 December 31, 2018, our capital structure was comprised of shareholders' capital, long-term notes, working capital and our bank loan.

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

Management of debt levels is a priority for Baytex in order to sustain operations and support our plans for long-term growth. At December 31, 2018, net debt was $2,265.2 million, an increase of $530.9 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. A weaker Canadian dollar at December 31, 2018 also increased the reported amount of our U.S. denominated debt by $107.1 million relative to December 31, 2017.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio and available capacity under our credit facilities. At December 31, 2018, our net debt to adjusted funds flow ratio was 3.1, 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 December 31, 2018.

Bank Loan

At December 31, 2018, the principal amount of bank loan and letters of credit outstanding was $536.9 million and we had approximately $547.7 million of undrawn capacity under our credit facilities that total approximately $1,084.6 million. 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 also matures on June 4, 2020. We anticipate requesting an extension to our credit facilities during 2019.

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. 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 2018 was 4.3% as compared to 4.1% for 2017.

Financial Covenants

The following table summarizes the financial covenants applicable to the credit facilities and Baytex's compliance therewith as at December 31, 2018.

Covenant Description	Position as at December 31, 2018	Covenant
Senior Secured Debt(1) to Bank EBITDA(2) (Maximum Ratio)	**0.64:1.00**	3.50:1.00
Interest Coverage(3) (Minimum Ratio)	**8.00:1.00**	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 December 31, 2018, the Company's Senior Secured Debt totaled $536.9 million which includes $522.3 million of principal amounts outstanding and $14.6 million of letters of credit.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, unrealized gains and losses on financial derivatives, income tax, non-recurring losses, 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 December 31, 2018 was $833.7 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expense, 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 December 31, 2018 were $104.3 million.

Long-Term Notes

We have four series of long-term notes outstanding that total $1.60 billion as at December 31, 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 December 31, 2018, the fixed charge coverage ratio was 8.00:1.00.

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. These notes are redeemable at our option, in whole or in part, at par from February 17, 2019 to maturity.

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

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

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10.0 million preferred shares. The rights and terms of preferred shares are determined upon issuance. During the year ended December 31, 2018, we issued 3.3 million common shares pursuant to our share-based compensation program and 315.3 million common shares on closing of the Strategic Combination. As at March 5, 2019, we had 555.9 million common shares issued and outstanding and no preferred shares issued and outstanding.

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact our adjusted funds flow in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 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	**$ 258,114**	$ 258,114	$ —	$ —	$ —
Bank loan[(1) (2)]	**522,294**	—	522,294	—	—
Long-term notes[(2)]	**1,596,323**	—	750,503	300,000	545,820
Interest on long-term notes[(3)]	**334,028**	92,367	156,525	72,350	12,786
Operating leases	**22,745**	7,484	12,492	2,753	16
Processing agreements	**47,717**	10,926	15,526	9,039	12,226
Transportation agreements	**112,002**	14,398	42,054	19,821	35,729
Total	**$ 2,893,223**	$ 383,289	$ 1,499,394	$ 403,963	$ 606,577

(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.

FOURTH QUARTER 2018 OPERATING AND FINANCIAL RESULTS

Our operating and financial results for Q4/2018 and Q4/2017 are summarized in the following table.

	Three Months Ended December 31							
	2018				2017			
($ thousands except for per boe)	**Canada**	**U.S.**	**Corporate**	**Total**	Canada	U.S.	Corporate	Total
Total production (boe/d)	**60,453**	**38,437**	**—**	**98,890**	32,194	37,362	—	69,556
Total sales, net of blending and other per boe	**$ 24.04**	**$ 59.66**	**$ —**	**$ 37.89**	$ 36.89	$ 51.53	$ —	$ 44.75
Royalties per boe	**(3.10)**	**(17.68)**	**—**	**(8.77)**	(5.72)	(15.30)	—	(10.86)
Operating expense per boe	**(13.42)**	**(6.56)**	**—**	**(10.76)**	(16.57)	(6.04)	—	(10.91)
Transportation expense per boe	**(1.98)**	**—**	**—**	**(1.21)**	(2.59)	—	—	(1.20)
Operating netback per boe	**$ 5.54**	**$ 35.42**	**$ —**	**$ 17.15**	$ 12.01	$ 30.19	$ —	$ 21.78
Financial								
Petroleum and natural gas sales	**$ 147,472**	**$ 210,965**	**$ —**	**$ 358,437**	$ 126,052	$ 177,111	$ —	$ 303,163
Royalties	**(17,229)**	**(62,536)**	**—**	**(79,765)**	(16,947)	(52,578)	—	(69,525)
Revenue, net of royalties	**130,243**	**148,429**	**—**	**278,672**	109,105	124,533	—	233,638
Operating expense	**(74,663)**	**(23,194)**	**—**	**(97,857)**	(49,086)	(20,751)	—	(69,837)
Transportation expense	**(10,994)**	**—**	**—**	**(10,994)**	(7,658)	—	—	(7,658)
Blending and other expense	**(13,755)**	**—**	**—**	**(13,755)**	(16,793)	—	—	(16,793)
Operating netback	**$ 30,831**	**$ 125,235**	**$ —**	**$ 156,066**	$ 35,568	$ 103,782	$ —	$ 139,350
Realized financial derivatives (loss) gain	**—**	**—**	**(3,063)**	**(3,063)**	—	—	1,898	1,898
General and administrative	**—**	**—**	**(14,096)**	**(14,096)**	—	—	(9,717)	(9,717)
Cash interest	**—**	**—**	**(27,933)**	**(27,933)**	—	—	(24,849)	(24,849)
Other	**—**	**—**	**(146)**	**(146)**	(1,367)	963	(482)	(886)
Adjusted funds flow	**$ 30,831**	**$ 125,235**	**$ (45,238)**	**$ 110,828**	$ 34,201	$ 104,745	$ (33,150)	$ 105,796
Transaction costs	**(8)**	**—**	**—**	**(8)**	—	—	—	—
Exploration and evaluation	**(6,693)**	**(11,149)**	**—**	**(17,842)**	(2,748)	—	—	(2,748)
Depletion and depreciation	**(122,483)**	**(69,497)**	**(2,050)**	**(194,030)**	(45,757)	(64,930)	(86)	(110,773)
Share based compensation	**—**	**—**	**(4,524)**	**(4,524)**	—	—	(2,898)	(2,898)
Non-cash financing and accretion	**—**	**—**	**(4,328)**	**(4,328)**	—	—	(3,492)	(3,492)
Unrealized financial derivatives gain (loss)	**—**	**—**	**181,856**	**181,856**	—	—	(30,137)	(30,137)
Unrealized foreign exchange loss	**—**	**—**	**(68,007)**	**(68,007)**	—	—	(740)	(740)
Gain on disposition of oil and gas properties	**182**	**—**	**—**	**182**	18,673	—	—	18,673
Impairment	**(65,000)**	**(220,341)**	**—**	**(285,341)**	—	—	—	—
Deferred income tax recovery (expense)	**40,526**	**42,000**	**(32,699)**	**49,827**	(3,468)	88,301	16,284	101,117
Payments on onerous contracts	**—**	**—**	**149**	**149**	—	—	1,240	1,240
Net income (loss)	**$(122,645)**	**$(133,752)**	**$ 25,159**	**$(231,238)**	$ 901	$ 128,116	$ (52,979)	$ 76,038
Exploration and development expenditures								
Drilling, completion and equipping	**$ 103,230**	**$ 55,197**	**$ —**	**$ 158,427**	$ 24,627	$ 45,238	$ —	$ 69,865
Facilities	**12,339**	**3,388**	**—**	**15,727**	15,264	3,054	—	18,318
Land, seismic and other	**9,938**	**70**	**—**	**10,008**	1,973	—	—	1,973
Exploration and development expenditures	**$ 125,507**	**$ 58,655**	**$ —**	**$ 184,162**	$ 41,864	$ 48,292	$ —	$ 90,156
Acquisitions, net of proceeds from divestitures	**$ 183**	**$ —**	**$ —**	**$ 183**	$ (3,937)	$ —	$ —	$ (3,937)

The following table compares selected benchmark prices for Q4/2018 and Q4/2017.

	Three Months Ended December 31		
	2018	2017	Change
Benchmark Averages			
WTI oil (US$/bbl)[(1)]	**58.81**	55.40	3.41
WCS heavy oil differential to WTI (US$/bbl)	**(39.42)**	(12.26)	(27.16)
WCS heavy oil (CAD$/bbl)[(2)]	**25.62**	54.86	(29.24)
LLS oil differential to WTI (US$/bbl)	**7.83**	5.10	2.73
LLS oil (US$/bbl)[(3)]	**66.64**	60.50	6.14
Edmonton par oil differential to WTI ($/bbl)	**(26.51)**	(1.13)	(25.39)
Edmonton par oil ($/bbl)	**42.68**	69.02	(26.34)
CAD/USD average exchange rate	**1.3215**	1.2717	0.0498
AECO natural gas price ($/mcf)[(4)]	**1.94**	1.96	(0.02)
NYMEX natural gas price (US$/mmbtu)[(5)]	**3.64**	2.93	0.71

(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.

Our operating and financial results for Q4/2018 were impacted by a significant widening of Canadian light and heavy oil differentials in late 2018. Production of 98,890 boe/d was 29,334 boe/d or 42% higher than 69,556 boe/d for Q4/2017, reflecting the production contribution from the Strategic Combination combined with strong well results in the U.S. and Canada. Total exploration and development expenditures were $184.2 million and adjusted funds flow was $110.8 million in Q4/2018 which reflects the impact of volatile commodity prices along with shut-in and deferred production.

In the U.S., production of 38,437 boe/d for Q4/2018 was 1,075 boe/d or 3% higher than 37,362 boe/d reported for Q4/2017. Strong initial production results combined with slightly higher completion activity contributed to the increase in average daily production relative to Q4/2017. Our realized price of $59.66/boe was $8.13/boe or 16% higher than $51.53/boe reported for the same period of 2017. The increase in our realized price reflects higher U.S. crude oil pricing in Q4/2018 when the LLS benchmark price averaged US$66.64/bbl which is US$6.14/boe or 10% higher than US$60.50/bbl during Q4/2017. Operating netback of $125.2 million ($35.41/boe) was $21.5 million ($5.22/boe) higher than $103.8 million ($30.19/boe) for Q4/2017 primarily due to higher average daily production combined with the increase in realized pricing. Exploration and development expenditures of $58.7 million in Q4/2018 includes costs associated with drilling 19 (3.3 net) wells and commencing production from 31 (5.9 net) wells. The increase in exploration development expenditures in Q4/2018 is a result of a weaker Canadian dollar combined with higher completion activity relative to Q4/2017 when we drilled 37 (7.6 net) wells and brought 25 (5.4 net) wells on production.

In Canada, production averaged 60,453 boe/d in Q4/2018 which is 28,259 boe/d or 88% higher than 32,194 boe/d reported for Q4/2017. The increase in production is primarily a result of the production contribution of 26,034 boe/d from the Strategic Combination which closed during Q3/2018 along with higher Canadian heavy oil production in Q4/2018. The decrease in our weighted average realized price of $24.04/boe for Q4/2018 was impacted by a significant widening of light and heavy oil differentials relative to Q4/2017 when our weighted average realized price was $36.89/boe. Due to a continued lack of egress and market access in Western Canada, the Edmonton Par benchmark price traded at a US$26.51/bbl discount to WTI while the WCS differential was a US$39.42/bbl discount to WTI in Q4/2018. This represents a widening of US$25.39/bbl and US$27.16/bbl, respectively, relative to Q4/2017 when the Edmonton par benchmark traded at a US$1.13/bbl discount to WTI and the WCS heavy oil differential was US$12.26/bbl. Operating netback of $30.8 million ($5.54/boe) for Q4/2018 is $4.7 million ($6.47/boe) lower than $35.6 million ($12.01/boe) reported for the same period of 2017. Exploration and development expenditures of $125.5 million in Q4/2018 includes drilling and completion costs associated with 98 (71.5 net) wells compared to 26 (13.4 net) wells in Q4/2017.

We generated adjusted funds flow of $110.8 million in Q4/2018 which is $5.0 million higher than $105.8 million in Q4/2017. The increase was driven by higher average daily production of 98,890 boe/d in Q4/2018 which is 29,334 boe/d or 42% higher than 69,556 boe/d for Q4/2017 primarily due to the Strategic Combination. The increase in average daily production in Q4/2018 was partially offset by a $4.63/boe or 21% decrease in operating netback per boe due to lower realized pricing relative to Q4/2017. The decrease in realized pricing in Q4/2018 reflects the significant decline in market prices for Canadian crude oil relative to Q4/2017. The $16.7 million increase in operating netback in Q4/2018 compared to Q4/2017 was reduced by higher G&A expense, interest expense, and hedging losses. G&A expense of $14.1 million in Q4/2018 includes $4.1 million of non-recurring costs associated with staffing reductions and resulted in a $4.4 million increase in G&A expense relative to $9.7 million for Q4/2017. Interest expense of $27.9 million in Q4/2018 was $3.1 million higher than $24.8 million for Q4/2017 as a result of the assumption of $363.6 million of net debt as part of the Strategic Combination. We recorded hedging losses of $3.1 million in Q4/2018 compared to hedging gains of $1.9 million in Q4/2017.

We recorded a net loss of $231.2 million in Q4/2018 compared to net income of $76.0 million in Q4/2017. Depletion and depreciation expense for Q4/2018 increased $83.3 million relative to Q4/2017 due to the additional depletion associated with the Strategic Combination. In Q4/2018 we recorded unrealized gains on financial derivatives of $181.9 million compared to unrealized losses of $30.1 million in Q4/2017. A weakening of the Canadian dollar during Q4/2018 resulted in a $68.0 million unrealized foreign exchange loss associated with the remeasurement of our U.S. dollar denominated debt. Our deferred income tax recovery for Q4/2018 was $51.3 million lower than Q4/2017 which included a $91.8 million recovery associated with U.S tax reform enacted in December 2017. The net loss for Q4/2018 includes a $285.3 million impairment expense recorded in Q4/2018 due to a change in development plans for our oil and natural gas properties. There was no impairment recorded in Q4/2017 as we did not identify any indicators of impairment or impairment reversal on our CGUs.

QUARTERLY FINANCIAL INFORMATION

	2018				2017			
($ thousands, except per common share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	**358,437**	436,761	347,605	286,067	303,163	258,620	277,536	260,549
Net income (loss)	**(231,238)**	27,412	(58,761)	(62,722)	76,038	(9,228)	9,268	11,096
Per common share - basic	**(0.42)**	0.07	(0.25)	(0.27)	0.32	(0.04)	0.04	0.05
Per common share - diluted	**(0.42)**	0.07	(0.25)	(0.27)	0.32	(0.04)	0.04	0.05
Adjusted funds flow	**110,828**	171,210	106,690	84,255	105,796	77,340	83,136	81,369
Per common share - basic	**0.20**	0.46	0.45	0.36	0.45	0.33	0.35	0.35
Per common share - diluted	**0.20**	0.45	0.45	0.36	0.44	0.33	0.35	0.34
Exploration and development	**184,162**	139,195	78,830	93,534	90,156	61,544	78,007	96,559
Canada	**125,507**	94,477	30,608	51,525	41,864	14,487	18,439	38,484
U.S.	**58,655**	44,718	48,222	42,009	48,292	47,057	59,568	58,075
Acquisitions, net of divestitures	**183**	46	(21)	(2,026)	(3,937)	(7,436)	5,226	66,004
Net debt	**2,265,167**	2,112,090	1,784,835	1,783,379	1,734,284	1,748,805	1,819,387	1,850,909
Total assets	**6,377,198**	6,491,303	4,476,906	4,433,074	4,372,111	4,353,637	4,582,049	4,702,423
Common shares outstanding	**554,060**	553,950	236,662	236,578	235,451	235,451	234,204	234,203
Daily production								
Total production (boe/d)	**98,890**	82,412	70,664	69,522	69,556	69,310	72,812	69,298
Canada (boe/d)	**60,453**	45,214	34,042	33,505	32,194	34,560	34,284	33,217
U.S. (boe/d)	**38,437**	37,198	36,622	36,017	37,362	34,750	38,528	36,081
Benchmark prices								
WTI oil (US$/bbl)	**58.81**	69.50	67.88	62.87	55.40	48.20	48.28	51.91
WCS heavy (US$/bbl)	**19.39**	47.25	48.61	38.59	43.14	38.26	37.16	37.34
CAD/USD avg exchange rate	**1.3215**	1.3070	1.2911	1.2651	1.2717	1.2524	1.3447	1.3229
AECO gas ($/mcf)	**1.94**	1.35	1.03	1.85	1.96	2.04	2.77	2.94
NYMEX gas (US$/mmbtu)	**3.64**	2.90	2.80	3.00	2.93	3.00	3.18	3.32
Sales price ($/boe)	**37.89**	55.03	51.22	42.96	44.75	38.04	39.41	40.16
Royalties ($/boe)	**(8.77)**	(12.13)	(12.01)	(10.36)	(10.86)	(8.65)	(9.06)	(9.17)
Operating expense ($/boe)	**(10.76)**	(10.25)	(10.91)	(10.53)	(10.91)	(10.10)	(10.70)	(10.28)
Transportation expense ($/boe)	**(1.21)**	(1.26)	(1.22)	(1.36)	(1.20)	(1.46)	(1.35)	(1.29)
Operating netback ($/boe)	**17.15**	31.39	27.08	20.71	21.78	17.83	18.30	19.42
Financial derivatives gain (loss) ($/boe)	**(0.34)**	(4.07)	(4.57)	(1.57)	0.30	0.44	0.40	0.04
Operating netback after financial derivatives ($/boe)	**16.81**	27.32	22.51	19.14	22.08	18.27	18.70	19.46

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 resulted in the WTI benchmark gradually increasing from US$51.91/bbl in Q4/2016 to US$69.50/bbl during Q3/2018 before global geopolitical factors caused a decline to $58.81/bbl in Q4/2018. 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 2018. The increased level of activity along with the Strategic Combination in Q3/2018 has increased production from Q1/2017 into Q4/2018. 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 began to improve in late 2017 as commodity prices recovered and increased through Q3/2018 with higher production due to strong well performance along with the Strategic Combination. Adjusted funds flow was impacted by a significant widening of Canadian oil differentials in Q4/2018.

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 $1,850.9 million at Q1/2017 to $2,265.2 million at Q4/2018 primarily due to the additional net debt of $363.6 million assumed in conjunction with the Strategic Combination in Q3/2018.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at December 31, 2018, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information available to the Company at the time of financial statement preparation. Actual results can differ from those estimates as the effect of future events cannot be determined with certainty. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, and expenses are discussed below.

Reserves

The Company uses estimates of oil, natural gas and natural gas liquids ("NGLs") reserves in the calculation of depletion and in the determination of fair value estimates for non-financial assets. The estimation of reserves is a complex process requiring significant judgment. Estimates of the Company's reserves are reviewed annually by independent reserves evaluators and represent the estimated recoverable quantities of crude oil, natural gas and NGLs and the related net cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and the Canadian Oil and Gas Evaluation Handbook.

Estimates of economically recoverable oil, natural gas and NGLs and their future net cash flows are based on a number of variable factors and assumptions. Changes to estimates and assumptions such as forward price forecasts, production rates, ultimate reserve recovery, timing and amount of capital expenditures, production costs, marketability of oil and natural gas, royalty rates and other geological, economic and technical factors could have a significant impact on reported reserves. Changes in the Company's reserves estimates can have a significant impact on the carrying values of the Company's oil and gas properties, the calculation of depletion, the timing of cash flows for asset retirement obligations, asset impairments and estimates of fair value determined in accounting for business combinations.

