BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the years ended December 31, 2017 and 2016
Dated March 5, 2018

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, 2017 and 2016. This information is provided as of March 5, 2018. In this MD&A, references to "Baytex", the "Company", "we", "us" and "our" and similar terms refer to Baytex Energy Corp. and its subsidiaries on a consolidated basis, except where the context requires otherwise. The results for the three months and year ended December 31, 2017 ("Q4/2017" and "2017") have been compared with the results for the three months and year ended December 31, 2016 ("Q4/2016" and "2016"). 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, 2017 and 2016, together with the accompanying notes and the Annual Information Form for the year ended December 31, 2017. These documents and additional information about Baytex are accessible on the SEDAR website at www.sedar.com and through the U.S. Securities and Exchange Commission at www.sec.gov. All amounts are in Canadian dollars, unless otherwise stated, and all tabular amounts are in thousands of Canadian dollars, except for percentages 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. We refer you to the end of the MD&A for our advisory on forward-looking information and statements.

NON-GAAP FINANCIAL 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, 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 capital investments, debt repayment, settlement of our abandonment obligations and potential future dividends. In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate changes in non-cash working capital and settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Adjusted funds flow should not be construed as an alternative to performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income or loss.

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

	Years Ended December 31	
($ thousands)	**2017**	2016
Cash flow from operating activities	**$ 325,208**	$ 247,365
Change in non-cash working capital	**8,962**	23,270
Asset retirement obligations settled	**13,471**	5,616
Adjusted funds flow	**$ 347,641**	$ 276,251

Net Debt

We believe that net debt assists in providing a more complete understanding of our financial position and provides a key measure to assess our liquidity.

The following table summarizes our calculation of net debt.

($ thousands)		**December 31, 2017**		December 31, 2016
Bank loan[1]	**$**	**213,376**	$	191,286
Long-term notes[1]		**1,489,210**		1,584,158
Working capital (surplus) deficiency[2]		**31,698**		(1,903)
Net debt	**$**	**1,734,284**	$	1,773,541

(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.

	Years Ended December 31			
($ thousands)		**2017**		2016
Petroleum and natural gas sales	**$**	**1,091,534**	$	780,095
Blending expense		**(51,012)**		(9,622)
Total sales, net of blending expense		**1,040,522**		770,473
Royalties		**241,892**		178,116
Operating expense		**269,283**		240,705
Transportation expense		**33,985**		28,257
Operating netback		**495,362**		323,395
Realized financial derivative gain		**7,616**		96,929
Operating netback after realized financial derivatives gain	**$**	**502,978**	$	420,324

Bank EBITDA

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

	Years Ended December 31			
($ thousands)		**2017**		2016
Net income (loss)	**$**	**87,174**	$	(485,184)
Plus:				
Financing and interest		**113,638**		114,199
Unrealized foreign exchange gain		**(86,649)**		(41,436)
Unrealized financial derivatives loss		**2,439**		140,136
Current income tax recovery		**(1,085)**		(8,042)
Deferred income tax recovery		**(155,343)**		(264,561)
Depletion and depreciation		**481,929**		508,309
Impairment		**—**		423,176
Gain on disposition of oil and gas properties		**(12,081)**		(43,907)
Non-cash items[1]		**23,762**		29,974
Bank EBITDA	**$**	**453,784**	$	372,664

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

2017 ANNUAL HIGHLIGHTS

Baytex delivered solid operating and financial results for 2017. Strong well performance in the U.S. and Canada resulted in average production of 70,242 boe/d which exceeded the high end of our annual guidance range of 69,500 - 70,000 boe/d. The disciplined execution of our 2017 capital program resulted in exploration and development expenditures of $326.3 million being fully funded by adjusted funds flow of $347.6 million.

Total production of 70,242 boe/d for 2017 was 8% higher than Q4/2016 exit production of 65,136 boe/d. Strong well performance in the Eagle Ford and new well production from our Canadian capital program, combined with reactivations on the acquired Peace River properties, contributed to the increase in production for 2017 relative to Q4/2016.

In Canada, exploration and development expenditures of $113.3 million were focused on our Peace River and Lloydminster properties. In total, we drilled 8.0 (8.0 net) wells at Peace River and 65.0 (32.7 net) wells at Lloydminster during 2017. Drilling results in both Peace River and Lloydminster have exceeded expectations after having limited activity on these lands in 2015 and 2016. Production for our Canadian operations averaged 33,564 boe/d for 2017, up from 32,936 boe/d reported for 2016. We closed the Peace River asset acquisition on January 20, 2017 and were able to reactivate certain wells which contributed to a 2% increase in production in Q4/2017 relative to Q4/2016.

In the U.S., exploration and development capital was $213.0 million for 2017 and we drilled 140 (32.8 net) wells and commenced production from 115 (28.7 net) wells during the year. Drilling and completion activity increased in Q4/2016 and continued at a consistent pace throughout 2017 with approximately 4 drilling rigs and 2 completion crews on our lands. With this increased activity and strong well performance from enhanced completion techniques utilizing higher proppant loading and increased frac stages, production for Q4/2017 increased 12% to 37,362 boe/d from 33,432 boe/d in Q4/2016. Production for 2017 was 36,678 boe/d, relatively consistent with 36,573 boe/d in 2016.

During 2017, strengthening global oil demand combined with the ongoing efforts of the Organization of Petroleum Exporting Countries ("OPEC") to balance the oil market with production curtailments began to stabilize oil pricing at levels above the multi-year lows experienced during 2016. The West Texas Intermediate ("WTI") benchmark oil price averaged US$50.95/bbl for 2017 which is an increase of 18% from US$43.33/bbl for 2016. Despite a recent widening of the price differential for Canadian heavy oil in late Q4/2017, the differential narrowed from US$13.84/bbl in 2016 to US$11.98/bbl in 2017 due to increased downstream demand combined with higher pipeline capacity available as a result of downtime from other heavy oil producers in Western Canada. The improvement in commodity prices during 2017, combined with tighter heavy oil differentials in Canada and improved contract pricing in the U.S. increased our realized sales price to $40.58/boe in 2017 from $30.29/boe in 2016.

We generated adjusted funds flow of $347.6 million for 2017, an increase of $71.4 million from adjusted funds flow of $276.3 million reported for 2016. The increase in adjusted funds flow in 2017 was primarily due to higher realized prices of $40.58/boe, which increased $10.29/boe as compared to $30.29/boe reported for 2016. The increase in realized prices for 2017 was partially offset by higher royalties, operating and transportation expenses and resulted in a $172.0 million or $6.60/boe increase in operating netback from 2016. The increase in operating netback was offset by an $89.3 million decrease in hedging gains as benchmark prices were higher relative to our contract prices in 2017 as compared to 2016.

At December 31, 2017, net debt was $1,734.3 million, a decrease of $39.2 million from $1,773.5 million at December 31, 2016. Adjusted funds flow for 2017 exceeded exploration and development expenditures and settlement of asset retirement obligations by $7.9 million which contributed to a reduction of net debt. The strengthening of the Canadian dollar reduced the reported amount of our U.S. dollar denominated debt at December 31, 2017 which more than offset the increase in net debt due to the Peace River acquisition that closed on January 20, 2017.

RESULTS OF OPERATIONS

The Canadian division includes our heavy oil assets in Peace River and Lloydminster and our conventional oil and natural gas assets in Western Canada. The U.S. division includes our Eagle Ford assets in Texas.

Production

	Years Ended December 31					
	2017			2016		
Daily Production	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Liquids (bbl/d)						
Heavy oil	**25,326**	**—**	**25,326**	23,586	—	23,586
Light oil and condensate	**1,163**	**20,151**	**21,314**	1,407	19,970	21,377
Natural Gas Liquids ("NGL")	**1,044**	**8,162**	**9,206**	1,274	8,075	9,349
Total liquids (bbl/d)	**27,533**	**28,313**	**55,846**	26,267	28,045	54,312
Natural gas (mcf/d)	**36,186**	**50,189**	**86,375**	40,015	51,167	91,182
Total production (boe/d)	**33,564**	**36,678**	**70,242**	32,936	36,573	69,509
Production Mix						
Heavy oil	**76%**	**—%**	**36%**	72%	—%	34%
Light oil and condensate	**3%**	**55%**	**30%**	4%	55%	31%
NGL	**3%**	**22%**	**13%**	4%	22%	13%
Natural gas	**18%**	**23%**	**21%**	20%	23%	22%

Our average production for 2017 was 70,242 boe/d which is consistent with 69,509 boe/d reported for 2016 and above the high end of our annual guidance range of 69,500 - 70,000 boe/d. Despite annual average production being consistent year over year, Q4/2017 production of 69,556 was up 7% from Q4/2016 due to strong well performance and higher activity levels in Canada and the U.S. relative to 2016 combined with the Peace River acquisition which closed on January 20, 2017.

In Canada, production of 33,564 boe/d for 2017 is consistent with average production of 32,936 boe/d reported for 2016. In Q4/2016, we increased the pace of development at Lloydminster and Peace River after having limited activity on these lands in 2015 and 2016. Positive results from our more active Canadian capital program combined with production from the Q1/2017 Peace River acquisition more than offset natural declines.

Production in the U.S. averaged 36,678 boe/d in 2017 which is consistent with 36,573 boe/d reported for 2016 despite the sale of approximately 1,000 boe/d of operated Eagle Ford production in Q3/2016. Strong performance from wells brought on production in late 2016 and throughout 2017 contributed to slightly higher average production relative to 2016. Enhanced completion techniques utilizing higher proppant loading and increased frac stages resulted in higher initial production rates from wells that commenced production in 2017 and resulted in Q4/2017 production of 37,362 boe/d as compared to 33,432 boe/d in Q4/2016.

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

North American crude oil prices were higher in 2017 relative to the multi-year lows experienced during 2016. The WTI benchmark oil price is the representative index for inland North American light oil pricing at Cushing, Oklahoma. WTI pricing ranged between US $45/bbl and US$58/bbl during 2017 as strengthening global demand and geopolitical concerns over supply from the Middle East resulted in improved U.S. benchmark prices late in the year. The WTI light oil benchmark averaged US$50.95/bbl for 2017, an increase of 18% from an average of US$43.33/bbl during 2016.

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. Increases in U.S. crude oil exports combined with an increase in global benchmark pricing has resulted in LLS trading at a premium to WTI for 2017. The LLS benchmark was US$53.26/bbl or a US $2.31/bbl premium to WTI for 2017 compared to US$43.82/bbl or a US$0.49/bbl premium to WTI in 2016.

The price received for our heavy oil sales in Canada is based on the Western Canadian Select ("WCS") benchmark price which trades at a discount to WTI due to the quality and lack of egress for Canadian grades of crude oil. The WCS heavy oil differential averaged US$11.98/bbl in 2017, narrower than US$13.84/bbl in 2016 as a result of an increase in demand and available pipeline capacity due to production downtime for other heavy oil producers. Pipeline outages in late 2017 have compounded existing transportation constraints and have resulted in increased crude inventories in Western Canada and a widening of the WCS heavy oil differential in Q4/2017.

Natural Gas

Natural gas prices were higher in 2017 relative to 2016 as increased exports to Mexico and increasing North American liquefied natural gas sales have resulted in lower storage levels. Canadian natural gas prices remain challenged as higher maintenance downtime on the Western Canadian pipeline system has created transportation bottlenecks and a lower AECO benchmark during the second half of 2017 as compared to 2016.

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. During 2017, the NYMEX natural gas benchmark averaged US$3.11/mmbtu, an increase of 26% from US$2.46/mmbtu for 2016.

In Canada, we received natural gas pricing based on the AECO benchmark which averaged $2.43/mcf during 2017. The AECO benchmark continues to trade at a significant discount to NYMEX as a result of increasing supply and limited market access for Canadian natural gas production.

The following tables compare selected benchmark prices and our average realized selling prices for the years ended December 31, 2017 and 2016.

	Years Ended December 31		
	2017	2016	Change
Benchmark Averages			
WTI oil (US$/bbl)[(1)]	**50.95**	43.33	18 %
WTI oil (CAD$/bbl)	**66.13**	57.44	15 %
WCS heavy oil (US$/bbl)[(2)]	**38.97**	29.49	32 %
WCS heavy oil (CAD$/bbl)	**50.59**	39.09	29 %
LLS oil (US$/bbl)[(3)]	**53.26**	43.82	22 %
LLS oil (CAD$/bbl)	**69.12**	58.08	19 %
CAD/USD average exchange rate	**1.2979**	1.3256	(2)%
Edmonton par oil ($/bbl)	**62.92**	53.01	19 %
AECO natural gas price ($/mcf)[(4)]	**2.43**	2.09	16 %
NYMEX natural gas price (US$/mmbtu)[(5)]	**3.11**	2.46	26 %

(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					
	2017			2016		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices(1)						
Heavy oil ($/bbl)(2)	**$ 38.46**	**$ —**	**$ 38.46**	$ 26.46	$ —	$ 26.46
Light oil and condensate ($/bbl)	**56.24**	**64.17**	**63.74**	46.21	50.60	50.32
NGL ($/bbl)	**27.98**	**25.59**	**25.86**	17.77	17.06	17.16
Natural gas ($/mcf)	**2.21**	**3.99**	**3.24**	2.01	3.21	2.69
Weighted average ($/boe)(2)	**$ 34.22**	**$ 46.41**	**$ 40.58**	$ 24.06	$ 35.89	$ 30.29

(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 costs.

Average Realized Sales Prices

Our weighted average sales price was $40.58/boe for 2017, up $10.29/boe from $30.29/boe reported for the year ended December 31, 2016. The increase in our weighted average sales price reflects improved benchmark pricing received for our sales volumes during 2017 relative to 2016.

In Canada, our realized heavy oil sales price averaged $38.46/bbl which is $12.00/bbl higher than realized pricing of $26.46/bbl for 2016. Our Canadian heavy oil production requires blending with diluent in order to meet pipeline transportation specifications. The price received for the blended product is recorded as heavy oil sales revenue. We include the cost of blending diluent in our realized heavy oil sales price in order to compare our realized pricing on our produced volumes to the WCS benchmark. The increase in our realized heavy oil sales price for 2017 is a result of the increase in WCS benchmark pricing (expressed in Canadian dollars) which increased by $11.50/bbl in 2017 relative to 2016.

Our realized Canadian light oil and condensate price averaged $56.24/bbl for 2017, an increase of $10.03/bbl from $46.21/bbl for 2016. The price received for Canadian light oil and condensate sales is discounted to benchmark oil prices with adjustments for quality and is net of fees and differentials that do not fluctuate with prices. The increase in realized light oil and condensate pricing relative to 2016 is consistent with a $9.91/bbl increase in Edmonton par pricing in 2017.

In the U.S., our realized light oil and condensate price was $64.17/bbl for the year ended December 31, 2017. This represents an increase of $13.57/bbl from $50.60/bbl reported for 2016, slightly higher than a $11.04/bbl increase in LLS benchmark pricing in 2017 as compared to 2016. Improved contract pricing following the re-negotiation of certain marketing arrangements along with increased pipeline capacity has tightened the pricing differential on our U.S. light oil and condensate realized price relative to the LLS benchmark for 2017. These factors more than offset the impact that a stronger Canadian dollar had on the LLS benchmark expressed in Canadian dollars and our realized pricing in 2017 relative to 2016.

For 2017, our realized NGL price was $25.86/bbl or 39% of WTI (expressed in Canadian dollars) compared to $17.16/bbl or 30% of WTI in 2016. Our realized price as a percentage of WTI can vary from period to period based on the product mix of our NGL volumes and changes in the market prices of the underlying products. The increase in our realized price is consistent with an increase in the market prices for propane and butane which have increased relative to WTI in 2017 as compared to 2016.

Our realized natural gas price in Canada was $2.21/mcf for 2017 compared to realized pricing of $2.01/mcf in 2016. The increase is a result of higher AECO benchmark pricing in 2017 relative to the comparative year. A portion of our Canadian natural gas sales are referenced to the AECO daily index which was lower throughout 2017 relative to the AECO monthly average index. Accordingly, our realized sales price for 2017 increased by $0.20/mcf from 2016 relative to a $0.34/mcf increase in the AECO monthly average over the same periods.

Our U.S. realized natural gas price was $3.99/mcf in 2017, up from $3.21/mcf reported for the year ended December 31, 2016. This represents an increase of $0.78/mcf which is consistent with the increase in the NYMEX natural gas benchmark (expressed in Canadian dollars) in 2017 relative to 2016.

Petroleum and Natural Gas Sales

	Years Ended December 31					
	2017			2016		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Heavy oil	**$ 406,569**	**$ —**	**$ 406,569**	$ 238,047	$ —	$ 238,047
Light oil and condensate	**23,876**	**471,997**	**495,873**	23,792	369,869	393,661
NGL	**10,664**	**76,234**	**86,898**	8,287	50,416	58,703
Total liquids sales	**441,109**	**548,231**	**989,340**	270,126	420,285	690,411
Natural gas sales	**29,130**	**73,064**	**102,194**	29,506	60,178	89,684
Total petroleum and natural gas sales	**470,239**	**621,295**	**1,091,534**	299,632	480,463	780,095
Heavy oil blending expense	**(51,012)**	**—**	**(51,012)**	(9,622)	—	(9,622)
Total sales, net of blending expense	**$ 419,227**	**$ 621,295**	**$ 1,040,522**	$ 290,010	$ 480,463	$ 770,473

Total petroleum and natural gas sales of $1.1 billion increased $311.4 million from $780.1 million reported for 2016. The increase was driven by higher realized pricing in 2017 as production was consistent with the prior year.