Cash-generating Units ("CGUs")

The Company's oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash flows that are largely independent of the cash flows from other assets or groups of assets. The aggregation of assets in CGUs requires management judgment and is based on geographical proximity, shared infrastructure and similar exposure to market risk.

Identification of Impairment and Impairment Reversal Indicators

Judgment is required to assess when indicators of impairment or impairment reversal exist and when a calculation of the recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication of impairment or impairment reversal. When completing this assessment, management considers internal and external sources of information including changes in future commodity prices, changes in industry regulations or royalty rates, asset performance and changes in the Company's estimates of economically recoverable reserves.

Measurement of Recoverable Amount

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including estimates of reserve quantities, the discount rates used to present value future cash flows, future commodity prices, assumptions regarding the timing and amount of future expenditures and future abandonment and reclamation obligations. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets.

Exploration and Evaluation ("E&E") Assets

Costs associated with acquiring oil and natural gas licenses and exploratory drilling are accumulated as E&E assets pending determination of technical feasibility and commercial viability. The determination of technical feasibility and commercial viability of E&E assets for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment. Management uses the establishment of commercial reserves as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets are tested for impairment and reclassified to oil and natural gas properties.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the assets acquired meet the definition of a business in accordance with IFRS. The determination of fair value assigned to assets acquired and liabilities assumed often requires management to make assumptions and estimates about future events. The assumptions and estimates with respect to determining the fair value of oil and gas properties and E&E assets acquired include estimates of reserves acquired, forecast benchmark commodity prices and discount rates used to present value future cash flows. Changes in any of the assumptions or estimates used in determining the fair value of assets acquired and liabilities assumed could impact the amounts assigned to assets, liabilities and goodwill.

Joint Arrangements

Judgment is required to determine when the Company has joint control over an arrangement. In establishing joint control, management considers whether the decisions regarding the capital and operating activities of the arrangement require unanimous consent.

Classification of a joint arrangement once joint control has been established also requires judgment. The type of joint arrangement is determined by assessing the rights and obligations arising from the arrangement given the structure, legal form, and terms agreed upon by the parties sharing control. Arrangements where the controlling parties have rights to the net assets of the arrangement are classified as joint ventures. Arrangements where the controlling parties have rights to the assets and revenues, and obligations for the liabilities and expenses, are classified as joint operations. Baytex does not have any joint arrangements that are structured through joint venture arrangements.

Financial Derivatives

Financial derivatives are measured at fair value on each reporting date. The Company uses estimates of future commodity prices and interest rates available at period end to determine the fair value of outstanding financial derivatives. Changes in market pricing between period end and settlement of the derivative contracts could have a significant impact on financial results related to the financial derivatives.

Asset Retirement Obligations

The Company's provision for asset retirement obligations is based on estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future, and discount and inflation rates. The provision for asset retirement obligations represents management's best estimate of the present value of the future abandonment and reclamation costs required under current regulatory requirements. Actual abandonment and reclamation costs could be materially different from estimated amounts.

Income Taxes

Regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. Interpretation and application of existing regulation and legislation requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes. Estimates of future income taxes are subject to measurement uncertainty.

CURRENT AND FUTURE CHANGES IN ACCOUNTING POLICIES

Changes in significant accounting policies

Revenue from contracts with customers

Baytex adopted IFRS 15 Revenue from Contracts with Customers with a date of initial application of January 1, 2018, using the retrospective method. Baytex recognizes revenue when control of the product transfers to the customer and collection is reasonably assured. 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. The standard also requires new disclosure, as to the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. Baytex analyzed its revenue streams and its contracts with customers on adoption.

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 to 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 13 to the consolidated financial statements.

Financial instruments

Baytex adopted IFRS 9 Financial Instruments, on January 1, 2018. The new standard includes three classifications for financial assets; measurement at amortized cost, fair value through profit or loss and fair value through comprehensive income. Under IFRS 9, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded through other comprehensive income or loss rather than net income or loss. The new standard also introduces a credit loss model for evaluating impairment of financial assets.

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. The table summarizes the change in classification categories for Baytex's financial assets and liabilities.

Financial Instrument	IAS 39 Classification	IFRS 9 Classification
Cash and cash equivalents	Fair value through profit or loss	Amortized cost
Trade and other receivables	Amortized cost	Amortized cost
Financial derivatives	Fair value through profit or loss	Fair value through profit or loss
Trade and other payables	Amortized cost	Amortized cost
Bank loan	Amortized cost	Amortized cost
Long-term notes	Amortized cost	Amortized cost

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. IFRS 16 is required to be adopted either retrospectively or using the modified retrospective approach. The Company will adopt IFRS 16 on January 1, 2019 using the modified retrospective method. The modified retrospective approach does not require restatement of prior period comparative financial information as the Company will record the cumulative effect of applying the standard as an increase to right of use assets with a corresponding increase to lease obligations. The Company is currently in the process of quantifying the impact of the contracts that fall within the scope of IFRS 16. The Company expects adjustments for its office lease and the related subleases, field office leases, certain vehicles and field equipment, however, the full extent of the impact has not yet been finalized.

NON-GAAP AND CAPITAL MEASUREMENT MEASURES

In this MD&A, we refer to certain capital management measures (such as adjusted funds flow, net debt, operating netback and Bank EBITDA) which do not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP"). While adjusted funds flow, exploration and development expenditures, net debt, operating netback and Bank EBITDA are commonly used in the oil and natural gas industry, our determination of these measures may not be comparable with calculations of similar measures presented by other reporting issuers. We believe that inclusion of these non-GAAP financial measures provide useful information to investors and shareholders when evaluating the financial results of the Company.

Adjusted Funds Flow

We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our operations on a continuing basis. Transaction costs associated with the Strategic Combination are excluded from adjusted funds flow as we consider the costs non-recurring and not reflective of our ability to generate adjusted funds flow on an ongoing basis.

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.

	Years Ended December 31	
($ thousands)	**2018**	2017
Cash flow from operating activities	**$ 485,322**	$ 325,208
Change in non-cash working capital	**(39,448)**	8,962
Asset retirement obligations settled	**14,035**	13,471
Transaction costs	**13,074**	—
Adjusted funds flow	**$ 472,983**	$ 347,641

Exploration and Development Expenditures

We use exploration and development expenditures to measure and evaluate the performance of our capital programs. The total amount of exploration and development expenditures is managed as part of our budgeting process and can vary from period to period depending on the availability of adjusted funds flow and other sources of liquidity. We eliminate changes in non-cash working capital, acquisition and dispositions, and additions to other plant and equipment from investing activities as these amounts are generated by activities outside of our programs to explore and develop our existing properties.

Changes in non-cash working capital are eliminated in the determination of exploration and development expenditures as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our operations on a continuing basis. Our capital budgeting process is focused on programs to explore and develop our existing properties, accordingly, cash flows arising from acquisition and disposition activities are eliminated as we analyze these activities on a transaction by transaction basis separately from our analysis of the performance of our capital programs. Additions to other plant and equipment is primarily comprised of expenditures on corporate assets which do not generate incremental oil and natural gas production and is therefore analyzed separately from our evaluation of the performance of our exploration and development programs.

The following table reconciles cash flow used in investing activities to exploration and development expenditures.

	Years Ended December 31	
($ thousands)	**2018**	2017
Cash flow used in investing activities	**$ 463,272**	$ 352,678
Change in non-cash working capital	**32,435**	33,683
Proceeds from dispositions	**2,519**	11,786
Property acquisitions	**(701)**	(71,643)
Additions to other plant and equipment	**(1,804)**	(238)
Exploration and development expenditures	**$ 495,721**	$ 326,266

Net Debt

We believe that net debt assists in providing a more complete understanding of our financial position and provides a key measure to assess our liquidity. We calculate net debt based on the principal amounts of our bank loan and long-term notes outstanding, including working capital. The current portion of financial derivatives is excluded as the valuation of the underlying contracts is subject to a high degree of volatility prior to the ultimate settlement. Onerous contracts are excluded from net debt as the underlying contracts do not represent an available source of liquidity. We use the principal amounts of the bank loan and long-term notes outstanding in the calculation of net debt as these amounts represent our ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the bank loan and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of liquidity or repayment obligation.

The following table summarizes our calculation of net debt.

($ thousands)	**December 31, 2018**	December 31, 2017
Bank loan[1]	**$ 522,294**	$ 213,376
Long-term notes[1]	**1,596,323**	1,489,210
Working capital (surplus) deficiency[2]	**146,550**	31,698
Net debt	**$ 2,265,167**	$ 1,734,284

(1) Principal amount of instruments expressed in Canadian dollars.
(2) Working capital is 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 expense, royalties, operating expense and transportation expense. Operating netback per boe is the operating netback divided by barrels of oil equivalent production volume for the applicable period. We believe that this measure assists in assessing our ability to generate cash margin on a unit of production basis and is a key measure used to evaluate our operating performance.

	Years Ended December 31	
($ thousands)	**2018**	2017
Petroleum and natural gas sales	**$ 1,428,870**	$ 1,099,867
Blending and other expense	**(68,832)**	(59,345)
Total sales, net of blending and other expense	**1,360,038**	1,040,522
Royalties	**(313,754)**	(241,892)
Operating expense	**(311,592)**	(269,283)
Transportation expense	**(36,869)**	(33,985)
Operating netback	**697,823**	495,362
Realized financial derivative (loss) gain	**(73,165)**	7,616
Operating netback after realized financial derivatives	**$ 624,658**	$ 502,978

Bank EBITDA

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

	Years Ended December 31	
($ thousands)	**2018**	2017
Net income (loss)	**$ (325,309)**	$ 87,174
Plus:		
Financing and interest	**119,086**	113,638
Unrealized foreign exchange loss (gain)	**106,143**	(86,649)
Unrealized financial derivatives loss (gain)	**(116,715)**	2,439
Current income tax recovery	**(35)**	(1,085)
Deferred income tax recovery	**(101,732)**	(155,343)
Depletion and depreciation	**558,684**	481,929
Impairment	**285,341**	—
Gain on dispositions	**(1,946)**	(12,081)
Transaction costs	**13,074**	—
Non-cash items[(1)]	**41,263**	23,762
Adjustment for Strategic Combination [(2)]	**255,800**	—
Bank EBITDA	**$ 833,654**	$ 453,784

(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.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2018, an evaluation was conducted of the effectiveness of our “disclosure controls and procedures” (as defined in the United States by Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934 (the “Exchange Act”) and in Canada by National Instrument 52-109, Certification of Disclosure in Issuers' Annual and Interim Filings ("NI 52-109")) under the supervision of and with the participation of management, including the President and Chief Executive Officer and the Executive Vice President and Chief Financial Officer of Baytex (collectively the "certifying officers"). Based on that evaluation, the certifying officers concluded that our disclosure controls and procedures are effective to ensure that the information required to be disclosed in the reports that we file or submit under the Exchange Act or under Canadian securities legislation is (i) recorded, processed, summarized and reported within the time periods specified in the applicable rules and forms and (ii) accumulated and communicated to our management, including the certifying officers, to allow timely decisions regarding the required disclosure.

It should be noted that while the certifying officers believe that our disclosure control and procedures provide a reasonable level of assurance that they are effective, they do not expect that our disclosure controls and procedures will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute assurance that the objectives of the control system are met.

Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over the Company's financial reporting. Internal control over our financial reporting is a process designed under the supervision of and with the participation of management, including the certifying officers, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

Management has assessed the effectiveness of our "internal control over financial reporting" as defined in the Exchange Act and as defined by NI 52-109. The assessment was based on the framework in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Management concluded that our internal control over financial reporting was effective as of December 31, 2018.

In accordance with the provisions of NI 52-109 and consistent with SEC guidance, the scope of the evaluation did not include internal controls over financial reporting of Raging River. 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 year ended December 31, 2018, the assets previously held by Raging River contributed revenues, net of royalties of $142.3 million. At December 31, 2018, total assets of $2.1 billion were associated with the acquired entity.

The effectiveness of our internal control over financial reporting as of December 31, 2018 has been audited by KPMG LLP, as reflected in their report for 2018.

Changes in Internal Control over Financial Reporting

The Company's internal controls over financial reporting commencing August 22, 2018 include Raging River's systems, processes and controls, as well as additional controls designed to result in complete and accurate consolidation of Raging River's results. Other than Raging River, there has been no change in the Baytex's internal control over financial reporting that occurred during 2018 that has materially affected, or are reasonably likely to materially affect, Baytex's internal control over financial reporting.

SELECTED ANNUAL INFORMATION

The following table summarizes key annual financial and operating information over the three most recently completed financial years.

($ thousands, except per common share amounts)		**2018**		2017		2016
Revenues, net of royalties	**$**	**1,115,116**	$	857,975	$	601,979
Adjusted funds flow	**$**	**472,983**	$	347,641	$	276,251
Per common share - basic	**$**	**1.35**	$	1.48	$	1.30
Per common share - diluted	**$**	**1.35**	$	1.47	$	1.30
Net income (loss)	**$**	**(325,309)**	$	87,174	$	(485,184)
Per common share - basic	**$**	**(0.93)**	$	0.37	$	(2.29)
Per common share - diluted	**$**	**(0.93)**	$	0.37	$	(2.29)
Total assets	**$**	**6,377,198**	$	4,372,111	$	4,594,085
Bank loan - principal	**$**	**522,294**	$	213,376	$	191,286
Long term notes - principal	**$**	**1,596,323**	$	1,489,210	$	1,584,158
Average wellhead prices, net of blending costs ($/boe)	**$**	**46.31**	$	40.58	$	30.29
Total production (boe/d)		**80,458**		70,242		69,509

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; the percentage of production from the Raging River properties that is high operating netback light oil; our capital budget and expected average daily production for 2019; and our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2019; our expected price realizations for Canadian light oil; 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; the expected impact on total assets and total liabilities and net income before income tax of adopting IFRS 16 and our plan to complete an assessment of the controls, policies and procedures associated with Raging River by August 22, 2019. 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: the volatility of oil and natural gas prices and price differentials; availability and cost of gathering, processing and pipeline systems; failure to comply with the covenants in our debt agreements; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; risks associated with a third-party operating our Eagle Ford properties; the cost of developing and operating our assets; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2018, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2019 and in our other public filings.

The above summary of assumptions and risks related to forward-looking statements has been provided in order to provide shareholders and potential investors with a more complete perspective on Baytex's current and future operations and such information may not be appropriate for other purposes.

There is no representation by Baytex that actual results achieved will be the same in whole or in part as those referenced in the forward-looking statements and Baytex does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities law.

RISK FACTORS

We are focused on long-term strategic planning and have identified key risks, uncertainties and opportunities associated with our business that can impact the financial results. Listed below is a description of these risks and uncertainties. Further information regarding risks and uncertainties affecting our business is contained in our Annual Information Form for the year ended December 31, 2018 under the "Risk Factors" section.

Volatility of oil and natural gas prices and price differentials

Our financial condition is substantially dependent on, and highly sensitive to, the prevailing prices of crude oil and natural gas. Low prices for crude oil and natural gas produced by us could have a material adverse effect on our operations, financial condition and the value and amount of our reserves.

Prices for crude oil and natural gas fluctuate in response to changes in the supply of, and demand for, crude oil and natural gas, market uncertainty and a variety of additional factors beyond our control. Crude oil prices are primarily determined by international supply and demand. Factors which affect crude oil prices include the actions of OPEC, the condition of the Canadian, United States, European and Asian economies, government regulation, political stability in the Middle East and elsewhere, the supply of crude oil in North America and internationally, the ability to secure adequate transportation for products, the availability of alternate fuel sources and weather conditions. Natural gas prices realized by us are affected primarily in North America by supply and demand, weather conditions, industrial demand, prices of alternate sources of energy and developments related to the market for liquefied natural gas. All of these factors are beyond our control and can result in a high degree of price volatility. Fluctuations in currency exchange rates further compound this volatility when commodity prices, which are generally set in U.S. dollars, are stated in Canadian dollars.

Our financial performance also depends on revenues from the sale of commodities which differ in quality and location from underlying commodity prices quoted on financial exchanges. Of particular importance are the price differentials between our light/medium oil and heavy oil (in particular the light/heavy differential) and quoted market prices. Not only are these discounts influenced by regional supply and demand factors, they are also influenced by other factors such as transportation costs, capacity and interruptions, refining demand, the availability and cost of diluents used to blend and transport product and the quality of the oil produced, all of which are beyond our control. In addition, there is not sufficient pipeline capacity for Canadian crude oil to access the American refinery complex and the availability of additional transport capacity via rail is more expensive and variable, therefore, the price for Canadian crude oil is very sensitive to pipeline and refinery outages, which contributes to this volatility.

Decreases to or prolonged periods of low commodity prices, particularly for oil, may negatively impact our ability to meet guidance targets, maintain our business and meet all of our financial obligations as they come due. It could also result in the shut-in of currently producing wells without an equivalent decrease in expenses due to fixed costs, a delay or cancellation of existing or future drilling, development or construction programs, un-utilized long-term transportation commitments and a reduction in the value and amount of our reserves.

We conduct assessments of the carrying value of our assets in accordance with IFRS. If crude oil and natural gas forecast prices decline, the carrying value of our assets could be subject to downward revisions and our net earnings could be adversely affected.

Access to transportation capacity

We deliver our products through gathering, processing and pipeline systems which we do not own and purchasers of our products rely on third party infrastructure to deliver our products to market. The lack of access to capacity in any of the gathering, processing and pipeline systems could result in our inability to realize the full economic potential of our production or in a reduction of the price offered for our production. Alternately, a substantial decrease in the use of such systems can increase the cost we incur to use them. Any significant change in market factors or other conditions affecting these infrastructure systems and facilities, as well as any delays in constructing new infrastructure systems and facilities, could harm our business and, in turn, our financial condition.

Access to the pipeline capacity for the transport of crude oil into the United States has become inadequate for the amount of Canadian production being exported to the United States and has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price for crude oil. Although pipeline expansions are ongoing, the lack of pipeline capacity continues to affect the oil and natural gas industry in Canada and limit the ability to produce and to market oil and natural gas production. In addition, the pro-rationing of capacity on inter-provincial pipeline systems also continues to affect the ability to export oil and natural gas from Canada. There can be no certainty that investment in pipelines, which would result in additional long-term take-away capacity, will be made by applicable third party pipeline providers or that any requisite applications will receive regulatory approval. There is also no certainty that short-term operational constraints on pipeline systems, arising from pipeline interruption and/or increased supply of crude oil, will not occur.

There is no certainty that crude-by-rail transportation and other alternative types of transportation for our production will be sufficient to address any gaps caused by operational constraints on pipeline systems. In addition, our crude-by-rail shipments may be impacted by service delays, inclement weather or derailment and could adversely impact our crude oil sales volumes or the price received for our product. Crude oil produced and sold by us may be involved in a derailment or incident that results in legal liability or reputational harm.

A portion of our production may, from time to time, be processed through facilities controlled by third parties. From time to time these facilities may discontinue or decrease operations either as a result of normal servicing requirements or as a result of unexpected events. A discontinuance or decrease of operations could materially adversely affect our ability to process our production and to deliver the same for sale.

Debt covenant compliance

We are required to comply with the covenants in our credit facilities and long-term notes. If we fail to comply with our debt covenants, are unable to pay the debt service charges or otherwise commit an event of default, such as bankruptcy, it could result in the seizure and/or sale of our assets by our secured creditors. The proceeds from any sale of our assets would be applied to satisfy amounts owed to the secured creditors and then unsecured creditors. Only after the proceeds of that sale were applied towards our debt would the remainder, if any, be available for the benefit of our shareholders.

Access to capital markets

The future development of our business may be dependent on our ability to obtain additional capital including, but not limited to, debt and equity financing. Unpredictable financial markets and the associated credit impacts may impede our ability to secure and maintain cost effective financing and limit our ability to achieve timely access to capital markets on acceptable terms and conditions. If external sources of capital become limited or unavailable, our ability to make capital investments, continue our business plan, meet all of our financial obligations as they come due and maintain existing properties may be impaired. Should a lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued which could have a dilutive effect on Shareholders. Additionally, from time to time, we may issue Common Shares or other securities from treasury in order to reduce debt, complete acquisitions and/or optimize our capital structure.

Our ability to obtain additional capital is dependent on, among other things, a general interest in energy industry investments and, in particular, interest in our securities along with our ability to maintain our credit ratings. If we are unable to maintain our indebtedness and financial ratios at levels acceptable to our credit rating agencies, or should our business prospects deteriorate, our credit ratings could be downgraded, which would adversely affect the value of our outstanding securities and existing debt and our ability to obtain new financing and may increase our borrowing costs.

From time to time we may enter into transactions which may be financed in whole or in part with debt. The level of our indebtedness from time to time, could impair our ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Debt service and refinancing

Our existing credit facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our existing credit facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic term attractive to us, if at all. There can be no assurance that the amount of our credit facilities will be adequate for our future financial obligations, including future capital expenditures, or that we will be able to obtain additional funds. In the event we are unable to refinance our debt obligations, it may impact our ability to fund ongoing operations. In the event that the credit facilities are not extended before June 2020, indebtedness under the credit facilities will be repayable at that time. There is also a risk that the credit facilities will not be renewed for the same amount or on the same terms.

Non-operating agreements in the U.S.

Marathon Oil EF LLC ("Marathon Oil"), a wholly-owned subsidiary of Marathon Oil Corporation (NYSE: MRO), is the operator of our Eagle Ford acreage and we are reliant upon Marathon Oil to operate successfully. Marathon Oil will make decisions based on its own best interest and the collective best interest of all of the working interest owners of this acreage, which may not be in our best interest. We have a limited ability to exercise influence over the operational decisions of Marathon Oil, including the setting of capital expenditure budgets and determination of drilling locations and schedules. The success and timing of development activities, operated by Marathon Oil, will depend on a number of factors that will largely be outside of our control, including:

- the timing and amount of capital expenditures;
- Marathon Oil's expertise and financial resources;
- approval of other participants in drilling wells;
- selection of technology; and
- the rate of production of reserves, if any.

To the extent that the capital expenditure requirements related to our Eagle Ford acreage exceeds our budgeted amounts, it may reduce the amount of capital we have available to invest in our other assets. We have the ability to elect whether or not to participate in well locations proposed by Marathon Oil on an individual basis. If we elect to not participate in a well location, we forgo any revenue from such well until Marathon Oil has recouped, from our working interest share of production from such well, 300% to 500% of our working interest share of the cost of such operation.

Cost of development and operations

Our development and operating costs are affected by a number of factors including, but not limited to: price inflation; scheduling delays; trucking and fuel costs; failure to maintain quality construction standards; and supply chain disruptions, including access to skilled labour. Natural gas, electricity, water, diluent, chemicals, supplies, reclamation, abandonment and labour costs are examples of operating and other costs that are susceptible to significant fluctuation.

Reserves are a depleting resource

Our future oil and natural gas reserves and production, and therefore our cash flow, will be highly dependent on our success in exploiting our reserves base and acquiring additional reserves. The business of exploring for, developing or acquiring reserves is capital intensive. If external sources of capital become limited or unavailable on commercially reasonable terms, our ability to make the necessary capital investments to maintain or expand our oil and natural gas reserves may be impaired.

There is no assurance we will be successful in developing additional reserves or acquiring additional reserves at acceptable costs. Without these reserves additions, our reserves will deplete and as a consequence production from and the average reserves life of our properties will decline, which may result in a reduction in the value of our Common Shares.

Reserves

Our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas reserves. Future oil and natural gas exploration may involve unprofitable efforts, not only from unsuccessful wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit. Completion of a well does not assure a profit on the investment. Drilling hazards or environmental liabilities or damages could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays or failure in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees. New wells we drill or participate in may not become productive and we may not recover all or any portion of our investment in wells we drill or participate in.

Hydraulic fracturing

Hydraulic fracturing involves the injection of water, sand and small amounts of additives under pressure into rock formations to stimulate the production of oil and natural gas. Specifically, hydraulic fracturing enables the production of commercial quantities of oil and natural gas from reservoirs that were previously unproductive. Any new laws, regulations or permitting requirements regarding hydraulic fracturing could lead to operational delays, increased operating costs, third party or governmental claims, and could increase the Company's costs of compliance and doing business as well as delay the development of oil and natural gas resources from shale formations, which are not commercial without the use of hydraulic fracturing. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reserves.

Water use

The Company undertakes or intends to undertake certain hydraulic fracturing and waterflooding programs. To undertake such operations the Company needs to have access to sufficient volumes of water, or other liquids. There is no certainty that the Company will have access to the required volumes of water. In addition, in certain areas there may be restrictions on water use for activities such as hydraulic fracturing waterflooding. If the Company is unable to access such water it may not be able to undertake hydraulic fracturing or waterflooding activities, which may reduce the amount of oil and natural gas that the Company is ultimately able to produce from its reservoirs.

Government controls, legislation or regulation

The oil and gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation, and marketing) imposed by legislation enacted by various levels of government and, with respect to pricing and taxation of oil and natural gas, by agreements among the governments of Canada, Alberta, Saskatchewan, the United States and Texas, all of which should be carefully considered by investors in the oil and gas industry. All such controls, regulations and legislation are subject to revocation, amendment or administrative change, some of which have historically been material and in some cases materially adverse and there can be no assurance that there will not be further revocation, amendment or administrative change which will be materially adverse to our assets, reserves, financial condition, results of operations or prospects.

The oil and gas industry is also subject to regulation by governments in such matters as the awarding or acquisition of exploration and production rights, oil sands or other interests, the imposition of specific drilling obligations, environmental protection controls, control over the development and abandonment of fields (including restrictions on production) and possibly expropriation or cancellation of contract rights.

Other government controls, legislation or regulations may change from time to time in response to economic or political conditions. The exercise of discretion by governmental authorities under existing controls, legislation or regulations, the implementation of new controls, legislation or regulations or the modification of existing controls, legislation or regulations affecting the oil and gas industry could reduce demand for crude oil and natural gas, increase our costs, or delay or restrict our operations, all of which would have a material adverse effect on us. In addition, failure to comply with government controls, legislation or regulations may result in the suspension, curtailment or termination of operations and subject us to liabilities and administrative, civil and criminal penalties. Compliance costs can be significant.

Regulations regarding the disposal of fluids

The safe disposal of hydraulic fracturing fluids (including the additives) and water recovered from oil and natural gas wells is subject to ongoing regulatory review by the federal and provincial governments, including its effect on fresh water supplies and the ability of such water to be recycled, amongst other things. While it is difficult to predict the impact of any regulations that may be enacted in response to such review, the implementation of stricter regulations may increase the Company's costs of compliance.

Environmental, health and safety controls, legislation or regulations

All phases of our operations are subject to environmental, health and safety regulation pursuant to a variety of Canadian, U.S. and other federal, provincial, state and municipal laws and regulations (collectively, "**environmental regulations**") governing occupational health and safety aspects of our operations, the spill, release or emission of materials into the environment or otherwise relating to environmental protection. Environmental regulations require that wells, facility sites and other properties associated with our operations be constructed, operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. In addition, certain types of operations, including exploration and development projects and changes to certain existing projects, may require the submission and approval of environmental impact assessments or permit applications. Environmental regulations impose, among other things, restrictions, liabilities and obligations in connection with the generation, handling, use, storage, transportation, treatment and disposal of hazardous substances and waste and in connection with spills, releases and emissions of various substances to the environment. It also imposes restrictions, liabilities and obligations in connection with the management of fresh or potable water sources that are being used, or whose use is contemplated, in connection with oil and gas operations. The provinces of Alberta and Saskatchewan have developed liability management programs designed to prevent taxpayers from incurring costs associated with suspension, abandonment, remediation and reclamation of wells, facilities and pipelines in the event that a licensee or permit holder becomes defunct. These programs generally involve an assessment of the ratio of a licensee's deemed assets to deemed liabilities. If a licensee's deemed liabilities exceed its deemed assets, a security deposit is required. Changes in the ratio of our deemed assets to deemed liabilities or changes to the requirements of liability management programs may result in significant increases to the security that must be posted, the timing of our abandonment and reclamation operations and the costs associated with such operations.

Compliance with environmental regulations can require significant expenditures, including expenditures for clean-up costs and damages arising out of contaminated properties. Failure to comply with environmental regulations may result in the imposition of administrative, civil and criminal penalties or issuance of clean up orders in respect of us or our properties, some of which may be material. We may also be exposed to civil liability for environmental matters or for the conduct of third parties, including private parties commencing actions and new theories of liability, regardless of negligence or fault. Although it is not expected that the costs of complying with environmental regulations will have a material adverse effect on our financial condition or results of operations, no assurance can be made that the costs of complying with environmental regulations in the future will not have such an effect. The implementation of new environmental regulations or the modification of existing environmental regulations affecting the oil and gas industry generally could reduce demand for crude oil and natural gas, resulting in stricter standards and enforcement, larger penalties and liability and increased capital expenditures and operating costs, which could have a material adverse effect on our financial condition, results of operations or prospects. See "*Industry Conditions - Environmental and Occupational Safety and Health Regulation*".

In addition to regulatory requirements pertaining to the production, marketing and sale of oil and natural gas mentioned above, our business and financial condition could be influenced by federal legislation affecting, in particular, foreign investment, through legislation such as the *Competition Act* (Canada) and the *Investment Canada Act* (Canada).

Public perception and influence on the regulatory regime

Concern over the impact of oil and gas development on the environment and climate change has received considerable attention in the media and recent public commentary, and the social value proposition of resource development is being challenged. Additionally, certain pipeline leaks, major weather events and induced seismicity events have gained media, environmental and other stakeholder attention. Future laws and regulation may be impacted by such incidents, which could have a material adverse effect on our financial condition, results of operations or prospects.

Climate change initiatives

Our exploration and production facilities and other operational activities emit greenhouse gases ("**GHG**"). As such, it is highly likely that GHG emissions regulation (including carbon taxes) enacted in jurisdictions where we operate will impact us.

Negative consequences which could result from new GHG emissions regulation include, but are not limited to: increased operating costs; increased construction and development costs; additional monitoring and compliance costs; a requirement to redesign or retrofit current facilities; permitting delays; additional costs associated with the purchase of emission credits or allowances; and reduced demand for crude oil. Additionally, if GHG emissions regulation differs by region or type of production, all or part of our production could be subject to costs which are disproportionately higher than those of other producers.

The direct or indirect costs of compliance with GHG emissions regulation may have a material adverse affect on our business, financial condition, results of operations and prospects. At this time, it is not possible to predict whether compliance costs will have a material adverse affect on our business.

Although we provide for the necessary amounts in our annual capital budget to fund our currently estimated obligations, there can be no assurance that we will be able to satisfy our actual future obligations associated with GHG emissions from such funds. For more information on the evolution and status of climate change and related environmental legislation, see "*Industry Conditions - Climate Change Regulation*".

Interest rates and foreign exchange rates

There is a risk that the interest rates will increase given the current historical low level of interest rates. An increase in interest rates could result in a significant increase in the amount we pay to service debt and could have an adverse effect on our financial condition, results of operations and future growth, potentially resulting in a decrease to the market price of our Common Shares.

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the Canada/U.S. foreign exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar may negatively impact our revenues. A substantial portion of our operations and production are in the United States and, as such, we are exposed to foreign currency risk on both revenues and costs to the extent the value of the Canadian dollar decreases relative to the U.S. dollar. In addition, we are exposed to foreign currency risk as our credit facilities and a large portion of our long-term notes are denominated in U.S. dollars and the interest payable thereon is payable in U.S. dollars. Future Canada/U.S. foreign exchange rates could also impact the future value of our reserves as determined by our independent evaluator.

A decline in the value of the Canadian dollar relative to the United States dollar provides a competitive advantage to United States companies acquiring Canadian oil and gas properties and may make it more difficult for us to replace reserves through acquisitions.

Risk management

In response to fluctuations in commodity prices, foreign exchange and interest rates, we may utilize various derivative financial instruments and physical sales contracts to manage our exposure under a hedging program. The terms of these arrangements may limit the benefit to us of favourable changes in these factors, including receiving less than the market price for our production, and may also result in us paying royalties at a reference price which is higher than the hedged price. We may also suffer financial loss due to hedging arrangements if we are unable to produce oil or natural gas to fulfill our delivery obligations. There is also increased exposure to counterparty credit risk. To the extent that our current hedging agreements are beneficial to us, these benefits will only be realized for the period and for the commodity quantities in those contracts. In addition, there is no certainty that we will be able to obtain additional hedges at prices that have an equivalent benefit to us, which may adversely impact our revenues in future periods.

Income tax laws and other laws

We file all required income tax returns and believe that we are in full compliance with the applicable tax legislation. However, such returns are subject to audit and reassessment by the applicable taxation authority. Any such reassessment may have an impact on current and future taxes payable. At present, the Canadian tax authorities have reassessed the returns of certain of our subsidiaries.

Tax authorities having jurisdiction over us or our Shareholders may disagree with the manner in which we calculate our income for tax purposes or could change their administrative practices to our detriment or the detriment of our Shareholders. In addition, income tax laws and government incentive programs relating to the oil and gas industry may change in a manner that adversely affects the market price of the Common Shares.

Reserves Estimates

The reserves estimates included in this MD&A are estimates only. There are numerous uncertainties inherent in estimating quantities of reserves, including many factors beyond our control. In general, estimates of economically recoverable oil and natural gas reserves and the future net revenues therefrom are based upon a number of factors and assumptions made as of the date on which the reserves estimates were determined, such as geological and engineering estimates which have inherent uncertainties, the assumed effects of regulation by governmental agencies, historical production from the properties, initial production rates, production decline rates, the availability, proximity and capacity of oil and gas gathering systems, pipelines and processing facilities and estimates of future commodity prices and capital costs, all of which may vary considerably from actual results.

All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the price assumptions utilized in the reserve report, the present value of estimated future net revenues for our reserves and net asset value would be reduced and the reduction could be significant. Our actual production, revenues, royalties, taxes and development, abandonment and operating expenditures with respect to our reserves will likely vary from such estimates, and such variances could be material.

Estimates of reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves, rather than upon actual production history. Subsequent evaluation of the same reserves based upon production history will result in variations in the previously estimated reserves and such variances could be material.

Insurance

Our crude oil and natural gas operations are subject to all of the risks normally incidental to the: (i) storing, transporting, processing, refining and marketing of crude oil, natural gas and other related products; (ii) drilling and completion of crude oil and natural gas wells; and (iii) operation and development of crude oil and natural gas properties, including, but not limited to: encountering unexpected formations or pressures; premature declines of reservoir pressure or productivity; blowouts; fires; explosions; equipment failures and other accidents; gaseous leaks; uncontrollable or unauthorized flows of crude oil, natural gas or well fluids; migration of harmful substances; oil spills; corrosion; adverse weather conditions; pollution; acts of vandalism and terrorism; and other adverse risks to the environment.

Although we maintain insurance in accordance with customary industry practice, we are not fully insured against all of these risks nor are all such risks insurable and in certain circumstances we may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. In addition, the nature of these risks is such that liabilities could exceed policy limits, in which event we could incur significant costs that could have a material adverse effect on our business, financial condition, results of operations and prospects.

Credit risk

We are subject to the risk that counterparties to our risk management contracts, marketing arrangements and operating agreements and other suppliers of products and services may default on their obligations under such agreements or arrangements, including as a result of liquidity requirements or insolvency. Furthermore, low oil and natural gas prices increase the risk of bad debts related to our joint venture and industry partners. A failure by such counterparties to make payments or perform their operational or other obligations to us may adversely affect our results of operations, cash flows and financial position. Conversely, our counterparties may deem us to be at risk of defaulting on our contractual obligations. These counterparties may require that we provide additional credit assurances by prepaying anticipated expenses or posting letters of credit, which would decrease our available liquidity and increase our costs.

Additional business risks

Our business involves many operating risks related to acquiring, developing and exploring for oil and natural gas which even a combination of experience, knowledge and careful evaluation may not be able to overcome. Our operational risks include, but are not limited to: operational and safety considerations; pipeline transportation and interruptions; reservoir performance and technical challenges; partner risks; competition; technology; land claims; our ability to hire and retain necessary skilled personnel; the availability of drilling and related equipment; seasonality and access restrictions; timing and success of integrating the business and operations of acquired assets and companies; phased growth execution; risk of litigation, regulatory issues, increases in government taxes and changes to royalty or mineral/severance tax regimes; and risk to our reputation resulting from operational activities that may cause personal injury, property damage or environmental damage.

Large projects

We have a variety of exploration, development and construction projects underway at any given time. Project delays may result in delayed revenue receipts and cost overruns may result in projects being uneconomic. Our ability to complete projects is dependent on general business and market conditions as well as other factors beyond our control, including the availability of skilled labour and manpower, the availability and proximity of pipeline capacity and rail terminals, weather, environmental and regulatory matters, ability to access lands, availability of drilling and other equipment and supplies, and availability of processing capacity.

Thermal heavy oil projects

Our thermal heavy oil projects are capital intensive projects which rely on specialized production technologies. Certain current technologies for the recovery of heavy oil are energy intensive, requiring significant consumption of natural gas and other fuels in the production of steam that is used in the recovery process. The amount of steam required in the production process varies and therefore impacts costs. The performance of the reservoir can also affect the timing and levels of production using new technologies. A large increase in recovery costs could cause certain projects that rely on new technologies to become uneconomic, which could have an adverse effect on our financial condition. There are risks associated with growth and other capital projects that rely largely or partly on new technologies and the incorporation of such technologies into new or existing operations. The success of projects incorporating new technologies cannot be assured.

Project economics and our overall earnings may be reduced if increases in operating costs are incurred. Factors which could affect operating costs include, without limitation: labour costs; the cost of catalysts and chemicals; the cost of natural gas and electricity; water handling and availability; power outages; produced sand causing issues of erosion, hot spots and corrosion; reliability of facilities; maintenance costs; the cost to transport sales products; and the cost to dispose of certain by-products.

Demand for petroleum products

Conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas and technological advances in fuel economy and renewable energy could reduce demand for oil and natural gas. Certain jurisdictions have implemented policies or incentives to decrease the use of fossil fuels and encourage the use of renewable fuel alternatives, which may lessen demand for petroleum products and put downward pressure on commodity prices. In addition, advancements in energy efficient products have a similar affect on the demand for oil and gas products. The Company cannot predict the impact of changing demand for oil and natural gas products, and any major changes may have a material adverse effect on the Company's business and financial condition by decreasing its cash flows and the value of its assets.

Information technology risks

We utilize a number of information technology systems for the administration and management of our business. If our ability to access and use these systems is interrupted and cannot be quickly and easily restored then such event could have a material adverse effect on us. Furthermore, although our information technology systems are considered to be secure, if an unauthorized party is able to access the systems then such unauthorized access may compromise our business in a materially adverse manner.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2018, our internal control over financial reporting was effective. Management excluded from its design and assessment the internal control over financial reporting for Raging River Exploration Inc. (as permitted by applicable securities laws in Canada and the U.S.), which was acquired on August 22, 2018. The consolidated financial statements as at and for the year ended December 31, 2018 include $2.1 billion of total assets and $142.3 million of revenues, net of royalties from the acquired entity.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2018 has been audited by KPMG LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2018.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

Management, in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board, has prepared the accompanying consolidated financial statements of the Company. Financial and operating information presented throughout this Annual Report is consistent with that shown in the consolidated financial statements.