In Canada, petroleum and natural gas sales were $470.2 million for 2017, up 57% from $299.6 million in 2016. Sales increased as our weighted average realized price in Canada increased 42% from $24.06/boe in 2016 to $34.22/boe in 2017, primarily due to the increase in benchmark prices. Annual production of 33,564 boe/d for 2017 is slightly higher than 32,936 boe/d in 2016. The increase in oil and NGL production is a result of the Peace River acquisition and heavy oil drilling in 2017.

Petroleum and natural gas sales of $621.3 million in the U.S. increased 29% or $140.8 million from $480.5 million reported for the year ended December 31, 2016. The increase was driven primarily by a 29% increase in realized pricing of $46.41/boe for 2017 compared to $35.89/boe in 2016. Our active capital program and strong well performance more than offset the impact of the sale of our operated Eagle Ford properties in Q3/2016 and weather related downtime in Q3/2017, resulting in average production for 2017 which was relatively consistent with the prior year.

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 gross revenue. 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, 2017 and 2016.

	Years Ended December 31					
	2017			2016		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 58,672**	**$ 183,220**	**$ 241,892**	$ 37,720	$ 140,396	$ 178,116
Average royalty rate[(1)]	**14.0%**	**29.5%**	**23.2%**	13.0%	29.2%	23.1%
Royalty rate per boe	**$ 4.79**	**$ 13.69**	**$ 9.43**	$ 3.13	$ 10.49	$ 7.00

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

Total royalties for 2017 were $241.9 million and averaged 23.2% of petroleum and natural gas sales which is consistent with our annual guidance of approximately 23% of revenue. Our Canadian royalty rate averaged 14.0% of oil and natural gas sales for 2017, up from 13.0% in 2016 as a result of higher commodity prices. In the U.S., royalties for 2017 averaged 29.5% of petroleum and natural gas sales which is fairly consistent with 29.2% for 2016 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage. Total royalties of $241.9 million for 2017 increased $63.8 million from 2016 as a result of higher realized pricing in combination with a slight increase in our Canadian royalty rate.

Operating Expense

	Years Ended December 31					
	2017			2016		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Operating expense	**$ 181,995**	**$ 87,288**	**$ 269,283**	$ 142,242	$ 98,463	$ 240,705
Operating expense per boe	**$ 14.86**	**$ 6.52**	**$ 10.50**	$ 11.80	$ 7.36	$ 9.46

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

Total operating expense was $269.3 million ($10.50/boe) for 2017 as compared to $240.7 million ($9.46/boe) for 2016 and was in line with our annual guidance of approximately $10.50/boe for 2017. The increase in operating expense in 2017 was anticipated with higher operating expense in Canada due to the Peace River acquisition in Q1/2017 and with the reactivation of higher operating cost wells that were shut-in for a portion of 2016. Strong production results in Canada and the U.S. along with operating expense reductions on the acquired Peace River properties resulted in reduction to our per unit guidance in 2017 to approximately $10.50/boe from our original guidance range of $11.00 - $12.00/boe.

U.S. operating expense of $87.3 million ($6.52/boe) for 2017 was $11.2 million or $0.84/boe lower than $98.5 million ($7.36/boe) reported for 2016. A general reduction in costs on our non-operated properties combined with the disposition of our operated U.S. properties, which had higher per unit operating costs, resulted in the decrease in U.S. operating expense in 2017 compared to 2016. In 2017, the Canadian dollar strengthened against the U.S. dollar which further reduced our U.S. operating costs expressed in Canadian dollars relative to the prior year.

In Canada, operating expense was $182.0 million ($14.86/boe) for 2017, up $39.8 million or $3.06/boe from $142.2 million ($11.80/boe) from 2016. We anticipated an increase to Canadian operating costs following the Q1/2017 acquisition of Peace River properties which have higher per unit operating costs than our other properties combined with the reactivation of higher cost production that was shut-in for a portion of 2016. We have been able to mitigate some of these expected increases by reducing costs on the acquired Peace River properties and from continued cost saving initiatives.

Transportation Expense

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of heavy oil in Canada to pipeline and rail terminals. The following table compares our transportation expense for the years ended December 31, 2017 and 2016.

	Years Ended December 31					
	2017			2016		
($ thousands except for per boe)	**Canada**	**U.S.(1)**	**Total**	Canada	U.S.(1)	Total
Transportation expense	**$ 33,985**	**$ —**	**$ 33,985**	$ 28,257	$ —	$ 28,257
Transportation expense per boe	**$ 2.77**	**$ —**	**$ 1.33**	$ 2.34	$ —	$ 1.11

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

Transportation expense was $34.0 million ($2.77/boe) for 2017, up by $5.7 million or 20.3% as compared to $28.3 million ($2.34/boe) for 2016. An increase in trucking volumes and distances along with the Q1/2017 Peace River acquisition has resulted in higher transportation expense in 2017 relative to 2016. Transportation expense of $1.33/boe for 2017 was slightly below our annual guidance of approximately $1.40/boe.

Blending Expense

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

Blending expense for 2017 was $51.0 million compared to $9.6 million for 2016. The $41.4 million increase in blending expense during 2017 is due to additional blending diluent purchases associated with the acquired Peace River properties combined with higher diluent prices relative to 2016. The increase is also a result of higher pipeline blending activities at our Lloydminster properties during 2017 as a third party pipeline outage impacted these activities during 2016.

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 year ended December 31, 2017 and 2016.

	Years Ended December 31		
($ thousands)	**2017**	2016	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ 4,552**	$ 88,860	$ (84,308)
Natural gas	**3,064**	8,069	(5,005)
Total	**$ 7,616**	$ 96,929	$ (89,313)
Unrealized financial derivatives gain (loss)			
Crude oil	**$ (16,841)**	$ (122,249)	$ 105,408
Natural gas	**14,402**	(17,887)	32,289
Total	**$ (2,439)**	$ (140,136)	$ 137,697
Total financial derivatives gain (loss)			
Crude oil	**$ (12,289)**	$ (33,389)	$ 21,100
Natural gas	**17,466**	(9,818)	27,284
Total	**$ 5,177**	$ (43,207)	$ 48,384

The realized financial derivatives gain of $7.6 million for 2017 is a result of crude oil and natural gas market price indexes settling at levels below those set in our fixed price contracts. During 2017, we recorded realized gains of $3.1 million on our natural gas financial derivatives. These gains were primarily a result of the AECO price index for 2017 averaging lower than the fixed price of $2.85/GJ on 22,500 GJ/d of AECO contracts in place for 2017. Realized gains of $4.6 million related to our crude oil financial derivatives in place for 2017 were driven by $5.8 million of gains on 3,500 bbl/d of swap contracts with a fixed price of US$54.46/bbl and $2.5 million of gains on outstanding 3-way options where the market price of WTI settled below the purchased put price in certain months. These gains on WTI-based crude oil hedges were offset by $3.7 million of realized losses on WCS differential financial derivatives as the index settled below the prices set in our contracts throughout the year.

At December 31, 2017, the fair value of our financial derivative contracts represent a net liability of $31.6 million compared to a net liability of $29.1 million at December 31, 2016. The net liability of $31.6 million as at December 31, 2017 is primarily a result of futures pricing for crude oil indexes being higher than the prices set in our fixed price crude oil financial derivatives in place for 2018.

We had the following commodity financial derivative contracts as at March 5, 2018.

	Period	Volume	Price/Unit[(1)]	Index
Oil				
Basis swap	Jan 2018 to Jun 2018	2,000 bbl/d	WTI less US$14.23/bbl	WCS
Basis swap	Jan 2018 to Dec 2018	6,000 bbl/d	WTI less US$14.24/bbl	WCS
Fixed - Sell	Jan 2018 to Dec 2018	13,000 bbl/d	US$51.64/bbl	WTI
3-way option [(2)]	Jan 2018 to Dec 2018	2,000 bbl/d	US$60.00/US$54.40/US$40.00	WTI
Fixed - Sell	Jan 2018 to Dec 2018	4,000 bbl/d	US$61.31/bbl	Brent
Fixed - Sell	Feb 2018 to Dec 2018	1,000 bbl/d	US$61.04/bbl	WTI
Swaption [(3)]	Jan 2019 to Dec 2019	2,000 bbl/d	US$59.60/bbl	WTI
3-way option [(2)]	Jan 2019 to Dec 2019	2,000 bbl/d	US$70.00/US$60.00/US$50.00	WTI
3-way option [(2)]	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.50/US$65.50/US$55.50	Brent
Natural Gas				
Fixed - Sell	Jan 2018 to Dec 2018	10,000 mmbtu/d	US$3.03	NYMEX
Fixed - Sell	Jan 2018 to Dec 2018	5,000 GJ/d	$2.67	AECO
Fixed - Sell	Feb 2018 to Dec 2018	5,000 mmbtu/d	US$2.99	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$60/US$54.40/US$40 contract, Baytex receives WTI plus US$14.40/bbl when WTI is at or below US$40/bbl; Baytex receives US$54.40/bbl when WTI is between US$40/bbl and US$54.40/bbl; Baytex receives the market price when WTI is between US$54.40/bbl and US$60/bbl; and Baytex receives US$60/bbl when WTI is above US $60/bbl.
(3) For these contracts, the counterparty has the right, if exercised on December 31, 2018, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

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, 2017 and 2016.