Management is responsible for the integrity of the financial information. Internal control systems are designed and maintained to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and to produce reliable accounting records for financial reporting purposes.

KPMG LLP were appointed by the Company's Board of Directors to express an audit opinion on the consolidated financial statements. Their examination included such tests and procedures, as they considered necessary, to provide a reasonable assurance that the consolidated financial statements are presented fairly in accordance with IFRS.

The Board of Directors is responsible for ensuring that management fulfills its responsibilities for financial reporting and internal control. The Board of Directors exercises this responsibility through the Audit Committee, with assistance from the Reserves Committee regarding the annual review of our petroleum and natural gas reserves. The Audit Committee meets regularly with management and the Independent Registered Public Accounting Firm to ensure that management's responsibilities are properly discharged, to review the consolidated financial statements and recommend that the consolidated financial statements be presented to the Board of Directors for approval. The Audit Committee also considers the independence of KPMG LLP and reviews their fees. The Independent Registered Public Accounting Firm has access to the Audit Committee without the presence of management.

CHANGES IN INTERNAL CONTROL OVER FINANCIAL REPORTING

The Company's internal controls over financial reporting commencing August 22, 2018 include Raging River's systems, processes and controls, as well as additional controls designed to result in complete and accurate consolidation of Raging River's results. Other than Raging River, there has been no change in the Baytex's internal control over financial reporting that occurred during 2018 that has materially affected, or are reasonably likely to materially affect, Baytex's internal control over financial reporting.

Edward D. LaFehr	Rodney D. Gray
President and Chief Executive Officer	*Executive Vice President and Chief Financial Officer*
Baytex Energy Corp.	Baytex Energy Corp.

March 5, 2019

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and Board of Directors of Baytex Energy Corp.:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of Baytex Energy Corp. (the "Company") as of December 31, 2018 and December 31, 2017, the consolidated statements of income (loss), comprehensive income (loss), changes in equity, and cash flows for the years then ended, and the related notes (collectively, the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and December 31, 2017, and the results of its operations and its cash flows for the years then ended, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the Company's internal control over financial reporting as of December 31, 2018, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 5, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures to respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

KPMG LLP

Chartered Professional Accountants

We have served as the Company's auditors since 2016.

March 5, 2019
Calgary, Canada

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Shareholders and the Board of Directors of Baytex Energy Corp.:

Opinion on Internal Control Over Financial Reporting

We have audited Baytex Energy Corp.'s (the "Company") internal control over financial reporting as of December 31, 2018, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on the criteria established in *Internal Control - Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) ("PCAOB"), the consolidated financial statements of the Company as of December 31, 2018 and 2017, and the related consolidated statements of income (loss), comprehensive income (loss), changes in equity, and cash flows for the years then ended, and related notes (collectively, the consolidated financial statements), and our report dated March 5, 2019 expressed and unqualified opinion on those consolidated financial statements.

The Company acquired Raging River Exploration Inc. during 2018, and management excluded from its assessment of the effectiveness of the Company's internal control over financial reporting as of December 31, 2018, Raging River Exploration Inc.'s internal control over financial reporting associated with total assets of $2.1 billion and total revenues, net of royalties, of $142.3 million included in the consolidated financial statements of the Company as of and for the year ended December 31, 2018. Our audit of internal control over financial reporting of the Company also excluded an evaluation of the internal control over financial reporting of Raging River Exploration Inc.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definition and Limitations of Internal Control Over Financial Reporting

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

KPMG LLP

Chartered Professional Accountants
March 5, 2019
Calgary, Canada

Baytex Energy Corp.
Consolidated Statements of Financial Position
(thousands of Canadian dollars)

As at	December 31, 2018	December 31, 2017
ASSETS		
Current assets		
Trade and other receivables (note 19)	$ 111,564	$ 112,844
Financial derivatives (note 19)	79,582	18,510
	191,146	131,354
Non-current assets		
Exploration and evaluation assets (note 6)	358,935	272,974
Oil and gas properties (note 7)	5,817,889	3,958,309
Other plant and equipment (note 8)	9,228	9,474
	$ 6,377,198	$ 4,372,111
LIABILITIES		
Current liabilities		
Trade and other payables (note 19)	$ 258,114	$ 144,542
Financial derivatives (note 19)	—	50,095
Onerous contracts (note 20)	1,986	2,574
	260,100	197,211
Non-current liabilities		
Bank loan (note 9)	520,700	212,138
Long-term notes (note 10)	1,583,240	1,474,184
Asset retirement obligations (note 11)	646,898	368,995
Deferred income tax liability (note 16)	310,836	204,698
	3,321,774	2,457,226
SHAREHOLDERS' EQUITY		
Shareholders' capital (note 12)	5,701,516	4,443,576
Contributed surplus	19,137	15,999
Accumulated other comprehensive income	667,874	463,104
Deficit	(3,333,103)	(3,007,794)
	3,055,424	1,914,885
	$ 6,377,198	$ 4,372,111

Commitments and contingencies (note 21)

See accompanying notes to the consolidated financial statements.

Naveen Dargan
Director, Baytex Energy Corp.

Gregory K. Melchin
Director, Baytex Energy Corp.

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

Years Ended December 31		2018		2017
Revenue, net of royalties				
Petroleum and natural gas sales (note 13)	$	1,428,870	$	1,099,867
Royalties		(313,754)		(241,892)
		1,115,116		857,975
Expenses				
Operating		311,592		269,283
Transportation		36,869		33,985
Blending and other		68,832		59,345
General and administrative		45,825		47,389
Transaction costs (note 4)		13,074		—
Exploration and evaluation (note 6)		21,729		8,253
Depletion and depreciation (notes 7 and 8)		558,684		481,929
Impairment (note 7)		285,341		—
Share-based compensation (note 14)		19,534		15,509
Financing and interest (note 17)		119,086		113,638
Financial derivatives gain (note 19)		(43,550)		(5,177)
Foreign exchange loss (gain) (note 18)		108,294		(87,060)
Gain on dispositions		(1,946)		(12,081)
Other expense (income)		(1,172)		2,216
		1,542,192		927,229
Net loss before income taxes		(427,076)		(69,254)
Income tax recovery (note 16)				
Current income tax recovery		(35)		(1,085)
Deferred income tax recovery		(101,732)		(155,343)
		(101,767)		(156,428)
Net income (loss) attributable to shareholders	$	(325,309)	$	87,174
Other comprehensive income (loss)				
Foreign currency translation adjustment		204,770		(166,759)
Comprehensive income (loss)	$	(120,539)	$	(79,585)
Net income (loss) per common share (note 15)				
Basic	$	(0.93)	$	0.37
Diluted	$	(0.93)	$	0.37
Weighted average common shares (note 15)				
Basic		351,542		234,787
Diluted		351,542		237,249

See accompanying notes to the consolidated financial statements.

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

	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 (note 12)	20,915	(20,915)	—	—	**—**
Share-based compensation (note 14)	—	15,509	—	—	**15,509**
Comprehensive income (loss) for the year	—	—	(166,759)	87,174	**(79,585)**
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 12)	(551)	—	—	—	**(551)**
Vesting of share awards (note 12)	19,496	(19,496)	—	—	**—**
Share-based compensation (note 14)	—	19,534	—	—	**19,534**
Comprehensive income (loss) for the year	—	—	204,770	(325,309)	**(120,539)**
Balance at December 31, 2018	$ 5,701,516	$ 19,137	$ 667,874	$ (3,333,103)	**$ 3,055,424**

See accompanying notes to the consolidated financial statements.

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

Years Ended December 31		**2018**		2017
CASH PROVIDED BY (USED IN):				
Operating activities				
Net income (loss) for the year	**$**	**(325,309)**	$	87,174
Adjustments for:				
Share-based compensation (note 14)		**19,534**		15,509
Unrealized foreign exchange loss (gain) (note 18)		**106,143**		(86,649)
Exploration and evaluation (note 6)		**21,729**		8,253
Depletion and depreciation (notes 7 and 8)		**558,684**		481,929
Impairment (note 7)		**285,341**		—
Non-cash financing and accretion (note 17)		**14,768**		13,156
Unrealized financial derivatives (gain) loss (note 19)		**(116,715)**		2,439
Gain on dispositions		**(1,946)**		(12,081)
Deferred income tax recovery (note 16)		**(101,732)**		(155,343)
Payments on onerous contracts (note 20)		**(588)**		(6,746)
Asset retirement obligations settled (note 11)		**(14,035)**		(13,471)
Change in non-cash working capital (note 20)		**39,448**		(8,962)
		485,322		325,208
Financing activities				
Increase (decrease) in bank loan		**(21,295)**		33,347
Common share issuance costs (notes 4 and 12)		**(755)**		—
Redemption of long-term notes		**—**		(8,582)
		(22,050)		24,765
Investing activities				
Additions to exploration and evaluation assets (note 6)		**(10,567)**		(7,118)
Additions to oil and gas properties (note 7)		**(485,154)**		(319,148)
Additions to other plant and equipment (note 8)		**(1,804)**		(238)
Property acquisitions		**(701)**		(71,643)
Proceeds from dispositions (notes 6 and 7)		**2,519**		11,786
Change in non-cash working capital (note 20)		**32,435**		33,683
		(463,272)		(352,678)
Change in cash		**—**		(2,705)
Cash, beginning of year		**—**		2,705
Cash, end of year	**$**	**—**	$	—
Supplementary information				
Interest paid	**$**	**102,230**	$	98,101
Income taxes paid	**$**	**—**	$	49

See accompanying notes to the consolidated financial statements.

1. REPORTING ENTITY

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

2. BASIS OF PRESENTATION

The consolidated financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board (the "IASB"). The significant accounting policies set forth below were consistently applied to all periods presented.

The consolidated financial statements were approved by the Board of Directors of Baytex on March 5, 2019.

The consolidated financial statements have been prepared on a historical cost basis, with the exception of certain fair value measurements noted in the accounting policies set forth below. The consolidated financial statements are presented in Canadian dollars which is the presentation currency of the Company. References to "US$" are to United States ("U.S.") dollars. All financial information is rounded to the nearest thousand, except per share amounts or where otherwise indicated.

Measurement Uncertainty and Judgments

The preparation of the consolidated financial statements requires management to make judgments, estimates and assumptions that affect the application of accounting policies and reported amounts of assets, liabilities, revenues and expenses. These judgments, estimates and assumptions are based on all relevant information available to the Company at the time of financial statement preparation. Actual results can differ from those estimates as the effect of future events cannot be determined with certainty. The key areas of judgment or estimation uncertainty that have a significant risk of causing material adjustment to the reported amounts of assets, liabilities, revenues, and expenses are discussed below.

<u>Reserves</u>

The Company uses estimates of oil, natural gas and natural gas liquids ("NGLs") reserves in the calculation of depletion and in the determination of fair value estimates for non-financial assets. The estimation of reserves is a complex process requiring significant judgment. Estimates of the Company's reserves are reviewed annually by independent reserves evaluators and represent the estimated recoverable quantities of crude oil, natural gas and NGLs and the related net cash flows. This evaluation of reserves is prepared in accordance with the reserves definition contained in National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" and the Canadian Oil and Gas Evaluation Handbook.

Estimates of economically recoverable oil, natural gas and NGLs and their future net cash flows are based on a number of variable factors and assumptions. Changes to estimates and assumptions such as forward price forecasts, production rates, ultimate reserve recovery, timing and amount of capital expenditures, production costs, marketability of oil and natural gas, royalty rates and other geological, economic and technical factors could have a significant impact on reported reserves. Changes in the Company's reserves estimates can have a significant impact on the carrying values of the Company's oil and gas properties, the calculation of depletion, the timing of cash flows for asset retirement obligations, asset impairments and estimates of fair value determined in accounting for business combinations.

<u>Cash-generating Units ("CGUs")</u>

The Company's oil and gas properties are aggregated into CGUs which are the smallest identifiable group of assets that generates cash flows that are largely independent of the cash flows from other assets or groups of assets. The aggregation of assets in CGUs requires management judgment and is based on geographical proximity, shared infrastructure and similar exposure to market risk.

<u>Identification of Impairment and Impairment Reversal Indicators</u>

Judgment is required to assess when indicators of impairment or impairment reversal exist and when a calculation of the recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication of impairment or impairment reversal. When completing this assessment, management considers internal and external sources of information including changes in future commodity prices, changes in industry regulations or royalty rates, asset performance and changes in the Company's estimates of economically recoverable reserves.

Measurement of Recoverable Amount

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including estimates of reserve quantities, the discount rates used to present value future cash flows, future commodity prices, assumptions regarding the timing and amount of future expenditures and future abandonment and reclamation obligations. Any changes to these estimates and assumptions could impact the calculation of the recoverable amount and the carrying value of assets.

Exploration and Evaluation ("E&E") Assets

Costs associated with acquiring oil and natural gas licenses and exploratory drilling are accumulated as E&E assets pending determination of technical feasibility and commercial viability. The determination of technical feasibility and commercial viability of E&E assets for the purposes of reclassifying such assets to oil and gas properties is subject to management judgment. Management uses the establishment of commercial reserves as the basis for determining technical feasibility and commercial viability. Upon determination of commercial reserves, E&E assets are tested for impairment and reclassified to oil and natural gas properties.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the assets acquired meet the definition of a business in accordance with IFRS.

Determination of the acquirer in a business combination requires management judgment. In determining the acquirer in a business combination, factors such as voting rights of all equity instruments, the intended corporate governance structure, composition of senior management of the combined company, and various metrics used to evaluate the relative size of each company are considered.

The determination of fair value assigned to assets acquired and liabilities assumed requires management to make assumptions and estimates including forecast benchmark commodity prices, estimates of reserves acquired and discount rates used to present value future cash flows. Changes in any of the assumptions or estimates used in determining the fair value of assets acquired and liabilities assumed could impact the amounts assigned to assets, liabilities and goodwill.

Joint Arrangements

Judgment is required to determine when the Company has joint control over an arrangement. In establishing joint control, management considers whether the decisions regarding the capital and operating activities of the arrangement require unanimous consent.

Classification of a joint arrangement once joint control has been established also requires judgment. The type of joint arrangement is determined by assessing the rights and obligations arising from the arrangement given the structure, legal form, and terms agreed upon by the parties sharing control. Arrangements where the controlling parties have rights to the net assets of the arrangement are classified as joint ventures. Arrangements where the controlling parties have rights to the assets and revenues, and obligations for the liabilities and expenses, are classified as joint operations. Baytex does not have any joint arrangements that are structured through joint venture arrangements.

Financial Derivatives

Financial derivatives are measured at fair value on each reporting date. The Company uses estimates of future commodity prices and interest rates available at period end to determine the fair value of outstanding financial derivatives. Changes in market pricing between period end and settlement of the derivative contracts could have a significant impact on financial results related to the financial derivatives.

Asset Retirement Obligations

The Company's provision for asset retirement obligations is based on estimated costs to abandon and reclaim the wells and the facilities, the estimated time period during which these costs will be incurred in the future, and discount and inflation rates. The provision for asset retirement obligations represents management's best estimate of the present value of the future abandonment and reclamation costs required under current regulatory requirements. Actual abandonment and reclamation costs could be materially different from estimated amounts.

Income Taxes

Regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change. Interpretation and application of existing regulation and legislation requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes. Estimates of future income taxes are subject to measurement uncertainty.

3. SIGNIFICANT ACCOUNTING POLICIES

Changes in significant accounting policies

Revenue from contracts with customers

Baytex adopted IFRS 15 Revenue from Contracts with Customers with a date of initial application of January 1, 2018, using the retrospective method. Baytex recognizes revenue when control of the product transfers to the customer and collection is reasonably assured. 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. The standard also requires new disclosure, as to the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. Baytex analyzed its revenue streams and its contracts with customers on adoption.

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 to 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 13 to these consolidated financial statements, in addition to the new significant accounting policy noted below.

Financial instruments

Baytex adopted IFRS 9 Financial Instruments, on January 1, 2018. The new standard includes three classifications for financial assets; measurement at amortized cost, fair value through profit or loss and fair value through comprehensive income. Under IFRS 9, where the fair value option is applied to financial liabilities, any change in fair value resulting from an entity's own credit risk is recorded through other comprehensive income or loss rather than net income or loss. The new standard also introduces a credit loss model for evaluating impairment of financial assets.

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. The table summarizes the change in classification categories for Baytex's financial assets and liabilities.

Financial Instrument	IAS 39 Classification	IFRS 9 Classification
Cash and cash equivalents	Fair value through profit or loss	Amortized cost
Trade and other receivables	Amortized cost	Amortized cost
Financial derivatives	Fair value through profit or loss	Fair value through profit or loss
Trade and other payables	Amortized cost	Amortized cost
Bank loan	Amortized cost	Amortized cost
Long-term notes	Amortized cost	Amortized cost

Significant accounting policies

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.

Many of the Company's exploration, development and production activities are conducted through joint arrangements. The consolidated financial statements include the Company's proportionate share of the assets, liabilities, revenues and expenses generated by joint arrangements.

Business Combinations

Business combinations are accounted for using the acquisition method of accounting when the acquired assets meet the definition of a business under IFRS. The cost of an acquisition is measured as cash paid and the fair value of assets given, equity instruments issued and liabilities incurred or assumed at the date of exchange. The acquired identifiable assets and liabilities assumed are measured at their fair values at the date of acquisition. Any excess of the cost of acquisition over the fair value of the net identifiable assets acquired is recognized as goodwill. If the cost of acquisition is below the fair values of the identifiable net assets acquired, the difference is recognized as a bargain purchase gain in net income or loss. Associated transaction costs are expensed when incurred.

Revenue Recognition

Revenue from the sale of light oil and condensate, heavy oil, natural gas liquids, and natural gas is recognized based on the consideration specified on contracts with customers. Baytex recognizes revenue by unit of production and when control of the product transfers to the customer and collection is reasonably assured. 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.

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 when Baytex acts in the capacity of an agent rather than as a principal.

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 include adjustments 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 the 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.

Exploration and Evaluation Assets

Pre-license costs, including certain geological, geophysical and seismic expenditures, are incurred before the legal rights to explore a specific area have been obtained. These costs are charged to exploration expense in the period in which they are incurred.

Once the legal right to explore has been acquired, costs directly associated with an exploration program are capitalized as an intangible asset until results of the exploration program have been evaluated. Costs capitalized as E&E assets include costs of license acquisition, technical services and studies, seismic acquisition, exploration drilling and testing of initial production results.

E&E costs are subject to technical, commercial and management review to confirm the continued intent to develop or otherwise extract the underlying reserves. The technical feasibility and commercial viability of extracting petroleum and natural gas resources is dependent on the existence of economically recoverable reserves for the project. If the asset is determined not to be technically feasible or commercially viable the accumulated E&E costs associated with the exploration project are charged to E&E expense in the period the determination is made.

Upon determination of technical feasibility and commercial viability, as evidenced by the classification of proved or probable reserves and management's intention to develop the E&E asset, the accumulated costs associated with the exploration project are tested for impairment and transferred to oil and gas properties.

Oil and Gas Properties

Items of oil and gas properties are initially recorded at cost. The initial cost of oil and gas properties includes the costs to acquire developed or producing oil and gas properties, and to develop oil and gas properties, such as costs of completing geological and geophysical surveys, drilling development wells, and the costs to construct and install development infrastructure such as wellhead equipment and processing facilities.

Oil and gas properties includes costs related to planned major inspection, overhaul and turnaround activities to maintain items of oil and gas properties and benefit future years of operations. Replacements outside of a major inspection, overhaul or turnaround are recognized as oil and gas properties when it is probable the future economic benefits of the replacement will be realized by the Company. The carrying amount of any replaced or disposed item of oil and gas properties is derecognized. Repair and maintenance costs incurred for servicing an item of oil and gas properties is recorded as operating expense as incurred.