	Years Ended December 31					
	2017			2016		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Sales volume (boe/d)	**33,564**	**36,678**	**70,242**	32,936	36,573	69,509
Operating netback:						
Total sales, net of blending expense	**$ 34.22**	**$ 46.41**	**$ 40.58**	$ 24.06	$ 35.89	$ 30.29
Less:						
Royalties	**4.79**	**13.69**	**9.43**	3.13	10.49	7.00
Operating expenses	**14.86**	**6.52**	**10.50**	11.80	7.36	9.46
Transportation expenses	**2.77**	**—**	**1.33**	2.34	—	1.11
Operating netback	**$ 11.80**	**$ 26.20**	**$ 19.32**	$ 6.79	$ 18.04	$ 12.72
Realized financial derivatives gain	**—**	**—**	**0.30**	—	—	3.81
Operating netback after financial derivatives gain	**$ 11.80**	**$ 26.20**	**$ 19.62**	$ 6.79	$ 18.04	$ 16.53

Operating netback after financial derivatives increased by $3.09/boe to $19.62/boe reported for 2017 from $16.53/boe for 2016. The increase in our realized sales price per boe during 2017 was offset partially by higher royalties, operating expenses and transportation expenses compared to 2016. The increase in operating and transportation expenses per boe in the current period was driven by higher operating cost properties which were shut-in for a portion of 2016 combined with the Q1/2017 Peace River acquisition, which has higher per unit operating and transportation expenses than our other properties. Realized gains on financial derivatives were lower in 2017 as index pricing for the year was higher relative to the price set in our fixed price contracts as compared to 2016.

Exploration and Evaluation Expense

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the derecognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of lease expiries, the accumulated costs of expiring leases, and the economic facts and circumstances related to the Company's exploration programs. Exploration and evaluation expense was $8.3 million for 2017 compared to $6.0 million for 2016.

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, 2017 and 2016.

	Years Ended December 31					
	2017			2016		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Depletion and depreciation[(1)]	**$ 200,996**	**$ 280,933**	**$ 481,929**	$ 215,078	$ 293,231	$ 508,309
Depletion and depreciation per boe	**$ 16.41**	**$ 20.98**	**$ 18.80**	$ 17.49	$ 22.03	$ 20.04

(1) Canada includes corporate depreciation.

Depletion and depreciation expense was $481.9 million ($18.80/boe) for 2017 compared to $508.3 million ($20.04/boe) reported for 2016. In Canada, depletion expense was lower in 2017 compared to 2016 primarily due to impairments recorded in Q4/2016 which reduced the carrying value and the depletion rate for certain Canadian properties. The U.S. depletion rate for 2017 is lower than the comparative period due to a lower average CAD/USD exchange rate in 2017 relative to 2016 combined with higher proved plus probable reserve volumes in 2017.

Impairment

In 2017, we did not identify any indicators of impairment or impairment reversal 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.

During 2016, we recorded total impairment expense of $423.3 million related to the de-recognition of E&E assets in the Eagle Ford and the write-down of oil and gas properties in Peace River and Lloydminster. An impairment charge of $166.6 million was recorded for the de-recognition of E&E assets in the Eagle Ford after changes in our development plan resulted in possible reserves being reclassified to contingent resources. We also recorded a $230.0 million impairment of oil and gas properties in our Peace River CGU associated with a decline in proved plus probable reserves due to the lower commodity price environment combined with reduced activity levels throughout 2016. In Q3/2016, we recorded a $26.6 million write-down on certain oil and gas properties in our Lloydminster CGU prior to their disposition in Q4/2016.

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, 2017 and 2016.

	Years Ended December 31		
($ thousands except for per boe)	**2017**	2016	Change
General and administrative expense	**$ 47,389**	$ 50,866	$ (3,477)
General and administrative expense per boe	**$ 1.85**	$ 2.00	$ (0.15)

We reported G&A expense of $47.4 million or $1.85/boe for the year ended December 31, 2017 compared to $50.9 million or $2.00/boe for 2016. Reduced staffing levels and our ongoing cost savings efforts have resulted in lower G&A expense in 2017 relative to the comparative period. Overhead recoveries were also higher during 2017 due to increased capital activity in Canada relative to 2016, which helped reduce G&A expense compared to 2016. When combined with average production that exceeded the high end of our annual guidance range, per unit G&A expense for the year ended December 31, 2017 was below our annual guidance of approximately $2.00/boe.

Share-Based Compensation Expense

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

We recorded SBC expense of $15.5 million for 2017 which is up from $13.9 million reported for 2016. SBC expense is higher in 2017 due to a higher grant date fair value assigned to share awards granted in 2017 as compared to units granted in 2016.

Financing and Interest Expense

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

Financing and interest expense was $113.6 million for 2017 which is consistent with $114.2 million reported for 2016. Cash interest expense of $100.5 million was down $3.2 million from 2016 due to lower interest on our long-term notes due to a strengthening Canadian dollar which reduced the amount of interest reported in Canadian dollars. This was offset by a $2.6 million increase in our non-cash interest primarily due to an increase in accretion expense related to our asset retirement obligations.

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. 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 the Canadian operations.

	Years Ended December 31		
($ thousands except for exchange rates)	**2017**	2016	Change
Unrealized foreign exchange gain	**$ (86,649)**	$ (41,436)	(45,213)
Realized foreign exchange gain	**(411)**	(1,242)	831
Foreign exchange gain	**$ (87,060)**	$ (42,678)	(44,382)
CAD/USD exchange rates:			
At beginning of period	**1.3427**	1.3840	
At end of period	**1.2518**	1.3427	

We recorded an unrealized foreign exchange gain of $86.6 million for 2017 due to a strengthening of the Canadian dollar relative to the U.S. dollar. The CAD/USD exchange rate was 1.2518 as at December 31, 2017 compared to 1.3427 as at December 31, 2016.

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 realized foreign exchange gains of $0.4 million for the year ended December 31, 2017 compared to gains of $1.2 million for 2016.

Income Taxes

	Years Ended December 31		
($ thousands)	**2017**	2016	Change
Current income tax recovery	**$ (1,085)**	$ (8,042)	$ 6,957
Deferred income tax recovery	**(155,343)**	(264,561)	109,218
Total income tax recovery	**$ (156,428)**	$ (272,603)	$ 116,175

The current income tax recovery was $1.1 million for 2017, as compared to $8.0 million for 2016. These current income tax recoveries relate to income tax losses that were incurred in 2017 and 2016, which have been used to recover a portion of income taxes paid in previous years.

The 2017 deferred income tax recovery of $155.3 million decreased $109.2 million from $264.6 million in 2016. The deferred income tax recovery for 2017 is lower compared to 2016 primarily due to lower deferred tax recoveries related to impairment of our Canadian and U.S. properties recorded in 2016. Deferred taxes for 2017 was also impacted by lower unrealized losses recorded on our financial derivatives contracts along with U.S. tax reform. On December 22, 2017, the United States of America enacted the Tax Cuts and Jobs Act which altered the federal income tax law that applies to our U.S. subsidiary. The most significant changes include a reduction of the statutory income tax rate to 21% from 35%, which resulted in a $91.8 million deferred tax recovery recorded for the year ended December 31, 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 follow the 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. These notices of objection will be reviewed by the Appeals Division of the CRA; a process that we estimate could take up to two years. 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.

Tax Pools

The Company has Canadian and U.S. tax pools, which are available to reduce future taxable income. Our cash income tax liability is dependent upon many factors, including the prices at which we sell our production, available income tax deductions and the legislative environment in place during the taxation year. Based upon the current forward commodity price outlook, projected production and cost levels, and currently enacted tax laws in Canada and the United States, we do not expect to pay material amounts of cash income taxes prior to 2022.

The income tax pools detailed below are deductible at various rates as prescribed by law.

($ thousands)	**December 31, 2017**	December 31, 2016
Canadian Tax Pools		
Canadian oil and natural gas property expenditures	**$ 308,366**	$ 198,525
Canadian development expenditures	**176,188**	250,239
Canadian exploration expenditures	**1,343**	210
Undepreciated capital costs	**228,739**	256,549
Non-capital losses	**337,808**	151,959
Financing costs and other	**46,986**	69,025
Total Canadian tax pools	**$ 1,099,430**	$ 926,507
U.S. Tax Pools		
Depletion	**$ 183,406**	$ 297,252
Intangible drilling costs	**204,857**	388,727
Tangibles	**108,631**	136,969
Non-capital losses	**1,140,673**	1,039,782
Other	**303,357**	201,896
Total U.S. tax pools	**$ 1,940,924**	$ 2,064,626

Net Income (Loss) and Adjusted Funds Flow

The components of adjusted funds flow and net income (loss) for the years ended December 31, 2017 and 2016 are set forth in the following table.

	Years Ended December 31		
($ thousands)	**2017**	2016	Change
Petroleum and natural gas sales	**$ 1,091,534**	$ 780,095	$ 311,439
Royalties	**(241,892)**	(178,116)	(63,776)
Revenue, net of royalties	**849,642**	601,979	247,663
Expenses			
Operating	**(269,283)**	(240,705)	(28,578)
Transportation	**(33,985)**	(28,257)	(5,728)
Blending	**(51,012)**	(9,622)	(41,390)
Operating netback	**$ 495,362**	$ 323,395	$ 171,967
General and administrative	**(47,389)**	(50,866)	3,477
Financing and interest	**(100,482)**	(103,685)	3,203
Realized financial derivatives gain	**7,616**	96,929	(89,313)
Realized foreign exchange gain	**411**	1,242	(831)
Other (expense) income	**(2,216)**	1,964	(4,180)
Current income tax recovery	**1,085**	8,042	(6,957)
Payments on onerous contracts	**(6,746)**	(770)	(5,976)
Adjusted funds flow	**$ 347,641**	$ 276,251	$ 71,390
Exploration and evaluation	**(8,253)**	(5,976)	(2,277)
Depletion and depreciation	**(481,929)**	(508,309)	26,380
Share based compensation	**(15,509)**	(13,882)	(1,627)
Non-cash financing and accretion	**(13,156)**	(10,514)	(2,642)
Unrealized financial derivatives loss	**(2,439)**	(140,136)	137,697
Unrealized foreign exchange gain	**86,649**	41,436	45,213
Gain on disposition of oil and gas properties	**12,081**	43,907	(31,826)
Impairment	**—**	(423,176)	423,176
Deferred income tax recovery	**155,343**	264,561	(109,218)
Non-cash other expense	**—**	(10,116)	10,116
Payments on onerous contracts	**6,746**	770	5,976
Net income (loss) for the period	**$ 87,174**	$ (485,184)	$ 572,358

We generated adjusted funds flow of $347.6 million for 2017, an increase of $71.4 million from adjusted funds flow of $276.3 million reported for 2016. The increase in adjusted funds flow in 2017 was primarily due to higher operating netback which increased $172.0 million from 2016 due to higher commodity prices which increased revenues, slightly offset by higher royalties, operating and transportation expenses. The increase in operating netback was offset by a decrease in hedging gains of $89.3 million along with a reduction of approximately $17.1 million in adjusted funds flow from a combination of increased payments on onerous contracts, other expenses and a smaller tax recovery.

In 2017, net income was $87.2 million compared to a net loss of $485.2 million in 2016. Net income increased $572.4 million in 2017 compared to 2016 mainly due to impairment of $423.2 million reported in 2016 compared to no impairment being recorded in 2017. Our unrealized financial derivative losses decreased $137.7 million and our unrealized gain on foreign exchange was $45.2 million higher in 2017 compared to 2016. This was offset by a reduction of $109.2 million in the deferred income tax recovery in 2017, which was larger in 2016 due to the impairment losses recorded.

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 $166.8 million foreign currency translation loss for 2017 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the strengthening of the Canadian dollar against the U.S. dollar. The CAD/USD exchange rate was 1.2518 as at December 31, 2017 compared to 1.3427 as at December 31, 2016.

Capital Expenditures

Capital expenditures for the years ended December 31, 2017 and 2016 are summarized as follows.

	Years Ended December 31					
	2017			2016		
($ thousands except for # of wells drilled)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Land and seismic	**$ 4,613**	**$ 1,153**	**$ 5,766**	$ 4,691	$ 6,098	$ 10,789
Drilling, completion and equipping	**81,564**	**199,849**	**281,413**	13,618	178,412	192,030
Facilities	**27,097**	**11,990**	**39,087**	7,564	14,400	21,964
Total exploration and development	**$ 113,274**	**$ 212,992**	**$ 326,266**	$ 25,873	$ 198,910	$ 224,783
Total acquisitions, net of proceeds from divestitures	**59,857**	**—**	**59,857**	(8,883)	(54,237)	(63,120)
Total oil and natural gas expenditures	**$ 173,131**	**$ 212,992**	**$ 386,123**	$ 16,990	$ 144,673	$ 161,663
Wells drilled (net)	**53.8**	**32.8**	**86.6**	4.0	36.9	40.9

We invested $326.3 million on exploration and development activities during 2017 which is $101.5 million higher than exploration and development expenditures of $224.8 million for 2016. Our capital program was focused on our high return assets in the Eagle Ford and accelerating activity on our heavy oil properties in Canada after an improvement in commodity prices from 2017.

In Canada, we initiated an operated drilling program in Q4/2016 and adjusted the pace of development as the outlook for commodity prices fluctuated throughout 2017. Total exploration and development expenditures in Canada were $113.3 million, up from $25.9 million in 2016 reflecting the deferral of all operated heavy oil drilling activity during the first nine months of 2016. We drilled 86 (53.8 net) wells and incurred drilling, completion and equipping costs of $81.6 million during 2017 compared to drilling 15 (4.0 net) wells during 2016 for $13.6 million. In Peace River, our cost savings initiatives have resulted in drill, completion and equipping costs of $2.5 million for operated wells drilled during 2017. Applying multi-lateral drilling and production techniques to our operated wells in Lloydminster has resulted in average drill, completion and equipping costs of $0.8 million per well in 2017. During 2017, we initiate the construction of a gas plant and invested in strategic infrastructure projects including pipeline expansions which will support growth in our expanded position in Peace River.

In the U.S., capital spending increased to $213.0 million in 2017 from $198.9 million in 2016 due to higher drilling and completion activity levels relative to 2016. In Q4/2016, we increased the pace of development on our Eagle Ford property and averaged 4 drilling crews and 2 completion crews on our lands throughout the year. We participated in the drilling of 140 (32.8 net) wells and initiated production from 115 (28.7 net) wells during 2017 compared to 36.9 net wells drilled and 36.3 net wells on production in 2016.

Acquisitions, net of divestitures, totaled $59.9 million for the year ended December 31, 2017 compared to net dispositions of $63.1 million in 2016. The acquisitions in 2017 includes the Q1/2017 Peace River acquisition for consideration of $66.1 million, net of minor dispositions throughout the year. Disposition activity in 2016 included the $54.2 million disposition of our operated assets in the Eagle Ford along with minor non-core dispositions in Canada.

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, 2017, our capital structure was comprised of shareholders' capital, long-term debt, working capital and our bank loan.

The capital intensive nature of our operations requires the Company 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. 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.

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, 2017, net debt was $1,734.3 million, a decrease of $39.2 million from $1,773.5 million at December 31, 2016. Adjusted funds flow for 2017 exceeded exploration and development expenditures and settlements of asset retirement obligations by $7.9 million which resulted in a reduction of net debt. The strengthening of the Canadian dollar reduced the reported amount of our U.S. dollar denominated debt at December 31, 2017 which more than offset the increase in net debt due to the $66.1 million Peace River acquisition which closed on January 20, 2017.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio. At December 31, 2017, our net debt to adjusted funds flow ratio was 5.0 compared to a ratio of 6.4 as at December 31, 2016. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2016 is attributed to higher adjusted funds flow from improved commodity prices and higher annual production in 2017, along with a decrease in net debt as at December 31, 2017.

Bank Loan

The revolving extendible secured credit facilities are comprised of a US$25 million operating loan, a US$350 million syndicated loan and a US$200 million syndicated loan for our wholly-owned subsidiary, Baytex Energy USA, Inc. (collectively, the "Revolving Facilities").