Depletion and Depreciation

The costs associated with an item of oil and gas properties are depleted on a unit-of-production basis over proved plus probable reserves once commercial production has commenced. Future development costs required to bring those reserves into production are included in the depletable base. For purposes of the depletion calculation, petroleum and natural gas reserves are converted to a common unit of measurement on the basis of their relative energy content where six thousand cubic feet of natural gas equates to one barrel of oil equivalent.

The depreciation methods and estimated useful lives for other plant and equipment are as follows:

Classification	Method	Rate or period
Motor Vehicles	Diminishing balance	15%
Office Equipment	Diminishing balance	20%
Computer Hardware	Diminishing balance	30%
Furniture and Fixtures	Diminishing balance	10%
Leasehold Improvements	Straight-line over life of the lease	Various
Other Assets	Diminishing balance	Various

The expected lives of other plant and equipment are reviewed on an annual basis and, if necessary, changes in expected useful lives are accounted for prospectively. Field inventory, which is included in other plant and equipment, is valued at the lower of cost, using the weighted average cost method, or net realizable value and is not depreciated.

Impairment

Non-derivative financial assets

The Company assesses non-derivative financial assets at each reporting date to determine whether there is any objective evidence indicating that it is impaired. Objective evidence exists if one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows.

An impairment loss is reversed when there is objective evidence that the value of the financial assets has been partially or fully restored. For financial assets measured at amortized cost the reversal is recognized in net income or loss.

Non-financial assets

The Company reviews its non-financial assets, other than E&E assets, for indicators of impairment and impairment reversal at the end of each reporting period. The recoverable amount of the asset is estimated if indicators of impairment or impairment reversal exist. E&E assets are assessed for impairment when they are reclassified to oil and gas properties and if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

When reviewing for indicators of impairment and impairment reversal, and testing for impairment when indicators have been identified, assets are grouped together at a CGU level. The recoverable amount of an asset or CGU is the higher of its FVLCD and its VIU. FVLCD is determined as the amount that would be obtained from the sale of an asset or CGU in an arm's length transaction between willing parties. In determining FVLCD, recent market transactions are considered if available. In the absence of such transactions, an appropriate valuation model is used. VIU is assessed using the present value of the estimated future cash flows of the asset or CGU. The estimated future cash flows are adjusted for risks specific to the asset or CGU and are discounted using a pre-tax discount rate that reflects current market assessments of the time value of money.

Where the carrying amount of a CGU exceeds its recoverable amount, the CGU is considered impaired and is written down to its recoverable amount. The impairment reduces the carrying amount of any goodwill allocated to the CGU first, with any remaining impairment being allocated to the individual assets in the CGU on a pro-rata basis.

Impairments may be reversed for all CGUs and individual assets, other than goodwill, when there is indication that a previously recognized impairment may no longer exist or may have decreased. If such indication exists, the recoverable amount is estimated. An impairment may be reversed only to the extent that the asset's revised carrying amount does not exceed the carrying amount that would have been determined, net of depreciation and depletion, had no impairment been recognized. Impairment recognized in relation to goodwill is not reversed for subsequent increases in its recoverable amount.

Impairments and impairment reversals are recorded in net income or loss in the period the impairment or impairment reversal occurs.

Asset Retirement Obligations

The Company recognizes asset retirement obligations when it has a legal or constructive obligation as a result of past events, it is probable that an outflow of economic resources will be required to settle the obligation and a reliable estimate can be made of the amount of the obligation. The Company's asset retirement obligations are based on its net ownership in wells and facilities. Management estimates the costs to abandon and reclaim the wells and the facilities using existing technology and the estimated time period during which these costs will be incurred in the future.

Asset retirement obligations are recognized for future asset retirement costs associated with the abandonment and reclamation of the Company's E&E assets and oil and gas properties. Asset retirement obligations are measured at the present value of management's best estimate of the future cash flows required to settle the present obligation, using the risk-free interest rate. The present value of the liability is capitalized as part of the cost of the related asset and depleted over its useful life. The asset retirement obligation is accreted until the date of expected settlement of the retirement obligation and is recognized within finance expense in the statements of income or loss. Changes in the future cash flow estimates resulting from revisions to the estimated timing or amount of undiscounted cash flows or the discount rates are recognized as changes in the asset retirement obligation provision and related asset at each reporting date.

Foreign Currency Translation

Foreign transactions

Transactions completed in currencies other than the functional currency are translated into the functional currency at the exchange rates prevailing at the time of the transactions. Foreign currency assets and liabilities are translated to functional currency at the period-end exchange rate. Revenue and expenses are translated to functional currency using the average exchange rate for the period. Realized and unrealized gains and losses resulting from the settlement or translation of foreign currency transactions are included in net income or loss.

Foreign operations

The functional currency of the Company's subsidiaries is the currency of the primary economic environment in which the entity operates. Certain subsidiaries of the Company operate and transact primarily in currencies other than the Canadian dollar. The designation of a subsidiary's functional currency is a management judgment based on the currency of the primary economic environment in which the subsidiary operates.

The financial statements of each entity are translated into Canadian dollars in preparation of the Company's consolidated financial statements. The assets and liabilities of a foreign operation are translated to Canadian dollars at the period-end exchange rate. Revenues and expenses of foreign operations are translated to Canadian dollars using the average exchange rate for the period. Foreign exchange differences are recognized in other comprehensive income or loss.

If the Company or any of its entities disposes of its entire interest in a foreign operation, or loses control, joint control, or significant influence over a foreign operation, the accumulated foreign currency translation gains or losses related to the foreign operation are recognized in net income or loss.

Financial Instruments

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”). 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 measurement categories for each class of financial asset and financial liability is set forth in the following table.

Financial Instrument	Classification
Cash and cash equivalents	Amortized cost
Trade and other receivables	Amortized cost
Financial derivatives	Fair value through profit or loss
Trade and other payables	Amortized cost
Bank loan	Amortized cost
Long-term notes	Amortized cost

An embedded derivative is a component of a contract that modifies the cash flows of the contract. These hybrid contracts consist of a host contract and an embedded derivative. The embedded derivative is separated from the host contract and accounted for as a derivative unless the economic characteristics and risks of the embedded derivative are closely related to the host contract. The embedded derivatives are measured at FVTPL.

Transaction costs that are directly attributable to the acquisition or issue of a financial asset or a financial liability classified as FVTPL are expensed at inception of the contract. For a financial asset or a financial liability carried at amortized cost, transaction costs directly attributable to acquiring or issuing the asset or liability are added to, or deducted from, the fair value on initial recognition and amortized through net income or loss over the term of the financial instrument. Debt issuance costs related to the restructuring of credit facilities are capitalized and amortized as financing costs over the term of the credit facilities.

The Company formally documents its risk management objectives and strategies to manage exposures to fluctuations in commodity prices, interest rates and foreign currency exchange rates. The risk management policy permits the use of certain derivative financial instruments, including swaps and collars, to manage these fluctuations. All transactions of this nature entered into by the Company are related to underlying financial instruments or future petroleum and natural gas production. These instruments are classified as FVTPL. The Company does not use financial derivatives for trading or speculative purposes. The Company has not designated its financial derivative contracts as effective accounting hedges, and therefore has not applied hedge accounting. As a result, the Company applies the fair value method of accounting for all derivative instruments by recording an asset or liability on the statements of financial position and recognizing changes in the fair value of the instrument in the statements of income or loss for the current period. The fair values of these instruments are based on quoted market prices or, in their absence, third-party market indications and forecasts. Attributable transaction costs are recognized in net income or loss when incurred.

The Company has accounted for its physical delivery sales contracts, which were entered into and continue to be held for the purpose of receipt or delivery of non-financial items in accordance with its expected purchase, sale or usage requirements as executory contracts. As such, these contracts are not considered to be derivative financial instruments and have not been recorded at fair value on the statements of financial position. Settlements on these physical delivery sales contracts are recognized in revenue in the period the product is delivered to the sales point.

Impairment of financial assets is determined by calculating the expected credit loss ("ECL"). The Company measures an ECL allowance for trade and other receivables. The Company determines the ECL which is the probability of default events related to the financial asset by using historical realized bad debts and forward looking information. The carrying amounts of financial assets are reduced by the amount of the ECL through an allowance account and losses are recognized within general and administrative expense in the statement of income or loss.

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.

Income Taxes

Current and deferred income taxes are recognized in net income or loss, except when they relate to items that are recognized directly in equity, in which case the current and deferred taxes are also recognized directly in equity.

Current income taxes for the current and prior periods are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted at the end of the reporting period.

The Company follows the balance sheet asset and liability method of accounting for income taxes. Under this method, deferred income taxes are recorded for the effect of any temporary differences between the carrying amounts of assets and liabilities in the consolidated financial statements and the corresponding tax basis used in the computation of taxable income. Deferred income tax liabilities are generally recognized for all taxable temporary differences. Deferred income tax assets are recognized for all temporary differences deductible to the extent future recovery is probable. The carrying amount of deferred income tax assets is reviewed at the end of each reporting period and reduced to the extent that it is no longer probable that sufficient taxable income will be available to allow all or part of the asset to be recovered. Deferred income taxes are calculated using enacted or substantively enacted tax rates. Deferred income tax balances are adjusted for any changes in the enacted or substantively enacted tax rates and the adjustment is recognized in the period that the rate change occurs.

Share-based Compensation Plans

The Company has a full-value award plan (the "Share Award Incentive Plan") pursuant to which restricted awards and performance awards (collectively, "share awards") may be granted to the directors, officers and employees of the Company and its subsidiaries. The maximum number of common shares issuable under the Share Award Incentive Plan (and any other long-term incentive plans of the Company) shall not at any time exceed 3.8% of the then-issued and outstanding common shares.

Each restricted award entitles the holder to be issued the number of common shares designated in the restricted award (plus dividend equivalents). Each performance award entitles the holder to be issued the number of common shares designated in the performance award (plus dividend equivalents) multiplied by a payout multiplier. Expenses related to the Share Award Incentive Plan are determined based on the fair value of the share awards on the grant date which is based on quoted market prices for the Company's common shares. Both restricted and performance awards are expensed over the vesting period using the graded vesting method. The payout multiplier is dependent on the performance of the Company relative to pre-defined corporate performance measures for a particular period. In the case of both restricted and performance awards, the number of common shares to be issued on the applicable issue date is adjusted to account for the payments of dividends from the grant date to the applicable issue date.

The Company assumed share awards and share options plans from the acquisition of Raging River (see note 4). The share options were valued at the closing date of the transaction utilizing a Black-Scholes pricing model to value the share options. The share awards were valued at fair value using the quoted market price of the Company's common shares on the closing date of the transaction. The share awards assumed consist of restricted share awards and performance share awards with a fixed multiplier of 1.0. Share-based compensation is expensed over the remaining vesting period and recognized as share-based compensation expense, with a corresponding increase to contributed surplus.

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. IFRS 16 is required to be adopted either retrospectively or using the modified retrospective approach. The Company will adopt IFRS 16 on January 1, 2019 using the modified retrospective method. The modified retrospective approach does not require restatement of prior period comparative financial information as the Company will record the cumulative effect of applying the standard as an increase to right of use assets with a corresponding increase to lease obligations. The Company is currently in the process of quantifying the impact of the contracts that fall within the scope of IFRS 16. The Company expects adjustments for its office lease and the related subleases, field office leases, certain vehicles and field equipment, however, the full extent of the impact has not yet been finalized.

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. 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 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 fair value of oil and gas properties acquired was determined using estimates of proved plus probable reserves evaluated at December 31, 2018 by an independent reserves evaluator and adjusted for operations between August 22, 2018 and the effective date of the reserve evaluation. 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%.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. All amounts are final.

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 14).

(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 9).

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 period from August 22, 2018 to December 31, 2018, the acquisition contributed revenues of $158.8 million and operating income of $98.6 million. Had the acquisition occurred on January 1, 2018, revenues would have increased by $379.5 million and operating income would have increased by $273.2 million for the year. Operating income is defined as revenue, net of royalties, less operating, transportation and blending expense.

Transaction costs of $13.1 million were expensed as incurred and share issuance costs of $0.6 million (net of taxes of $0.2 million) were recorded in shareholders' capital in the year.

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 U.S.; and
- Corporate includes corporate activities and items not allocated between operating segments.

	Canada		U.S.		Corporate		Consolidated	
Years Ended December 31	**2018**	2017	**2018**	2017	**2018**	2017	**2018**	2017
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 619,215**	$ 478,572	**$ 809,655**	$ 621,295	**$ —**	$ —	**$ 1,428,870**	$ 1,099,867
Royalties	**(72,700)**	(58,672)	**(241,054)**	(183,220)	**—**	—	**(313,754)**	(241,892)
	546,515	419,900	**568,601**	438,075	**—**	—	**1,115,116**	857,975
Expenses								
Operating	**221,717**	181,995	**89,875**	87,288	**—**	—	**311,592**	269,283
Transportation	**36,869**	33,985	**—**	—	**—**	—	**36,869**	33,985
Blending and other	**68,832**	59,345	**—**	—	**—**	—	**68,832**	59,345
General and administrative	**—**	—	**—**	—	**45,825**	47,389	**45,825**	47,389
Transaction costs	**—**	—	**—**	—	**13,074**	—	**13,074**	—
Exploration and evaluation	**10,580**	8,253	**11,149**	—	**—**	—	**21,729**	8,253
Depletion and depreciation	**294,925**	199,149	**261,709**	280,933	**2,050**	1,847	**558,684**	481,929
Impairment	**65,000**	—	**220,341**	—	**—**	—	**285,341**	—
Share-based compensation	**—**	—	**—**	—	**19,534**	15,509	**19,534**	15,509
Financing and interest	**—**	—	**—**	—	**119,086**	113,638	**119,086**	113,638
Financial derivatives gain	**—**	—	**—**	—	**(43,550)**	(5,177)	**(43,550)**	(5,177)
Foreign exchange loss (gain)	**—**	—	**—**	—	**108,294**	(87,060)	**108,294**	(87,060)
Gain on dispositions	**(1,946)**	(12,048)	**—**	(33)	**—**	—	**(1,946)**	(12,081)
Other expense (income)	**—**	—	**—**	—	**(1,172)**	2,216	**(1,172)**	2,216
	695,977	470,679	**583,074**	368,188	**263,141**	88,362	**1,542,192**	927,229
Net income (loss) before income taxes	**(149,462)**	(50,779)	**(14,473)**	69,887	**(263,141)**	(88,362)	**(427,076)**	(69,254)
Income tax recovery								
Current income tax recovery	**—**	—	**(35)**	(1,085)	**—**	—	**(35)**	(1,085)
Deferred income tax recovery	**(40,723)**	622	**(26,049)**	(118,163)	**(34,960)**	(37,802)	**(101,732)**	(155,343)
	(40,723)	622	**(26,084)**	(119,248)	**(34,960)**	(37,802)	**(101,767)**	(156,428)
Net income (loss)	**$ (108,739)**	$ (51,401)	**$ 11,611**	$ 189,135	**$ (228,181)**	$ (50,560)	**$ (325,309)**	$ 87,174
Total oil and natural gas capital expenditures(1)	**$ 300,299**	$ 173,131	**$ 193,604**	$ 212,992	**$ —**	$ —	**$ 493,903**	$ 386,123

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

As at	**December 31, 2018**	December 31, 2017
Canadian assets	**$ 3,739,029**	$ 1,677,821
U.S. assets	**2,628,941**	2,684,816
Corporate assets	**9,228**	9,474
Total consolidated assets	**$ 6,377,198**	$ 4,372,111

6. EXPLORATION AND EVALUATION ASSETS

	December 31, 2018	December 31, 2017
Balance, beginning of year	**$ 272,974**	$ 308,462
Capital expenditures	**10,567**	7,118
Corporate acquisition (note 4)	**97,858**	—
Property acquisitions	**514**	—
Divestitures	**(1,021)**	(1,276)
Exploration and evaluation expense	**(21,729)**	(8,253)
Transfers to oil and gas properties (Note 7)	**(13,866)**	(20,198)
Foreign currency translation	**13,638**	(12,879)
Balance, end of year	**$ 358,935**	$ 272,974

At December 31, 2018 the Company identified indicators of impairment for the exploration and evaluation assets within the Conventional CGU. The estimated recoverable amount exceeded the carrying value of the of the exploration and evaluation assets in the Conventional CGU and no impairment was recorded. There were no indicators of impairment for exploration and evaluation assets in the remaining CGUs at December 31, 2018.

At December 31, 2017, there were no indicators of impairment for the Company's exploration and evaluation assets.

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
Transfers from exploration and evaluation assets (note 6)	20,198	—	20,198
Transfers from other assets (note 8)	5,124	—	5,124
Change in asset retirement obligations (Note 11)	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	485,154	—	485,154
Corporate acquisition (note 4)	1,748,368	—	1,748,368
Property acquisitions	202	—	202
Transfers from exploration and evaluation assets (note 6)	13,866	—	13,866
Change in asset retirement obligations (note 11)	238,662	—	238,662
Divestitures	(15)	—	(15)
Impairment	—	(285,341)	(285,341)
Foreign currency translation	325,969	(110,651)	215,318
Depletion	—	(556,634)	(556,634)
Balance, December 31, 2018	**$ 10,744,533**	**$ (4,926,644)**	**$ 5,817,889**

For the year ended December 31, 2018, the Company identified indicators of impairment for its Conventional and Eagle Ford CGUs and recorded total impairment expense to oil and gas properties of $285.3 million (2017 - nil). There were no indicators of impairment identified for the remaining CGUs as at December 31, 2018.

At December 31, 2018, indicators of impairment existed for the Conventional CGU due to a sustained decline in Canadian natural gas prices and a reduction in planned capital exploration and development expenditures. The recoverable amount was not sufficient to support the carrying amount of the CGU which resulted in an impairment of $65.0 million recorded as at December 31, 2018. The recoverable amount of the Conventional CGU was based on its VIU which was estimated using a discounted cash flow model based on an independent reserve report approved by the Board of Directors and a range of pre-tax discount rates between 8% and 20%.

At December 31, 2018, indicators of impairment existed for the Eagle Ford CGU due to the expected development plan outlined by the operator which resulted in a decline in the net present value of our proved plus probable reserves. The recoverable amount was not sufficient to support the carrying amount of the CGU which resulted in an impairment of $220.3 million recorded as at December 31, 2018. The recoverable amount of the Eagle Ford CGU was based on its VIU which was estimated using a discounted cash flow model based on an independent reserve report approved by the Board of Directors and a range of pre-tax discount rates between 8% and 20%.

The recoverable amount of each CGU was calculated at December 31, 2018 using the following benchmark reference prices for the years 2019 to 2023 adjusted for commodity differentials specific to the Company.

	2019	2020	2021	2022	2023
WTI crude oil (US$/bbl)	63.00	67.00	70.00	71.40	72.83
LLS crude oil (US$/bbl)	68.40	70.37	71.34	72.76	74.22
Edmonton par (CA$/bbl)	75.27	77.89	82.25	84.79	87.39
NYMEX gas (US$/mmbtu)	3.00	3.25	3.50	3.57	3.64
AECO (CA$/GJ)	1.95	2.44	3.00	3.21	3.30
Exchange rate (CAD/USD)	1.30	1.25	1.25	1.25	1.25

This data is combined with assumptions relating to long-term prices, inflation rates and exchange rates together with estimates of transportation costs and pricing of competing fuels to forecast long-term energy prices, consistent with external sources of information. The prices and costs subsequent to 2023 have been adjusted for inflation at an annual rate of 2.0%.

The following table demonstrates the sensitivity of the estimated recoverable amount of reasonably possible changes in key assumptions inherent in the estimate.