The Revolving Facilities are not borrowing base facilities and do not require annual or semi-annual reviews. The facilities contain standard commercial covenants including the financial covenants detailed below and do not require any mandatory principal payments prior to maturity on June 4, 2019. We may request an extension under the Revolving Facilities which could extend the revolving period for up to four years (subject to a maximum four-year term at any time). The agreement relating to the Revolving Facilities is accessible on the SEDAR website at www.sedar.com (filed under the category "Material contracts - Credit agreements" on April 13, 2016).

The weighted average interest rate on the credit facilities for 2017 was 4.1% as compared to 3.5% for 2016.

Covenants

On March 31, 2016, we amended our credit facilities and restructured the financial covenants applicable to the Revolving Facilities. The following table summarizes the financial covenants contained in the amended credit agreement and our compliance therewith as at December 31, 2017.

		Ratio for the Quarter(s) ending:			
Covenant Description	**Position as at December 31, 2017**	**December 31, 2017 to March 31, 2018**	**June 30, 2018 to September 30, 2018**	**December 31, 2018**	**Thereafter**
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	0.50:1.00	5.00:1.00	4.50:1.00	4.00:1.00	3.50:1.00
Interest Coverage (3) (Minimum Ratio)	4.54:1.00	1.25:1.00	1.50:1.00	1.75:1.00	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, 2017, the Company's Senior Secured Debt totaled $228 million.
(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, income tax, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis. Bank EBITDA for the twelve months ended December 31, 2017 was $454 million.
(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expenses excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended December 31, 2017 were $100 million.

If we exceed or breach any of the covenants under the Revolving Facilities or our long-term notes, we may be required to repay, refinance or renegotiate the loan terms and may be restricted from taking on further debt or paying dividends to our shareholders.

Long-Term Notes

We have four series of long-term notes outstanding that total $1.49 billion as at December 31, 2017. The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts our ability to raise additional debt beyond existing credit facilities and long-term notes unless we maintain a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA to financing and interest expenses on a trailing twelve month basis) of 2.5:1. As at December 31, 2017, the fixed charge coverage ratio was 4.54:1.00.

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

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

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

On July 13, 2017, we redeemed the remaining US$6.4 million principal amount of 7.5% senior unsecured notes assumed pursuant to the acquisition of Aurora Oil & Gas Limited on June 11, 2014.

Shareholders' Capital

We are authorized to issue an unlimited number of common shares and 10,000,000 preferred shares. The rights and terms of preferred shares are determined upon issuance. During the year ended December 31, 2017, we issued 2.0 million common shares pursuant to our share-based compensation program. As at March 5, 2018, we had 236.6 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, 2017 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	**$ 144,542**	$ 144,542	$ —	$ —	$ —
Bank loan(1) (2)	**213,376**	—	213,376	—	—
Long-term notes(2)	**1,489,210**	—	—	988,490	500,720
Interest on long-term notes(3)	**398,635**	86,377	172,754	99,609	39,895
Operating leases	**29,926**	7,727	13,510	8,689	—
Processing agreements	**41,845**	6,993	9,164	9,004	16,684
Transportation agreements	**31,948**	2,602	14,635	13,661	1,050
Total	**$ 2,349,482**	$ 248,241	$ 423,439	$ 1,119,453	$ 558,349

(1) The bank loan is covenant-based with a revolving period that is extendible annually for up to a four-year term. Unless extended, the revolving period will end on June 4, 2019, with all amounts to be repaid on such date.
(2) Principal amount of instruments.
(3) Excludes interest on bank loan as interest payments on bank loans fluctuate based on interest rate and bank loan balance.

We also have ongoing obligations related to the abandonment and reclamation of well sites and facilities when they reach the end of their economic lives. Programs to abandon and reclaim well sites and facilities are undertaken regularly in accordance with applicable legislative requirements.

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)		**2017**		2016		2015
Revenues, net of royalties	**$**	**849,642**	$	601,979	$	879,999
Adjusted funds flow	**$**	**347,641**	$	276,251	$	516,417
Per common share - basic	**$**	**1.48**	$	1.30	$	2.67
Per common share - diluted	**$**	**1.47**	$	1.30	$	2.67
Net income (loss)	**$**	**87,174**	$	(485,184)	$	(1,142,880)
Per common share - basic	**$**	**0.37**	$	(2.29)	$	(5.77)
Per common share - diluted	**$**	**0.37**	$	(2.29)	$	(5.77)
Total assets	**$**	**4,372,111**	$	4,594,085	$	5,488,498
Bank loan - principal	**$**	**213,376**	$	191,286	$	256,749
Long term notes - principal	**$**	**1,489,210**	$	1,584,158	$	1,623,658
Cash dividends or distributions declared per common share	**$**	**—**	$	—	$	0.80
Average wellhead prices, net of blending costs ($/boe)	**$**	**40.58**	$	30.29	$	35.40
Total production (boe/d)		**70,242**		69,509		84,648

QUARTERLY FINANCIAL INFORMATION

($ thousands, except per common share amounts)	2017 Q4	2017 Q3	2017 Q2	2017 Q1	2016 Q4	2016 Q3	2016 Q2	2016 Q1
Petroleum and natural gas sales	**302,186**	254,430	274,369	260,549	233,116	197,648	195,733	153,598
Net income (loss)	**76,038**	(9,228)	9,268	11,096	(359,424)	(39,430)	(86,937)	607
Per common share - basic	**0.32**	(0.04)	0.04	0.05	(1.66)	(0.19)	(0.41)	—
Per common share - diluted	**0.32**	(0.04)	0.04	0.05	(1.66)	(0.19)	(0.41)	—
Adjusted funds flow	**105,796**	77,340	83,136	81,369	77,239	72,106	81,261	45,645
Per common share - basic	**0.45**	0.33	0.35	0.35	0.36	0.34	0.39	0.22
Per common share - diluted	**0.44**	0.33	0.35	0.34	0.36	0.34	0.39	0.22
Exploration and development	**90,156**	61,544	78,007	96,559	68,029	39,579	35,490	81,685
Canada	**41,864**	14,487	18,439	38,484	12,151	6,120	2,747	4,855
U.S.	**48,292**	47,057	59,568	58,075	55,878	33,459	32,743	76,830
Acquisitions, net of divestitures	**(3,937)**	(7,436)	5,226	66,004	(322)	(62,752)	(37)	(9)
Net debt	**1,734,284**	1,748,805	1,819,387	1,850,909	1,773,541	1,864,022	1,942,538	1,981,343
Total assets	**4,372,111**	4,353,637	4,582,049	4,702,423	4,594,085	4,995,876	5,089,280	5,197,913
Common shares outstanding	**235,451**	235,451	234,204	234,203	233,449	211,542	210,715	210,689
Daily production								
Total production (boe/d)	**69,556**	69,310	72,812	69,298	65,136	67,167	70,031	75,776
Canada (boe/d)	**32,194**	34,560	34,284	33,217	31,704	33,615	31,722	34,709
U.S. (boe/d)	**37,362**	34,750	38,528	36,081	33,432	33,552	38,309	41,067
Benchmark prices								
WTI oil (US$/bbl)	**55.40**	48.20	48.28	51.91	49.29	44.94	45.60	33.45
WCS heavy (US$/bbl)	**43.14**	38.26	37.16	37.34	34.97	31.44	32.29	19.22
CAD/USD avg exchange rate	**1.2717**	1.2524	1.3447	1.3229	1.3339	1.3051	1.2885	1.3748
AECO gas ($/mcf)	**1.96**	2.04	2.77	2.94	2.81	2.20	1.25	2.11
NYMEX gas (US$/mmbtu)	**2.93**	3.00	3.18	3.32	2.98	2.81	1.95	2.09
Sales price ($/boe)	**44.75**	38.04	39.41	40.16	38.16	31.73	30.52	21.93
Royalties ($/boe)	**10.86**	8.65	9.06	9.17	9.28	7.37	6.65	5.02
Operating expense ($/boe)	**10.91**	10.10	10.70	10.28	9.96	9.07	8.67	10.11
Transportation expense ($/boe)	**1.20**	1.46	1.35	1.29	1.30	1.38	0.81	0.98
Operating netback ($/boe)	**21.78**	17.83	18.30	19.42	17.62	13.91	14.39	5.82
Financial derivatives gain ($/boe)	**0.30**	0.44	0.40	0.04	1.62	3.04	3.74	6.47
Operating netback after financial derivatives ($/boe)	**22.08**	18.27	18.70	19.46	19.24	16.95	18.13	12.29

Our operating and financial results have improved as oil prices continue to recover from the multi-year lows experienced in early 2016. Compliance with OPEC's production quotas and increased global demand for crude oil have resulted in the WTI benchmark gradually increasing from US$33.45/bbl in Q1/2016 to US$55.40/bbl in Q4/2017. We increased our capital activity in Canada and the U.S. in Q4/2016 as the outlook for oil price improved after reducing capital activity in response to the low commodity price environment. Our exploration and development expenditures continue to be focused on our Eagle Ford properties as these assets generate our highest netbacks and rates of return. In Canada, exploration and development activity was higher in 2017 after deferring operated heavy oil drilling during the first nine months of 2016. The increased level of activity has increased production in 2017 from, after dispositions completed in 2016 and lower capital investment resulted in declining quarterly production through the end of 2016. Adjusted funds flow is directly impact by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow improved in 2017 as commodity prices recovered and our daily production increased from 2016. Net debt has decreased from $2.0 billion at Q1/2016 to $1.7 billion at Q4/2017 primarily due to the strengthening of the Canadian dollar relative to the U.S. dollar which has decreased the reported amount of our U.S. dollar denominated debt.

FOURTH QUARTER OF 2017

We delivered strong operating and financial results in Q4/2017. Production averaged 69,556 boe/d in Q4/2017 and contributed to our annual production of 70,242 boe/d which exceeded the high end of our annual guidance range of 69,500-70,000 boe/d. Average daily production in Q4/2017 was 7% higher than 65,136 boe/d reported for Q4/2016 due to our successful 2017 capital program and strong production results. Adjusted funds flow of $105.8 million for Q4/2017 increased relative to $77.2 million in Q4/2016 as a result of our solid operating results and an improvement in commodity prices.

In the Eagle Ford, production averaged 37,362 boe/d in Q4/2017 which is an increase of 12% from 33,432 boe/d in Q4/2016. Continued strong well results from enhanced completion techniques resulted in higher initial production rates from wells that commenced production in 2017 compared to 2016 which contributed to the higher average production relative to Q4/2016. In addition, the pace of development slowed in Q2/2016 and Q3/2016 which contributed to a decline in production in the last half of 2016 before the pace of development increased again in Q4/2016. Capital expenditures in the Eagle Ford were $48.3 million in Q4/2017 as we maintained the pace of development and drilled 37 (7.6 net) wells and placed 25 (5.4 net) wells on production during the quarter.

In Canada, production for Q4/2017 averaged 32,194 boe/d which is 2% higher than 31,704 boe/d in Q4/2016. The acquisition of the Peace River properties in Q1/2017 along with the positive well results from our 2017 capital program contributed to the increased production which offset natural declines. Capital expenditures were $41.9 million in Q4/2017 and included $24.6 million on drilling and completion costs for 26 (13.4 net) wells and $15.3 million on pipelines and facilities which included initial costs for construction of a gas plant which will support growth in our expanded position in Peace River.

Operating netback per boe increased to $21.78/boe for Q4/2017 from $17.62/boe in Q4/2016 primarily due to the increase in commodity prices. The WTI benchmark price averaged US$55.40/bbl in Q4/2017 compared to US$49.29/bbl in 2016 and the LLS benchmark increased to US$60.50/bbl in Q4/2017 compared to US$49.95/bbl in Q4/2016. The increase in oil prices increased our realized sales price, net of blending by $6.59/boe which was offset by higher royalties per boe and an increase in operating costs per boe from the Q1/2017 Peace River acquisition and from the reactivation of higher operating costs wells that were shut-in for a portion of 2016.

We generated adjusted funds flow of $105.8 million in Q4/2017 which is $28.6 million higher than $77.2 million in Q4/2016. The increase relative to Q4/2016 was primarily driven by higher commodity prices and average daily production in Q4/2017 relative to the comparative period. The increase in total sales, net of blending in was offset by higher royalties associated with higher revenues and higher operating costs from the additional production volumes. Higher operating netback in Q4/2017 was offset by smaller hedging gains and certain other expenses relative to the fourth quarter of 2016 and resulted in a $28.6 million increase in adjusted funds flow.

We recorded net income of $76.0 million in Q4/2017 compared to a net loss of $359.4 million in Q4/2016. The change in net income is primarily related to $396.6 million of impairment expense recorded in Q4/2016 as compared to no impairment expense recorded during 2017. The change in net income was also due to lower foreign exchange gains and lower gains on disposition of oil and gas properties in Q4/2017 relative to the comparative period.

The following table provides select operating results for Q4/2017.

	Three Months Ended December 31					
	2017			2016		
($ thousands, except as noted)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Heavy oil (bbl/d)	**24,945**	**—**	**24,945**	22,982	—	22,982
Light oil and condensate (bbl/d)	**882**	**20,347**	**21,229**	1,281	18,882	20,163
NGL (bbl/d)	**987**	**8,885**	**9,872**	1,307	7,012	8,319
Natural gas (mcf/d)	**32,284**	**48,779**	**81,063**	36,804	45,228	82,032
Total production (boe/d)	**32,194**	**37,362**	**69,556**	31,704	33,432	65,136
Baytex Average Sales Prices						
Canadian heavy oil ($/bbl)[(1)]	**$ 42.03**	**$ —**	**$ 42.03**	$ 34.33	$ —	$ 34.33
Light oil and condensate ($/bbl)	**62.47**	**73.08**	**72.64**	55.16	60.45	60.12
NGL ($/bbl)	**28.89**	**29.16**	**29.14**	18.50	23.41	22.64
Natural gas ($/mcf)	**1.72**	**3.67**	**2.89**	2.78	4.28	3.61
Weighted average ($/boe)[(2)]	**$ 36.89**	**$ 51.53**	**$ 44.75**	$ 31.10	$ 44.84	$ 38.16
Operating netback ($/boe)						
Sales, net of blending expense	**$ 36.89**	**$ 51.53**	**$ 44.75**	$ 31.10	$ 44.84	$ 38.16
Less:						
Royalties	**5.72**	**15.30**	**10.86**	4.82	13.52	9.28
Operating expenses	**16.57**	**6.04**	**10.91**	13.10	6.98	9.96
Transportation expenses	**2.59**	**—**	**1.20**	2.67	—	1.30
Operating netback	**$ 12.01**	**$ 30.19**	**$ 21.78**	$ 10.51	$ 24.34	$ 17.62
Financial derivatives gain	**$ —**	**$ —**	**$ 0.30**	$ —	$ —	$ 1.62
Operating netback after financial derivatives	**$ 12.01**	**$ 30.19**	**$ 22.08**	$ 10.51	$ 24.34	$ 19.24
Capital Expenditures						
Exploration and development	**$ 41,864**	**$ 48,292**	**$ 90,156**	$ 12,151	$ 55,878	$ 68,029
Acquisitions, net of divestitures	**$ (3,937)**	**$ —**	**$ (3,937)**	$ (218)	$ (104)	$ (322)

(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 the table excludes the impact of financial derivatives.

(2) Realized heavy oil prices are calculated based on sales volumes, net of blending costs.

2018 GUIDANCE

We announced our 2018 capital budget of $325 to $375 million and production guidance of 68,000 to 72,000 boe/d in December 2017. The 2018 capital budget is approximately 60% weighted to the first half of the year and we have the operational flexibility to adjust our spending plans based on changes in the commodity price environment. This budget is weighted to drilling and completion activities (approximately 83%) with the balance for facilities (approximately 16%) and land and seismic (approximately 1%).

Based on the mid-point of our production guidance range of 70,000 boe/d, approximately 51% of our production is expected to be generated in the Eagle Ford with the remaining 49% from Canada. Our production mix is forecast to be 80% liquids (38% heavy oil, 30% light oil and condensate and 12% natural gas liquids) and 20% natural gas.

Our 2018 capital plans include approximately $30 million of non-recurring infrastructure investment in Peace River and Lloydminster to support future development and growth. This includes costs related to our 50% working interest in a 18 mmcf/d natural gas plant and related pipeline infrastructure in Peace River as part of our gas conservation strategy. It also includes pipelines, compression and road construction on our acquired Peace River lands where we expect to drill multi-lateral horizontal wells in the Seal region. We have also planned an expansion of our Kerrobert thermal facility to accommodate a steam-assisted gravity drainage program in 2018 and 2019.

2018 Guidance

Exploration and development capital	$325-$375 million
Production	68,000 to 72,000 boe/d
Expenses:	
Royalty rate	approximately 23%
Operating	$10.50-$11.25/boe
Transportation	$1.35-$1.45/boe
General and administrative	approximately $44 million or $1.72/boe
Interest	approximately $100 million or $3.95/boe

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at December 31, 2017, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES 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, NGL 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</u>

The Company's capital 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 Indicators</u>

Judgment is required to assess when indicators of impairment or impairment reversal exist and when calculation of 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.

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 and future abandonment and reclamation obligations. Any changes to these estimates and assumptions could impact the calculation of recoverable amount and the carrying value of assets.

Exploration and Evaluation Assets ("E&E")

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 International Financial Reporting Standards ("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.