	Increase in discount rate of 1 percent	Decrease in discount rate of 1 percent	Increase in oil price of $2.50/bbl	Decrease in oil price of $2.50/bbl	Increase in gas price of $0.25/mcf	Decrease in gas price of $0.25/mcf
Conventional CGU	$ 4,501	$ (4,673)	$ (6,000)	$ 6,000	$ (12,000)	$ 12,000
Eagle Ford CGU	137,820	(155,562)	(155,559)	155,559	(31,385)	31,385
Impairment increase (decrease)	$ 142,321	$ (160,235)	$ (161,559)	$ 161,559	$ (43,385)	$ 43,385

8. OTHER PLANT AND EQUIPMENT

	Cost	Accumulated depreciation	Net book value
Balance, December 31, 2016	**$ 67,698**	**$ (51,339)**	**$ 16,359**
Capital expenditures	329	—	329
Dispositions, net of acquisitions	(255)	—	(255)
Transfers to oil and gas properties (note 7)	(5,124)	—	(5,124)
Foreign currency translation	—	12	12
Depreciation	—	(1,847)	(1,847)
Balance, December 31, 2017	**62,648**	**(53,174)**	**9,474**
Capital expenditures	1,804	—	1,804
Depreciation	—	(2,050)	(2,050)
Balance, December 31, 2018	**$ 64,452**	**$ (55,224)**	**$ 9,228**

9. BANK LOAN

		December 31, 2018		December 31, 2017
Bank loan - U.S. dollar denominated[1]	$	122,388	$	167,159
Bank loan - Canadian dollar denominated		399,906		46,217
Bank loan - principal		522,294		213,376
Unamortized debt issuance costs		(1,594)		(1,238)
Bank loan	$	520,700	$	212,138

(1) U.S. dollar denominated bank loan balance was US$89.7 million as at December 31, 2018 (US$133.5 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 August 22, 2018, Baytex amended its credit facilities to include the Term Loan assumed in conjunction with the acquisition of Raging River (note 4) which matures on June 4, 2020.

The extendible secured Revolving Facilities are comprised of a US$35 million operating loan and 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 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 December 31, 2018 and 2017, Baytex had $14.6 million of outstanding letters of credit under the credit facilities.

At December 31, 2018, Baytex was in compliance with all of the covenants contained in the credit facilities including the financial covenants as summarized below.

Covenant Description	Position as at December 31, 2018	Covenant
Senior Secured Debt[1] to Bank EBITDA[2] (Maximum Ratio)	0.64:1.00	3.50:1.00
Interest Coverage[3] (Minimum Ratio)	8.00:1.00	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 December 31, 2018, the Company's Senior Secured Debt totaled $536.9 million which includes $522.3 million of principal amounts outstanding and $14.6 million of letters of credit.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, unrealized gains and losses on financial derivatives, income tax, non-recurring losses, 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 December 31, 2018 was $833.7 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expense, 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 December 31, 2018 were $104.3 million.

10. LONG-TERM NOTES

		December 31, 2018		December 31, 2017
6.75% notes (US$150,000 – principal) due February 17, 2021		204,683		187,770
5.125% notes (US$400,000 – principal) due June 1, 2021		545,820		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		545,820		500,720
Total long-term notes - principal		1,596,323		1,489,210
Unamortized debt issuance costs		(13,083)		(15,026)
Total long-term notes - net of unamortized debt issuance costs	$	1,583,240	$	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 credit facilities and long-term notes unless the Company maintains a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA (as defined in note 9) to financing and interest expenses on a trailing twelve month basis) of 2.50:1.00. As at December 31, 2018, the fixed charge coverage ratio was 8.00:1.00.

11. ASSET RETIREMENT OBLIGATIONS

	December 31, 2018	December 31, 2017
Balance, beginning of year	**$ 368,995**	$ 331,517
Liabilities incurred	**12,537**	5,825
Liabilities settled	**(14,035)**	(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 17)	**10,914**	8,682
Change in estimate(1)	**33,453**	(24,028)
Changes in discount rates and inflation rates(2)	**192,672**	61,011
Foreign currency translation	**2,850**	(2,865)
Balance, end of year	**$ 646,898**	$ 368,995

(1) Changes in the estimated costs, the timing of abandonment and reclamation and the status of wells are factors resulting in a change in estimate.

(2) 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 a market discount rate.

The undiscounted amount of estimated cash flows required to settle the asset retirement obligations is $673.1 million (December 31, 2017 - $420.3 million). Based on an inflation rate of 2.00% (December 31, 2017 - 2.00%), the undiscounted amount of estimated future cash flows required to settle the obligation is $1,238.6 million (December 31, 2017 - $756.7 million). These costs are expected to be incurred over the next 50 years.

The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2018 using an estimated annual inflation rate of 2.00% (December 31, 2017 - 2.00%) and discounted at a risk free rate of 2.15% (December 31, 2017 - 2.50%) is $646.9 million (December 31, 2017 - $369.0 million).

12. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at December 31, 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	3,343	19,496
Issued on corporate acquisition (note 4)	315,266	1,238,995
Issuance costs, net of tax (note 4)	—	(551)
Balance, December 31, 2018	**554,060**	**$ 5,701,516**

13. 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 19. 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 consist 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.

	Year Ended December 31					
	2018			2017		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Light oil and condensate	**$ 169,335**	**$ 637,055**	**$ 806,390**	$ 23,876	$ 471,997	$ 495,873
Heavy oil	**411,794**	**—**	**411,794**	414,902	—	414,902
NGL	**14,531**	**97,008**	**111,539**	10,664	76,234	86,898
Natural gas	**23,555**	**75,592**	**99,147**	29,130	73,064	102,194
Total petroleum and natural gas sales	**$ 619,215**	**$ 809,655**	**$ 1,428,870**	$ 478,572	$ 621,295	$ 1,099,867

Included in accounts receivable at December 31, 2018 is $77.4 million (December 31, 2017 - $91.6 million) of accrued petroleum and natural gas sales related to deliveries for periods ended prior to the reporting date.

14. SHARE-BASED COMPENSATION PLAN

The Company recorded compensation expense related to the share awards and share options of $19.5 million for the year ended December 31, 2018 ($15.5 million for the year ended December 31, 2017).

Share Awards

The weighted average fair value of share awards granted during the year ended December 31, 2018 was $4.04 per restricted and performance award (December 31, 2017 - $5.75).

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
Assumed on corporate acquisition[2]	302	257	559
Vested and converted to common shares	(1,682)	(1,661)	(3,343)
Forfeited	(198)	(167)	(365)
Balance, December 31, 2018	**3,243**	**3,273**	**6,516**

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

(2) Following closing of the business combination (note 4), holders of 0.3 million Raging River restricted awards and 0.3 million performance awards are entitled to receive 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) performance awards associated with the business combination have a fixed payout multiplier of 1.0.

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, with an exercise price based on the pre-existing exercise price adjusted based on the exchange ratio.

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 December 31, 2018, 4.9 million share options with a weighted average exercise price of $6.70 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	—	—
Assumed on corporate acquisition (note 4)	9,187	6.63
Forfeited/Expired	(4,322)	6.57
Balance, December 31, 2018	**4,865**	**$ 6.70**

	Options Outstanding			**Options Exercisable**	
Exercise price	Number outstanding at December 31, 2018 (000s)	Weighted average remaining life (years)	Weighted average exercise price	Number exercisable at December 31, 2018 (000s)	Weighted average exercise price
$5.00 - $7.00	3,425	1.28	$ 6.28	2,007	$ 6.28
$7.01 - $9.00	1,440	1.04	7.68	960	7.68
Total	**4,865**	**1.21**	**$ 6.70**	**2,967**	**$ 6.73**

The fair value of each option granted was estimated on closing of the business combination (note 4) using the Black-Scholes option-pricing model with the following assumptions.

Risk-free interest rate (%)	2.0%
Expected life (years)	0.8 - 2.8
Expected volatility (%) (1)	50%
Dividend per share	—
Expected forfeiture rate (%)	—
Weighted average fair value at grant date ($/option)	0.25

(1) Expected volatility has been based on historical share volatility of the Company.

15. NET INCOME (LOSS) PER SHARE

Baytex calculates basic income or loss per share based on the net income or loss attributable to shareholders using the weighted average number of shares outstanding during the period. Diluted income 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 proceeds from the potential exercise of share options and the amount of unrecognized share -based compensation expense on all share awards and share options, if any, attributed to future services are assumed to be used to purchase common shares at the average market price during the year.

	Year Ended December 31					
	2018			2017		
	Net loss	**Common shares (000's)**	**Net loss per share**	Net income	Common shares (000's)	Net income per share
Net income (loss) - basic	**$ (325,309)**	**351,542**	**$ (0.93)**	$ 87,174	234,787	$ 0.37
Dilutive effect of share awards	**—**	**—**	**—**	—	2,462	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net income (loss) - diluted	**$ (325,309)**	**351,542**	**$ (0.93)**	$ 87,174	237,249	$ 0.37

For the year ended December 31, 2018, 6.5 million share awards and 4.9 million share options were excluded from the calculation of diluted earnings per share as the Company recorded a net loss. For the year ended December 31, 2017, no share awards were excluded from the calculation of diluted earnings per share and there were no share options outstanding at the time.

16. INCOME TAXES

The provision for income taxes has been computed as follows:

	Year Ended December 31	
	2018	2017
Net loss before income taxes	**$ (427,076)**	$ (69,254)
Expected income taxes at the statutory rate of 27.00% (2017 – 26.93%)(1)	**(115,311)**	(18,650)
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	**5,185**	4,177
Non-taxable portion of foreign exchange (gain) loss	**14,467**	(11,615)
Effect of change in income tax rates(1)	**—**	(104)
Effect of rate adjustments for foreign jurisdictions	**(22,119)**	(42,214)
Effect of U.S. tax reform(2)	**—**	(91,830)
Effect of change in deferred tax benefit not recognized(3)	**14,467**	(11,615)
Adjustments and assessments(4)	**1,544**	15,423
Income tax recovery	**$ (101,767)**	$ (156,428)

(1) Expected income tax rate increased due to an increase in the corporate income tax rate in Saskatchewan (from 11.75% to 12%).

(2) On December 22, 2017, the United States of America (the "U.S.") enacted the Tax Cuts and Jobs Act which altered the federal income tax law that applies to Baytex's U.S. subsidiary. The changes include a reduction of the statutory income tax rate to 21% from 35%, resulting in a $91.8 million deferred tax recovery in 2017.

(3) A deferred income tax asset has not been recognized for allowable capital losses of $139 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).

(4) 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.

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 follow the previously disclosed letter from the CRA received by Baytex in November 2014 proposing to issue such reassessments.

Baytex remains confident that the tax filings of the affected entities are correct and in September 2016, filed a notice of objection for each notice of reassessment received. These notices of objection will be reviewed by the Appeals Division of CRA; a process that Baytex estimates could take up to two years. If the Appeals Division upholds the notices of reassessment Baytex has the right to appeal to the Tax Court of Canada; a process that Baytex estimates could take a further two years. Should Baytex be unsuccessful at the Tax Court of Canada, additional appeals are available; a process that Baytex estimates could take another two years and potentially longer. The reassessments do not require Baytex to pay any amounts in order to participate in the appeals process. In July 2018, an Appeals Officer was assigned to its file.

By way of background, Baytex acquired all of the interests in 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, Baytex would 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 that may be applied to the years 2012 through 2015.

A continuity of the net deferred income tax liability is detailed in the following tables:

As at	January 1, 2018	Recognized in Net Loss	Share Issuance Costs	Business Combination	Foreign Currency Translation Adjustment	**December 31, 2018**
Taxable temporary differences:						
Petroleum and natural gas properties	$ (696,427)	$ (11,639)	$ —	$ (207,337)	$ (39,103)	**$ (954,506)**
Financial derivatives	8,528	(31,512)	—	1,498		**(21,486)**
Deferred income	(17,827)	17,827	—	—		**—**
Other	(5,956)	(2,538)	209	—	5,240	**(3,045)**
Deductible temporary differences:						
Asset retirement obligations	97,977	62,984	—	10,789	609	**172,359**
Non-capital losses	330,749	48,725	—	—	20,225	**399,699**
Finance costs	78,258	17,885	—	—		**96,143**
Net deferred income tax liability[1]	$ (204,698)	$ 101,732	$ 209	$ (195,050)	$ (13,029)	**$ (310,836)**

(1) Non-capital loss carry-forwards at December 31, 2018 totaled $1,733.8 million and expire from 2029 to 2038.

As at	January 1, 2017	Recognized in Net Loss	Share Issuance Costs	Business Combination	Foreign Currency Translation Adjustment	**December 31, 2017**
Taxable temporary differences:						
Petroleum and natural gas properties	$ (967,579)	$ 221,697	$ —	$ —	$ 49,455	**$ (696,427)**
Financial derivatives	7,869	659	—	—	—	**8,528**
Deferred income	(419)	(17,408)	—	—	—	**(17,827)**
Other	(5,018)	6,076	—	—	(7,014)	**(5,956)**
Deductible temporary differences:						
Asset retirement obligations	93,016	5,925	—	—	(964)	**97,977**
Non-capital losses	404,952	(48,380)	—	—	(25,823)	**330,749**
Finance costs	91,484	(13,226)	—	—	—	**78,258**
Net deferred income tax liability[(1)]	$ (375,695)	$ 155,343	$ —	$ —	$ 15,654	**$ (204,698)**

(1) Non-capital loss carry-forwards at December 31, 2017 totaled $1,478.5 million and expire from 2023 to 2037.

The following is a summary of Baytex's tax pools.

	December 31, 2018	December 31, 2017
Canadian Tax Pools		
Canadian oil and natural gas property expenditures	**$ 529,044**	$ 308,366
Canadian development expenditures	**765,289**	176,188
Canadian exploration expenditures	**8,875**	1,343
Undepreciated capital costs	**502,320**	228,739
Non-capital losses	**593,251**	337,808
Financing costs and other	**33,866**	46,986
Total Canadian tax pools	**$ 2,432,645**	$ 1,099,430
U.S. Tax Pools		
Depletion	**$ 180,367**	$ 183,406
Intangible drilling costs	**133,345**	204,857
Tangibles	**69,138**	108,631
Non-capital losses	**1,140,579**	1,140,673
Other	**407,654**	303,357
Total U.S. tax pools	**$ 1,931,083**	$ 1,940,924

17. FINANCING AND INTEREST

	Year Ended December 31	
	2018	2017
Interest on bank loan	**$ 15,637**	$ 11,439
Interest on long-term notes	**88,681**	89,043
Non-cash financing	**3,854**	4,474
Accretion on asset retirement obligations (note 11)	**10,914**	8,682
Financing and interest	**$ 119,086**	$ 113,638

18. FOREIGN EXCHANGE

	Year Ended December 31	
	2018	2017
Unrealized foreign exchange loss (gain)	**$ 106,143**	$ (86,649)
Realized foreign exchange loss (gain)	**2,151**	(411)
Foreign exchange loss (gain)	**$ 108,294**	$ (87,060)

19. 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.

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:

	December 31, 2018		December 31, 2017		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial Derivatives	**$ 79,582**	**$ 79,582**	$ 18,510	$ 18,510	Level 2
Total	**$ 79,582**	**$ 79,582**	$ 18,510	$ 18,510	
Financial assets at amortized cost					
Trade and other receivables	**$ 111,564**	**$ 111,564**	$ 112,844	$ 112,844	—
Total	**$ 111,564**	**$ 111,564**	$ 112,844	$ 112,844	
Financial Liabilities					
FVTPL					
Financial Derivatives	**$ —**	**$ —**	$ (50,095)	$ (50,095)	Level 2
Total	**$ —**	**$ —**	$ (50,095)	$ (50,095)	
Financial liabilities at amortized cost					
Trade and other payables	**$ (258,114)**	**$ (258,114)**	$ (144,542)	$ (144,542)	—
Bank loan	**(520,700)**	**(522,294)**	(212,138)	(213,376)	—
Long-term notes	**(1,583,240)**	**(1,492,363)**	(1,474,184)	(1,430,902)	Level 1
Total	**$ (2,362,054)**	**$ (2,272,771)**	$ (1,830,864)	$ (1,788,820)	

There were no transfers of financial instruments between Level 1 and Level 2 in during the years ended December 31, 2018 or 2017.

Financial Risk

Baytex is exposed to a variety of financial risks, including market risk, liquidity risk and credit risk. The Company's process to mitigate these risks is described below.

Market Risk

Market risk is the risk that the fair value or future cash flows of financial assets or liabilities will fluctuate due to movements in market prices. Market risk is comprised of foreign currency risk, interest rate risk and commodity price risk.

Foreign Currency Risk

Baytex is exposed to fluctuations in foreign exchange rates as a result of the U.S. dollar portion of its bank loan and long-term notes, crude oil sales based on U.S. dollar benchmark prices and commodity financial derivative contracts that are settled in U.S. dollars. The Company's net income or loss, comprehensive income or loss and cash flow will therefore be impacted by fluctuations in foreign exchange rates.

To manage the impact of foreign exchange rate fluctuations, the Company may enter into agreements to fix the Canadian to U.S. dollar exchange rate. At December 31, 2018 and 2017, the Company did not have any currency derivative contracts outstanding.

A $0.01 increase or decrease in the CAD/USD foreign exchange rate on the revaluation of outstanding U.S. dollar denominated assets and liabilities, would impact net income or loss before income taxes by approximately $8.8 million.

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

	Assets		Liabilities	
	December 31, 2018	December 31, 2017	**December 31, 2018**	December 31, 2017
U.S. dollar denominated	**US$80,857**	US$479	**US$963,351**	US$1,008,001

Interest Rate Risk

The Company's interest rate risk arises from the floating rate Revolving Facilities and Term Loan (note 9). Based on the Company's principle bank loan outstanding net of the interest rate swap, as at December 31, 2018, a change of 100 basis points in interest rates would have an impact on net income or loss before income taxes of approximately $3.2 million.

Interest Rate Swaps

Baytex had the following interest rate swaps outstanding as of March 5, 2019:

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

(1) Canadian Dollar Offered Rate.

The Company partially mitigates its exposure to interest rate risk by entering into interest rate swap transactions. A change of 100 basis points in the interest rates would impact net income or loss before income taxes for the year ended December 31, 2018 by approximately$0.4 million.

Commodity Price Risk

Baytex utilizes financial derivative contracts or physical delivery contracts to manage the risk associated with changes in commodity prices. The use of derivatives is governed by a Risk Management Policy approved by the Board of Directors of Baytex which sets out limits on the use of derivatives. Baytex does not use financial derivatives for speculative purposes. Baytex's financial derivative contracts are subject to master netting agreements that create a legally enforceable right to offset by the counterparty the related financial assets and financial liabilities.

When assessing the potential impact of crude oil price changes on the crude oil financial derivative contracts outstanding as at December 31, 2018, a US$1.00/bbl change in the underlying benchmark crude oil prices would impact net income or loss before income taxes by approximately $2.9 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at December 31, 2018, a $0.25 change in the underlying benchmark natural gas prices would impact net income or loss before income taxes by approximately $1.5 million.

Financial Derivative Contracts

Baytex had the following financial derivative contracts outstanding as of March 5, 2019:

	Remaining Period	Volume	Price/Unit[1]	Index		Fair Value[2] *($ millions)*
Oil						
Fixed - Sell	Jan 2019 to Jun 2019	2,000 bbl/d	US$62.85/bbl	WTI	$	8.0
3-way option [3]	Jan 2019 to Dec 2019	2,000 bbl/d	US$70.00/US$60.00/US$50.00	WTI	$	7.0
3-way option [3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$72.60/US$65.00/US$55.00	WTI	$	4.0
3-way option [3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$72.50/US$66.00/US$56.00	WTI	$	4.1
3-way option [3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$73.00/US$66.00/US$56.00	WTI	$	4.1
3-way option [3]	Jan 2019 to Dec 2019	2,000 bbl/d	US$73.00/US$67.00/US$57.00	WTI	$	8.3
3-way option [3]	Jan 2019 to Dec 2019	2,000 bbl/d	US$74.00/US$68.00/US$58.00	WTI	$	8.4
3-way option [3]	Jan 2019 to Dec 2019	2,000 bbl/d	US$75.00/US$61.70/US$49.00	WTI	$	9.1
3-way option [3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.00/US$69.90/US$60.00	WTI	$	4.3
3-way option [3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$76.00/US$71.00/US$61.00	WTI	$	4.4
3-way option [3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$78.00/US$73.00/US$63.00	WTI	$	4.5
3-way option [3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.50/US$65.50/US$55.50	Brent	$	3.1
3-way option [3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$77.55/US$70.00/US$60.00	Brent	$	3.7
3-way option [3]	Jan 2019 to Dec 2019	1,000 bbl/d	US$83.00/US$73.00/US$63.00	Brent	$	4.0
Basis Swap [4]	Mar 2019 to Jun 2019	2,000 bbl/d	WTI less US$14.75/bbl	WCS	$	—
Basis Swap [4]	Apr 2019 to Jun 2019	2,000 bbl/d	WTI less US$13.65/bbl	WCS	$	—
Basis Swap [4]	Jul 2019 to Sep 2019	4,000 bbl/d	WTI less US$17.38/bbl	WCS	$	—
Basis Swap [4]	Oct 2019 to Dec 2019	4,000 bbl/d	WTI less US$20.88/bbl	WCS	$	—
Natural Gas						
Fixed - Sell	Jan 2019 to Mar 2019	5,000 GJ/d	CAD$2.25	AECO	$	0.4
Fixed - Sell	Jan 2019 to Dec 2019	5,000 mmbtu/d	US$3.15	NYMEX	$	0.8
Fixed - Sell	Jan 2019 to Mar 2019	10,000 mmbtu/d	US$3.82	NYMEX	$	0.8
Fixed - Sell	Apr 2019 to Jun 2019	10,000 mmbtu/d	US$2.79	NYMEX	$	0.1
Fixed - Sell	Jul 2019 to Sep 2019	10,000 mmbtu/d	US$2.79	NYMEX	$	0.1
Fixed - Sell	Oct 2019 to Dec 2019	10,000 mmbtu/d	US$2.88	NYMEX	$	0.1
Total					**$**	**79.3**
Current asset					$	79.3

(1) Based on the weighted average price per unit for the period.
(2) Fair values as at December 31, 2018. For the purposes of the table, contracts entered subsequent to December 31, 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$70.00/US$60.00/US$50.00 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$50.00/bbl; Baytex receives US$60.00/bbl when WTI is between US$50.00/bbl and US$60.00/bbl; Baytex receives the market price when WTI is between US$60.00/bbl and US$70.00/bbl; and Baytex receives US$70.00/bbl when WTI is above US$70.00/bbl.
(4) Contracts entered subsequent to December 31, 2018.

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

	Year Ended December 31			
		2018		2017
Realized financial derivatives loss (gain)	**$**	**73,165**	$	(7,616)
Unrealized financial derivatives loss (gain)		**(116,715)**		2,439
Financial derivatives gain	**$**	**(43,550)**	$	(5,177)

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 March 5, 2019, Baytex had committed to deliver the following volumes of raw bitumen to market on rail:

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

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements, opportunities to issue additional common shares as well as reducing capital expenditures. As at December 31, 2018, Baytex had available unused bank credit facilities in the amount of $547.7 million (as at December 31, 2017 - $494.6 million). In the event the Company is not able to comply with the financial covenants contained in agreements with its lenders, the Company's ability to access additional debt may be restricted.

The timing of cash outflows relating to financial liabilities as at December 31, 2018 is outlined in the table below:

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 258,114**	$ 258,114	$ —	$ —	$ —
Bank loan(1) (2)	**522,294**	—	522,294	—	—
Long-term notes(2)	**1,596,323**	—	750,503	300,000	545,820
Interest on long-term notes(3)	**334,028**	92,367	156,525	72,350	12,786
	$ 2,710,759	$ 350,481	$ 1,429,322	$ 372,350	$ 558,606

(1) The bank loan matures on June 4, 2020 unless maturity is extended at Baytex's request.
(2) Principal amount of instruments.
(3) Excludes interest on bank loan as interest payments on bank loans fluctuate based on amounts outstanding and interest rates.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. As at December 31, 2018, the Company is exposed to credit risk with respect to its trade and other receivables and financial derivatives.

Credit risk is considered very low for the Company's trade and other receivables and financial derivatives due to the external credit ratings of its counterparties and Baytex's process for selecting and monitoring credit-worthy counterparties. Most of the Company's trade and other receivables relate to petroleum and natural gas sales and are exposed to typical industry credit risks. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts with only creditworthy entities. Letters of credit or parental guarantees may be obtained prior to the commencement of business with certain counterparties. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers all financial assets that are not impaired or past due to be of good credit quality.

The majority of the Company's credit exposure on accounts receivable at December 31, 2018 relates to accrued revenues for November and December 2018. Accounts receivables from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production, with natural gas sales from the Eagle Ford typically collected on the 25th day of the second month following production. Joint interest receivables are typically collected within one to three months following production. Included in accounts receivable at December 31, 2018 is $77.4 million (December 31, 2017 - $91.6 million) of accrued petroleum and natural gas sales related to deliveries for periods ended prior to the reporting date.

Should the Company determine that the ultimate collection of a receivable is in doubt, the carrying amount of accounts receivable is reduced by the use of an allowance for doubtful accounts and a charge to net income or loss. If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. As at December 31, 2018, allowance for doubtful accounts was $1.9 million (as at December 31, 2017 - $1.6 million).

In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. As at December 31, 2018, accounts receivable that Baytex has deemed past due (more than 90 days) but not impaired was $2.6 million (as at December 31, 2017 - $0.7 million). Baytex has estimated the lifetime expected credit loss as at and for the years ended December 31, 2018 to be nominal.

The Company's trade and other receivables, net of the allowance for doubtful accounts, were aged as follows at December 31, 2018.

Trade and Other Receivables Aging	**December 31, 2018**	December 31, 2017
Current (less than 30 days)	**$ 104,099**	$ 107,796
31-60 days	**3,037**	2,939
61-90 days	**1,842**	1,427
Past due (more than 90 days)	**2,586**	682
	$ 111,564	$ 112,844

20. SUPPLEMENTAL INFORMATION

Change in Non-Cash Working Capital Items

	Year Ended December 31	
	2018	2017
Trade and other receivables	**$ 1,280**	$ (673)
Trade and other payables	**113,572**	31,569
Non-cash working capital acquired (note 4)	**(46,773)**	(4,357)
	$ 68,079	$ 26,539
Changes in non-cash working capital related to:		
Operating activities	**$ 39,448**	$ (8,962)
Investing activities	**32,435**	33,683
Foreign currency translation on non-cash working capital	**(3,804)**	1,818
	$ 68,079	$ 26,539

Onerous Contracts

Onerous contracts result from unfavorable leases in which the unavoidable costs of meeting the obligations under the contracts exceed the economic benefits expected to be received.

	Year Ended December 31	
	2018	2017
Balance, beginning of year	**$ 2,574**	$ 9,504
Liabilities settled	**(588)**	(6,746)
Foreign currency translation	**—**	(184)
Balance, end of year	**$ 1,986**	$ 2,574

As at December 31, 2018, the Company has a provision totaling $2.0 million for an onerous contract related to office space that has been subleased (as at December 31, 2017 - $2.6 million). The provision represents the difference between the minimum future payments that the Company is required to make and the estimated recoveries from the sublease agreements.

Income Statement Presentation

Baytex's consolidated statements of income or loss and comprehensive income or loss are prepared primarily according to the nature of expense, with the exception of employee compensation costs which are included in both operating expense and general and administrative expense line items.

The following table details the amount of total employee compensation costs included in the operating expense and general and administrative expense.

	Year Ended December 31	
	2018	2017
Operating	**$ 12,140**	$ 13,424
General and administrative	**34,963**	36,086
Total employee compensation costs	**$ 47,103**	$ 49,510

21. COMMITMENTS AND CONTINGENCIES

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's cash flow from operations in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2018, and the expected timing of funding of these obligations, are noted in the table below.

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Operating leases	**$ 22,745**	7,484	12,492	2,753	16
Processing agreements	**47,717**	10,926	15,526	9,039	12,226
Transportation agreements	**112,002**	14,398	42,054	19,821	35,729
Total	**$ 182,464**	$ 32,808	$ 70,072	$ 31,613	$ 47,971

Baytex also has ongoing obligations related to the abandonment and reclamation of well sites and facilities which have reached the end of their economic lives. The present value of the future estimated abandonment and reclamation costs are included in the asset retirement obligations presented in the statements of financial position. Programs to abandon and reclaim wellsites and facilities are undertaken regularly in accordance with applicable legislative requirements.

Operating lease and sublease payments recognized as an expense during the year ended December 31, 2018 were $6.3 million (December 31, 2017 - $6.5 million). Baytex has entered into operating leases on office buildings in the ordinary course of business. The Company's operating lease agreements do not contain any contingent rent clauses. The Company has the option to renew or extend the leases on its office building with the new lease terms to be based on current market prices. None of the operating lease agreements contain purchase options or escalation clauses or any restrictions regarding dividends, further leases or additional debt.

The litigation and claims that Baytex is engaged with, which arose in the normal course of operations, are not expected to materially affect the Company's financial position or reported results of operations.

22. RELATED PARTIES

Balances and transactions between the Company and its subsidiaries, which are related parties of the Company, have been eliminated on consolidation and are not disclosed separately in this note.

Transactions with key management personnel (including directors) are noted in the table below.

	Year Ended December 31	
	2018	2017
Short-term employee benefits	**$ 8,703**	$ 7,840
Share-based compensation	**10,985**	3,569
Termination payments	**3,025**	275
Total compensation for key management personnel	**$ 22,713**	$ 11,684

23. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain financial flexibility 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 December 31, 2018, our capital structure was comprised of shareholders' capital, long-term debt, working capital and the bank loan.

Baytex monitors its estimated adjusted funds flow and the level of undrawn credit facilities. The Company's adjusted funds flow depends on a number of factors, including commodity prices, production and sales volumes, royalties, operating expenses, taxes and foreign exchange rates. In order to manage our capital structure and liquidity, we may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

At December 31, 2018, Baytex was in compliance with all of the covenants contained in the credit facilities and had unused capacity of $547.7 million.

We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and the Company's ability to generate funds for capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. We eliminate changes in non-cash working capital, transaction costs, 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. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our cash flow on a continuing basis. Transaction costs associated with the business combination (note 4) are excluded from adjusted funds flow as we consider the costs non-recurring and not reflective of our ability to generate adjusted funds flow on an ongoing basis. Adjusted funds flow should not be construed as an alternative to performance measures determined in accordance with IFRS, such as cash flow from operating activities and net income or loss.

Adjusted funds flow does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measures for other entities. It is reconciled to the nearest measure determined in accordance with IFRS, cash flow from operating activities, as set forth below.

	Year Ended December 31			
		2018		2017
Cash flow from operating activities	**$**	**485,322**	$	325,208
Change in non-cash working capital		**(39,448)**		8,962
Asset retirement obligations settled		**14,035**		13,471
Transaction costs	**$**	**13,074**	$	—
Adjusted funds flow	**$**	**472,983**	$	347,641

We believe that net debt assists in providing a more complete understanding of our financial position and provides a key measure to assess our liquidity. We calculate net debt based on the principal amounts of our bank loan and long-term notes outstanding, net of working capital. The current portion of financial derivatives is excluded as the valuation of the underlying contracts is subject to a high degree of volatility prior to the ultimate settlement. Onerous contracts are excluded from net debt as the underlying contracts do not represent an available source of liquidity. We use the principal amounts of the bank loan and long-term notes outstanding in the calculation of net debt as these amounts represent our ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the bank loan and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of liquidity or repayment obligation.

Net debt does not have any standardized meaning prescribed by IFRS and may not be comparable with the calculation of similar measure for other entities. The computation of net debt is set forth below.

		December 31, 2018		December 31, 2017
Bank loan - principal	**$**	**522,294**	$	213,376
Long-term notes - principal		**1,596,323**		1,489,210
Trade and other payables		**258,114**		144,542
Trade and other receivables		**(111,564)**		(112,844)
Net debt	**$**	**2,265,167**	$	1,734,284

At December 31, 2018, Baytex had $547.7 million of undrawn availability under its credit facilities (December 31, 2017 - $494.6 million).

PETROLEUM AND NATURAL GAS RESERVES AS AT DECEMBER 31, 2018

Baytex's year-end 2018 proved and probable reserves were evaluated by Sproule Associates Limited ("Sproule"), Ryder Scott Company, L.P. ("Ryder Scott") and GLJ Petroleum Consultants ("GLJ"), all independent qualified reserves evaluators. Sproule evaluated our Canadian reserves, other than the reserves associated with our Duvernay assets. GLJ evaluated the reserves associated with our Duvernay assets. Our United States properties were evaluated by Ryder Scott. Each evaluator used Sproule's December 31, 2018 forecast price and cost assumptions. All of our oil and gas properties were evaluated or audited in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook"). Reserves associated with our thermal heavy oil projects at Peace River, Gemini (Cold Lake) and Kerrobert have been classified as bitumen.

On August 22, 2018, Baytex and Raging River completed a strategic combination. Our 2018 reserves report reflects this strategic combination with a meaningful increase in our light oil reserves in Canada.

The following table sets forth our gross and net reserves volumes at December 31, 2018 by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in the table may not add due to rounding.

CANADA	Forecast Prices and Costs					
	Light and Medium Oil		Tight Oil		Heavy Oil	
Reserves Category	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)
Proved						
Developed Producing	30,987	29,089	740	652	24,922	20,092
Developed Non-Producing	263	256	—	—	1,161	1,006
Undeveloped	40,296	37,584	1,360	1,191	23,530	20,668
Total Proved	71,545	66,929	2,099	1,843	49,613	41,766
Probable	20,941	19,352	3,254	2,730	42,687	35,726
Total Proved Plus Probable	92,487	86,281	5,353	4,572	92,301	77,492

CANADA	Forecast Prices and Costs					
	Bitumen		Natural Gas Liquids[3]		Conventional Natural Gas[4]	
Reserves Category	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mbbl)	Net[2] (mbbl)	Gross[1] (mmcf)	Net[2] (mmcf)
Proved						
Developed Producing	1,934	1,478	1,401	1,070	55,986	50,308
Developed Non-Producing	7,746	7,008	3	3	1,943	1,533
Undeveloped	3,126	2,712	1,628	1,340	52,628	47,699
Total Proved	12,805	11,198	3,032	2,412	110,557	99,540
Probable	55,545	43,284	3,848	3,013	98,032	87,375
Total Proved Plus Probable	68,350	54,482	6,880	5,425	208,589	186,915

CANADA	Forecast Prices and Costs			
	Shale Gas		Oil Equivalent[5]	
Reserves Category	Gross[1] (mmcf)	Net[2] (mmcfl)	Gross[1] (mboe)	Net[2] (mboe)
Proved				
Developed Producing	1,432	1,310	69,553	60,983
Developed Non-Producing	—	—	9,497	8,528
Undeveloped	1,890	1,724	79,026	71,732
Total Proved	3,321	3,034	158,075	141,243
Probable	5,506	4,968	143,532	119,495
Total Proved Plus Probable	8,828	8,002	301,607	260,738

UNITED STATES

Reserves Category	Tight Oil Gross[1] (mbbl)	Tight Oil Net[2] (mbbl)	Natural Gas Liquids[3] Gross[1] (mbbl)	Natural Gas Liquids[3] Net[2] (mbbl)	Shale Gas Gross[1] (mmcf)	Shale Gas Net[2] (mmcf)
Proved						
Developed Producing	18,348	13,445	31,512	23,309	66,901	49,572
Developed Non-Producing	38	28	214	158	566	417
Undeveloped	32,334	23,700	39,856	29,312	80,367	59,166
Total Proved	50,720	37,174	71,582	52,779	147,835	109,155
Probable	18,625	13,680	34,625	25,441	66,043	48,502
Total Proved Plus Probable	69,345	50,854	106,207	78,220	213,878	157,657

Forecast Prices and Costs

UNITED STATES

Reserves Category	Conventional Natural Gas[4] Gross[1] (mmcf)	Conventional Natural Gas[4] Net[2] (mmcf)	Oil Equivalent[5] Gross[1] (mboe)	Oil Equivalent[5] Net[2] (mbbl)
Proved				
Developed Producing	24,993	18,357	65,176	48,076
Developed Non-Producing	49	36	354	261
Undeveloped	32,506	23,803	91,002	66,841
Total Proved	57,548	42,197	156,532	115,178
Probable	24,652	18,147	68,366	50,229
Total Proved Plus Probable	82,200	60,344	224,898	165,407

Forecast Prices and Costs

TOTAL

Reserves Category	Light and Medium Oil Gross[1] (mbbl)	Light and Medium Oil Net[2] (mbbl)	Tight Oil Gross[1] (mbbl)	Tight Oil Net[2] (mbbl)	Heavy Oil Gross[1] (mbbl)	Heavy Oil Net[2] (mbbl)
Proved						
Developed Producing	30,987	29,089	19,088	14,097	24,922	20,092
Developed Non-Producing	263	256	38	28	1,161	1,006
Undeveloped	40,296	37,584	33,693	24,891	23,530	20,668
Total Proved	71,545	66,929	52,819	39,016	49,613	41,766
Probable	20,941	19,352	21,879	16,410	42,687	35,726
Total Proved Plus Probable	92,487	86,281	74,698	55,426	92,301	77,492

Forecast Prices and Costs

TOTAL

Reserves Category	Bitumen Gross[1] (mbbl)	Bitumen Net[2] (mbbl)	Natural Gas Liquids[3] Gross[1] (mbbl)	Natural Gas Liquids[3] Net[2] (mbbl)	Shale Gas Gross[1] (mmcf)	Shale Gas Net[2] (mmcf)
Proved						
Developed Producing	1,934	1,478	32,912	24,379	68,333	50,882
Developed Non-Producing	7,746	7,008	217	160	566	417
Undeveloped	3,126	2,712	41,484	30,652	82,257	60,890
Total Proved	12,805	11,198	74,614	55,191	151,156	112,188
Probable	55,545	43,284	38,473	28,454	71,550	53,471
Total Proved Plus Probable	68,350	54,482	113,087	83,645	222,706	165,659

Forecast Prices and Costs

TOTAL

Reserves Category	Conventional Natural Gas[4] Gross[1] (mmcf)	Conventional Natural Gas[4] Net[2] (mmcf)	Oil Equivalent[5] Gross[1] (mboe)	Oil Equivalent[5] Net[2] (mboe)
	Forecast Prices and Costs			
Proved				
Developed Producing	80,980	68,665	134,729	109,059
Developed Non-Producing	1,991	1,569	9,851	8,789
Undeveloped	85,133	71,502	170,028	138,572
Total Proved	168,104	141,736	314,607	256,421
Probable	122,685	105,523	211,898	169,724
Total Proved Plus Probable	290,789	247,259	526,505	426,145

Notes:

(1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) "Net" reserves means Baytex's gross reserves less all royalties payable to others.

(3) Natural Gas Liquids includes condensate.

(4) Conventional Natural Gas includes associated, non-associated and solution gas.

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

Reserves Reconciliation

The following table reconciles the year-over-year changes in our gross reserves volumes by product type and reserves category using Sproule's forecast prices and costs. Please note that the data in table may not add due to rounding.

Reconciliation of Gross Reserves [1][2]
By Principal Product Type
Forecast Prices and Costs

Gross Reserves Category	Heavy Oil Proved (mbbl)	Heavy Oil Probable (mbbl)	Heavy Oil Proved + Probable (mbbl)	Bitumen Proved (mbbl)	Bitumen Probable (mbbl)	Bitumen Proved + Probable (mbbl)
December 31, 2017	46,706	39,757	86,463	13,266	55,726	68,992
Extensions	1,282	690	1,972	—	—	—
Infill Drilling	1,346	905	2,251	—	—	—
Improved Recoveries	1,952	4,621	6,574	—	—	—
Technical Revisions [3]	4,315	(4,922)	(607)	(205)	(178)	(382)
Discoveries	2	2	4	—	—	—
Acquisitions [4]	3,080	1,522	4,602	—	—	—
Dispositions	(1)	(2)	(2)	—	—	—
Economic Factors	149	114	262	—	(3)	(3)
Production	(9,218)	—	(9,218)	(256)	—	(256)
December 31, 2018	49,613	42,687	92,301	12,805	55,545	68,350

Gross Reserves Category	Light and Medium Crude Oil Proved (mbbl)	Light and Medium Crude Oil Probable (mbbl)	Light and Medium Crude Oil Proved + Probable (mbbl)	Tight Oil Proved (mbbl)	Tight Oil Probable (mbbl)	Tight Oil Proved + Probable (mbbl)
December 31, 2017	1,608	1,225	2,833	50,296	11,390	61,686
Extensions [4]	—	—	—	1,515	2,645	4,160
Infill Drilling [4]	10,823	2,856	13,679	1,062	147	1,209
Improved Recoveries	—	—	—	—	—	—
Technical Revisions [3]	273	(381)	(109)	5,285	7,154	12,438
Discoveries	—	—	—	65	15	80
Acquisitions [4]	61,992	17,234	79,226	625	594	1,219
Dispositions	—	—	—	—	—	—
Economic Factors	15	8	23	(175)	(65)	(240)
Production	(3,165)	—	(3,165)	(5,854)	—	(5,854)
December 31, 2018	71,545	20,941	92,487	52,819	21,879	74,698

Gross Reserves Category	Natural Gas Liquids[5] Proved (mbbl)	Natural Gas Liquids[5] Probable (mbbl)	Natural Gas Liquids[5] Proved + Probable (mbbl)	Shale Gas Proved (mmcf)	Shale Gas Probable (mmcf)	Shale Gas Proved + Probable (mmcf)
December 31, 2017	84,564	38,962	123,526	172,855	75,686	248,541
Extensions [4]	644	1,173	1,817	2,582	4,681	7,262
Infill Drilling	534	109	643	407	121	528
Improved Recoveries	—	—	—	—	—	—
Technical Revisions [3]	(5,742)	(1,716)	(7,458)	(10,715)	(9,111)	(19,826)
Discoveries	12	3	15	73	17	90
Acquisitions [4]	349	256	605	790	809	1,599
Dispositions	—	—	—	—	—	—
Economic Factors	(528)	(314)	(841)	(1,133)	(652)	(1,785)
Production	(5,220)	—	(5,220)	(13,702)	—	(13,702)
December 31, 2018	74,614	38,473	113,087	151,156	71,550	222,706

Gross Reserves Category	Conventional Natural Gas[6] Proved (mmcf)	Conventional Natural Gas[6] Probable (mmcf)	Conventional Natural Gas[6] Proved + Probable (mmcf)	Oil Equivalent[7] Proved (mboe)	Oil Equivalent[7] Probable (mboe)	Oil Equivalent[7] Proved + Probable (mboe)
December 31, 2017	181,837	100,724	282,560	255,556	176,461	432,017
Extensions (4)	66	185	251	3,882	5,319	9,201
Infill Drilling (4)	6,055	1,643	7,699	14,842	4,311	19,153
Improved Recoveries	—	—	—	1,952	4,621	6,574
Technical Revisions (3)	(24,918)	9,915	(15,004)	(2,013)	91	(1,922)
Discoveries	—	—	—	92	22	114
Acquisitions (4)	28,494	11,812	40,306	70,926	21,709	92,635
Dispositions	—	—	—	(1)	(2)	(2)
Economic Factors	(3,197)	(1,593)	(4,790)	(1,261)	(635)	(1,896)
Production	(20,232)	—	(20,232)	(29,368)	—	(29,368)
December 31, 2018	168,104	122,685	290,789	314,607	211,898	526,505

Notes:

(1) "Gross" reserves means the total working and royalty interest share of remaining recoverable reserves owned by Baytex before deductions of royalties payable to others.

(2) Reserves information as at December 31, 2018 and 2017 is prepared in accordance with NI 51-101.

(3) Negative technical revisions for conventional natural gas are largely the result of adjustments to our gas conservation bookings in Peace River area and reduced type well profiles in our Canadian conventional natural gas properties. Positive technical revisions for tight oil are the result of enhanced type well profiles on our Eagle Ford acreage, as well as the reclassification of some natural gas liquids volumes to tight oil. Negative technical revisions for shale gas and natural gas liquids are the result of the removal of certain drilling locations on our Eagle Ford acreage as well as reclassification of shale gas volumes to solution gas.

(4) Acquisitions are principally attributable to reserves associated with the Raging River combination. For light and medium crude oil and tight oil, reserves associated with the Raging River assets are captured within acquisitions, extensions and infill drilling. Total proved reserves of 11.5 mmboe and total proved plus probable reserves of 14.6 mmboe of the infill drilling additions are associated with the Raging River Acquisition. Total proved reserves of 2.6 mmboe and total proved plus probable reserves of 7.2 mmboe of the extensions additions are associated with the Raging River Acquisition.

(5) Natural gas liquids include condensate.

(6) Conventional natural gas includes associated, non-associated and solution gas.

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

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves at year-end 2018 by annualized Q4/2018 production.

	Q4/2018 Actual Production	Reserves Life Index (years) Proved	Reserves Life Index (years) Proved Plus Probable
Oil and NGL (bbl/d)	81,653	8.8	14.8
Natural Gas (mcf/d)	103,424	8.5	13.6
Oil Equivalent (boe/d)	98,890	8.7	14.6

Capital Program Efficiency

Based on the evaluation of our petroleum and natural gas reserves prepared in accordance with NI 51-101 by our independent qualified reserves evaluators, the efficiency of our capital program is summarized in the following table.

	2018	2017	2016	Three-Year Total / Average 2016 - 2018
Capital Expenditures ($ millions)				
Exploration and development	$ 495.7	$ 326.3	$ 224.8	$ 1,046.8
Acquisitions (net of dispositions)	1,603.9	59.9	(63.6)	1,600.2
Total	$ 2,099.6	$ 386.1	$ 161.2	$ 2,646.9
Change in Future Development Costs – 1P ($ millions)				
Exploration and development	$ 117.4	$ (132.6)	$ (219.4)	$ (234.6)
Acquisitions (net of dispositions)	870.0	35.5	7.6	913.1
Total	$ 987.4	$ (97.1)	$ (211.8)	$ 678.4
Change in Future Development Costs – 2P ($ millions)				
Exploration and Development	$ 132.3	$ (76.4)	$ 108.8	$ 164.7
Acquisitions (net of dispositions)	932.2	160.6	1.9	1,094.6
Total	$ 1,064.5	$ 84.2	$ 110.7	$ 1,259.4
PDP Reserves Additions (mboe)				
Exploration and development	31,330	23,752	17,120	72,202
Acquisitions (net of dispositions)	32,398	3,711	(1,710)	34,399
Total	63,728	27,463	15,410	106,601
1P Reserves Additions (mboe)				
Exploration and development	17,494	21,695	5,041	44,243
Acquisitions (net of dispositions)	70,925	6,821	(1,564)	76,168
Total	88,419	28,516	3,477	120,411
2P Reserves Additions (mboe)				
Exploration and development	31,224	34,398	17,253	82,895
Acquisitions (net of dispositions)	92,633	17,204	(2,408)	107,409
Total	123,857	51,602	14,845	190,304
F&D costs ($/boe) (1)				
PDP	$ 15.82	$ 13.73	$ 13.14	$ 14.50
1P	$ 35.05	$ 8.93	$ 1.07	$ 18.36
2P	$ 20.11	$ 7.26	$ 19.33	$ 14.61
FD&A costs ($/boe) (2)				
PDP	$ 32.95	$ 14.06	$ 10.50	$ 24.83
1P	$ 34.91	$ 10.13	$ — (5)	$ 27.62
2P	$ 25.55	$ 9.11	$ 18.33	$ 20.53
Ratios (based on 2P reserves)				
Production replacement ratio (3)	422%	201%	58%	237%
Recycle ratio (4)	1.2x	2.7x	0.9x	1.6x

Notes:

(1) F&D costs are calculated as total exploration and development expenditures (excluding acquisition and divestitures and including the change in FDC) divided by reserves additions from exploration and development activity.

(2) FD&A costs are calculated as total capital expenditures (including acquisition and divestitures and the change in FDC) divided by total reserves additions.

(3) Production Replacement Ratio is calculated as total reserves additions divided by total annual production (including acquisitions and divestitures).

(4) Recycle Ratio is calculated as operating netback divided by 2P F&D costs. Operating netback is calculated as revenue less royalties, operating expenses and transportation expenses.

(5) 2016 FD&A costs (1P) were negative due to the reduction in estimated Future Development Costs.

Net Present Value of Reserves (Forecast Prices and Costs)

The following table summarizes our independent reserves evaluators estimates of the net present value before income taxes of the future net revenue attributable to our reserves using Sproule's forecast prices and costs (and excluding the impact of any hedging activities). Please note that the data in the table may not add due to rounding.

Summary of Net Present Value of Future Net Revenue
As at December 31, 2018
Forecast Prices and Costs
Before Income Taxes and Discounted at (%/year)

CANADA

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 1,792,884	$ 1,544,771	$ 1,355,997	$ 1,212,741	$ 1,101,425
Developed Non-Producing	244,486	172,472	125,171	93,194	70,965
Undeveloped	1,841,321	1,279,571	907,327	654,251	476,320
Total Proved	3,878,692	2,996,814	2,388,494	1,960,186	1,648,709
Probable	3,862,671	2,304,632	1,538,566	1,108,674	841,887
Total Proved Plus Probable	$ 7,741,363	$ 5,301,446	$ 3,927,060	$ 3,068,859	$ 2,490,597

UNITED STATES

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 1,627,506	$ 1,192,348	$ 961,733	$ 820,072	$ 723,542
Developed Non-Producing	8,652	6,491	5,164	4,286	3,667
Undeveloped	1,667,167	1,099,049	759,576	542,510	396,760
Total Proved	3,303,324	2,297,888	1,726,473	1,366,868	1,123,969
Probable	1,750,388	901,795	531,484	343,816	238,512
Total Proved Plus Probable	5,053,712	3,199,683	2,257,957	1,710,684	1,362,481

TOTAL

Reserves Category	0% ($000s)	5% ($000s)	10% ($000s)	15% ($000s)	20% ($000s)
Proved					
Developed Producing	$ 3,420,390	$ 2,737,119	$ 2,317,729	$ 2,032,813	$ 1,824,967
Developed Non-Producing	253,138	178,963	130,335	97,480	74,631
Undeveloped	3,508,488	2,378,620	1,666,903	1,196,760	873,080
Total Proved	7,182,016	5,294,702	4,114,967	3,327,054	2,772,678
Probable	5,613,059	3,206,427	2,070,050	1,452,489	1,080,399
Total Proved Plus Probable	12,795,075	8,501,129	6,185,017	4,779,543	3,853,078

Sproule Forecast Prices and Costs

The following table summarizes the forecast prices used in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2018.

Year	WTI Cushing US$/bbl	LLS Onshore US$/bbl	Canadian Light Sweet $/bbl	Western Canada Select C$/bbl	Henry Hub US$/MMbtu	AECO C Spot C$/MMbtu	Operating Cost Inflation Rate %/Yr	Capital Cost Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2018 act.	64.77	69.81	68.49	52.34	3.07	1.53	2.5	4.2	0.77
2019	63.00	68.40	75.27	59.47	3.00	1.95	0.0	0.0	0.77
2020	67.00	70.37	77.89	62.31	3.25	2.44	2.0	2.0	0.80
2021	70.00	71.34	82.25	67.45	3.50	3.00	2.0	2.0	0.80
2022	71.40	72.76	84.79	69.53	3.57	3.21	2.0	2.0	0.80
2023	72.83	74.22	87.39	71.66	3.64	3.30	2.0	2.0	0.80
2024	74.28	75.70	89.14	73.10	3.71	3.39	2.0	2.0	0.80
2025	75.77	77.22	90.92	74.56	3.79	3.49	2.0	2.0	0.80
2026	77.29	78.76	92.74	76.05	3.86	3.58	2.0	2.0	0.80
2027	78.83	80.34	94.60	77.57	3.94	3.68	2.0	2.0	0.80
2028	80.41	81.94	96.49	79.12	4.02	3.78	2.0	2.0	0.80
2029	82.02	83.58	98.42	80.70	4.10	3.88	2.0	2.0	0.80
Thereafter					Escalation rate of 2.0%				

Future Development Costs

The following table sets forth future development costs deducted in the estimation of the future net revenue attributable to the reserves categories noted below.

Future Development Costs
As of December 31, 2018
Forecast Prices and Costs
($000s)

	CANADA		UNITED STATES		TOTAL	
	Proved Reserves	Proved plus Probable Reserves	Proved Reserves	Proved plus Probable Reserves	Proved Reserves	Proved plus Probable Reserves
2019	302,027	361,583	129,181	144,727	431,208	506,309
2020	457,359	633,766	292,260	292,260	749,619	926,025
2021	400,568	487,702	264,263	264,263	664,831	751,965
2022	276,701	451,347	273,975	273,975	550,676	725,323
2023	10,499	216,289	240,502	241,144	251,002	457,433
Remaining	1,414	308,388	16,398	559,839	17,812	868,227
Total (undiscounted)	1,448,569	2,459,074	1,216,580	1,776,209	2,665,148	4,235,283

Properties with No Attributed Reserves

The following table sets forth our undeveloped land holdings as at December 31, 2018.

	Undeveloped Acres	
	Gross	Net
Alberta	1,054,743	964,579
Saskatchewan	369,366	329,641
Total	1,424,109	1,294,220

Undeveloped land holdings are lands that have not been assigned reserves as at December 31, 2018. We estimate the value of our net undeveloped land holdings at December 31, 2018 to be approximately $164.6 million, as compared to $75.9 million as at December 31, 2017. This internal evaluation generally represents the estimated replacement cost of our undeveloped land, excluding the approximately 98,952 net acres of our undeveloped land that we expect to expire on or before December 31, 2019. In determining replacement cost, we analyzed land sale prices paid at Provincial Crown land sales for properties in the vicinity of our undeveloped land holdings.

Net Asset Value

Our estimated net asset value is based on the estimated net present value of all future net revenue from our reserves, before income taxes, as estimated by the Company's independent reserves engineers at year-end, plus the estimated value of our undeveloped land holdings, less asset retirement obligations, long-term debt and net working capital. This calculation can vary significantly depending on the oil and natural gas price assumptions. In addition, this calculation does not consider "going concern" value and assumes only the reserves identified in the reserves reports with no further acquisitions or incremental development.

The following table sets forth our net asset value as at December 31, 2018.

	Net Asset Value Forecast Prices and Costs Before Income Taxes and Discounted at (%/year)		
($ millions except per share amounts)	**5%**	**10%**	**15%**
Total net present value of proved plus probable reserves (before tax)	$ 8,501	$ 6,185	$ 4,780
Undeveloped land holdings (1)	165	165	165
Asset retirement obligations (2)	(147)	(57)	(36)
Net debt	(2,265)	(2,265)	(2,265)
Net Asset Value	$ 6,254	$ 4,028	$ 2,644
Net Asset Value per Share (3)	$ 11.29	$ 7.27	$ 4.77

Notes:

(1) The value of undeveloped land holdings generally represents the estimated replacement cost of our undeveloped land.
(2) Asset retirement obligations may not equal the amount shown on the statement of financial position as a portion of these costs are already reflected in the present value of proved plus probable reserves and the discount rates applied differ.
(3) Based on 554.1 million common shares outstanding as at December 31, 2018.

Advisory Regarding Oil and Gas Information

The reserves information contained in this report have been prepared in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" of the Canadian Securities Administrators ("NI 51-101"). Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2018, which will be filed on or before March 31, 2019. Listed below are cautionary statements that are specifically required by NI 51-101:

- Where applicable, oil equivalent amounts have been calculated using a conversion rate of six thousand cubic feet of natural gas to one barrel of oil. BOEs may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one barrel of oil is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
- With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.
- This report contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.

This report contains metrics commonly used in the oil and natural gas industry, such as “recycle ratio,” “operating netback,” and “reserves life index.” These terms do not have a standardized meaning and may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Such metrics have been included in this report to provide readers with additional measures to evaluate Baytex’s performance, however, such measures are not reliable indicators of Baytex’s future performance and future performance may not compare to Baytex’s performance in previous periods and therefore such metrics should not be unduly relied upon.

This report discloses drilling locations for our East Duvernay Shale assets. Drilling locations refer to Baytex’s total proved, probable and unbooked locations. Proved locations and probable locations account for drilling locations in our inventory that have associated proved and/or probable reserves and are derived from our most recent independent reserves evaluation dated as at December 31, 2018. Potential drilling opportunities are unbooked locations that are internal estimates based on our prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves. Unbooked locations are farther away from existing wells and, therefore, there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty whether such wells will result in additional oil and gas reserves, resources or production. In the East Duvernay Shale, Baytex's net drilling locations for the East Duvernay Shale assets include 6 proved, 9 probable and 160 unbooked locations.

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.

Notice to United States Readers

The petroleum and natural gas reserves contained in this report have generally been prepared in accordance with Canadian disclosure standards, which are not comparable in all respects to United States or other foreign disclosure standards. For example, the United States Securities and Exchange Commission (the "SEC") requires oil and gas issuers, in their filings with the SEC, to disclose only "proved reserves", but permits the optional disclosure of "probable reserves" (each as defined in SEC rules). Canadian securities laws require oil and gas issuers disclose their reserves in accordance with NI 51-101, which requires disclosure of not only "proved reserves" but also "probable reserves". Additionally, NI 51-101 defines "proved reserves" and "probable reserves" differently from the SEC rules. Accordingly, proved and probable reserves disclosed in this report may not be comparable to United States standards. Probable reserves are higher risk and are generally believed to be less likely to be accurately estimated or recovered than proved reserves.

In addition, under Canadian disclosure requirements and industry practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The SEC rules require reserves and production to be presented using net volumes, after deduction of applicable royalties and similar payments.

Moreover, Baytex has determined and disclosed estimated future net revenue from its reserves using forecast prices and costs, whereas the SEC rules require that reserves be estimated using a 12-month average price, calculated as the arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period. As a consequence of the foregoing, Baytex's reserve estimates and production volumes in this report may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

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
COSO	Committee of Sponsoring Organizations of the Treadway Commission
DRIP	Dividend Reinvestment Plan
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
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

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Director

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Director

Gregory K. Melchin [1,4]
Director

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Director

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

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Rodney D. Gray
Executive Vice President and Chief Financial Officer

Richard P. Ramsay
Executive Vice President and Chief Operating Officer

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Executive Vice President, Shale Oil

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Chad L. Kalmakoff
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Scott Lovett
Vice President, Corporate Development

Chad E. Lundberg
Vice President, Viking Business Unit

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Vice President, Land

AUDITORS

KPMG LLP

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

RESERVES ENGINEERS

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

TRANSFER AGENT

Computershare Trust Company of Canada

EXCHANGE LISTINGS

Toronto Stock Exchange
New York Stock Exchange
Symbol: **BTE**

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