Financial Derivatives

Financial derivatives are measured at fair value on each reporting date. The Company uses estimates of future commodity prices 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 amounts recorded for asset retirement obligations are based on the Company's net ownership interest in wells and facilities, 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.

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.

Legal

The Company is engaged in litigation and claims arising in the normal course of operations where the actual outcome may vary from the amount recognized in the consolidated financial statements. None of these claims are expected to materially affect the Company's financial position or reported results of operations.

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 in the Company's provision for income taxes. Estimates of future income taxes are subject to measurement uncertainty.

CURRENT AND FUTURE CHANGES IN ACCOUNTING POLICIES

Revenue from Contracts with Customers

In April 2016, the International Accounting Standards Board ("IASB") issued its final amendments to IFRS 15 *Revenue from Contracts with Customers,* which will replace IAS 11 *Construction Contracts* and IAS 18 *Revenue* and the related interpretations on revenue recognition. The new standard moves away from a revenue recognition model based on an earnings process to an approach that is based on transfer of control of a good or service to a customer. The standard also requires extensive new disclosures, as to the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. IFRS 15 can be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. The new standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The Company has substantially completed its review of the various revenue streams and underlying contracts with customers and does not anticipate a material impact to the Company's net income. The Company will expand the disclosures in the notes to the financial statements as prescribed by IFRS 15 to provide additional information on the Company's various revenue streams and contractual arrangements.

Financial Instruments

In July 2014, the IASB issued IFRS 9 *Financial Instruments* which is intended to replace IAS 39 *Financial Instruments: Recognition and Measurement*. The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classifications: amortized cost and fair value. 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 (loss) rather than net income (loss). The new standard also introduces a credit loss model for evaluating impairment of financial assets. In addition, IFRS 9 provides a hedge accounting model that is more in line with risk management activities. The Company currently does not apply hedge accounting to its derivative contracts nor does it intend to apply hedge accounting upon adoption of IFRS 9. The standard is effective for annual periods beginning on or after January 1, 2018 with early adoption permitted. The Company will adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The Company has concluded that the standard will not have a material impact on the consolidated financial statements.

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 (loss). The standard is effective for annual periods beginning on or after January 1, 2019 with early adoption permitted if IFRS 15 has been adopted. The standard shall be applied retrospectively to each period presented or retrospectively as a cumulative-effect adjustment as of the date of adoption. IFRS 16 will be applied by Baytex on January 1, 2019. The Company is developing a plan to identify and review its various lease agreements in order to determine the impact that adoption of IFRS 16 will have on the consolidated financial statements.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2017, 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 Chief Executive Officer and the 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, 2017. The effectiveness of our internal control over financial reporting as of December 31, 2017 has been audited by KPMG LLP, as reflected in their report for 2017.

Changes in Internal Control Over Financial Reporting

No changes were made to our internal control over financial reporting during the year ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, the internal controls over financial reporting.

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 risk and uncertainties. Further information regarding risks and uncertainties affecting our business is contained in our Annual Information Form for the year ended December 31, 2017 under the "Risk Factors" section.

Volatility of Oil and Natural Gas Prices

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 foreign supply of crude oil, the price of foreign imports, 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 converted to 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. The supply of Canadian crude oil with demand from the refinery complex and access to those markets through various transportation outlets is currently finely balanced and, therefore, very sensitive to pipeline and refinery outages, which contributes to this volatility.

Decreases to or a prolonged period 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 Canadian GAAP. If crude oil and natural gas forecast prices decline further, it could result in downward revisions to the carrying value of our assets and our net earnings could be adversely affected.

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 the lack of financing and uncertainty in the capital markets adversely impact our ability to refinance debt, additional equity may be issued resulting in a dilutive effect on current and future shareholders.

Our ability to obtain additional capital is dependent on, among other things, investor interest in the energy industry in general, interest in our securities in particular and 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.

Debt Service and Refinancing

We are required to comply with covenants under the Revolving Facilities and our long-term notes. In the event that we do not comply with these covenants, our access to capital (including our ability to make borrowings under the Revolving Facilities) could be restricted or repayment could be required on an accelerated basis by our lenders.

Our existing Revolving Facilities and any replacement facilities may not provide sufficient liquidity. We currently have Revolving Facilities in the amount of US$575 million. The amounts available under our existing Revolving Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms attractive to us, if at all. There can be no assurance that the amount of our Revolving Facilities will be adequate for our future financial obligations, including our future capital expenditure program, 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 our ongoing operations. In the event that the Revolving Facilities are not extended before June 2019, indebtedness under the Revolving Facilities will be repayable at that time. In addition, we are required to repay the long-term notes on maturity. There is a risk that the Revolving Facilities will not be renewed for the same amount or on the same terms.

Debt Covenant Compliance

We are required to comply with the covenants in our Revolving 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.

Non-operating Agreements in the U.S.

Marathon Oil EF LLC ("Marathon Oil"), a wholly-owned subsidiary of Marathon Oil Corporation, is the operator of our Eagle Ford acreage and we will be reliant upon Marathon Oil to operate successfully. Marathon Oil will make decisions based on its own best interests and the collective best interests of all of the working interest owners of this acreage, which may not be in our best interests. 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 and development 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.

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.

Public perception and influence on 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 impede our business or make our operations more expensive.

Environmental Regulation and Risk

The oil and natural gas industry is currently subject to environmental regulations pursuant to a variety of federal, provincial and state legislation, all of which is subject to governmental review and revision from time to time. Such legislation provides for restrictions and prohibitions on the release or emission of various substances produced in association with certain oil and gas industry operations. In addition, such legislation sets out the requirements with respect to oilfield waste handling and storage, habitat protection and the satisfactory operation, maintenance, abandonment and reclamation of well and facility sites. Compliance with such legislation can require significant expenditures and a breach of such requirements may result in suspension or revocation of necessary licenses and authorizations, civil liability for pollution damage and the imposition of material fines and penalties. Further, environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. Although we believe that we will be in material compliance with current applicable environmental legislation, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on our business, financial condition, results of operations and prospects.

Climate Change Regulation

Both Canada and the United States are signatories to the United Nations Framework Convention on Climate Change (the "UNFCCC") and are participants in the Copenhagen Accord (a non-binding agreement created by the UNFCCC which represents a broad political consensus and reinforces commitments to reducing greenhouse gas ("GHG") emissions). Both governments agreed to an economy-wide target to reduce GHG emissions by 17% from 2005 levels. Both governments also signed the Paris Agreement in December of 2015, which included a commitment to keep any increase in global temperatures below two degrees Celsius. Canada pledged to reduce GHG emissions by 30% by 2030 from 2005 levels. The United States has since announced it intends to withdraw from the Paris Agreement.

The Government of Canada has announced that it intends to implement a carbon tax in 2018 starting at $10/tonne and rising by $10/tonne a year to $50/tonne by 2022. This federal carbon tax is intended to be implemented in concert with the provinces and territories and would only be implemented in those provinces and territories that do not have their own carbon tax.

The Province of Alberta announced and implemented a broad range of plans targeting GHG emissions that include: a carbon levy of $20/tonne effective January 1, 2017, which increased to $30/tonne on January 1, 2018; a cap on GHG emissions from the oil sands of 100 mega tonnes per year; and a plan to introduce regulations that will reduce methane emissions from oil and gas operations by 45% by 2025. The Province of Saskatchewan has set forth similar legislation that is not yet in force for facilities that emit more than 50,000 tonnes of GHGs per year. At present, we do not operate any facilities in Alberta or Saskatchewan that exceed these thresholds.

Variations in Interest 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.

Variations in Foreign Exchange Rates

World oil prices are quoted in U.S. 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 Revolving Facilities and a large portion of our long-term notes are denominated in U.S. dollars and the interest and principal 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.

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 risk management program. We also use derivative instruments in various operational markets to optimize our supply or production chain. 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 royalties being paid on 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 due to the volatile commodity environment.

Changes to Income tax 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. For further details see "*Income Taxes*".

Reserve Estimates

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. 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.

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.

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.

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; information systems; 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.

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; crude oil and natural gas prices and the price differentials between light, medium and heavy oil prices; our ability to reduce the volatility in our adjusted funds flow by utilizing financial derivative contracts; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; the length of time it would take to resolve the reassessments; that we would owe cash taxes and late payment interest if the reassessment is successful; our expectation regarding the payment of cash income taxes prior to 2022; the sufficiency of our capital resources to meet our on-going short, medium and long-term commitments; the financial capacity of counterparties to honor outstanding obligations to us in the normal course of business; the existence, operation and strategy of our risk management program; our capital budget for 2018; our annual average production rate for 2018; the portion of our 2018 capital budget to be spent in the first half of the year; the breakdown of our 2018 capital budget by expenditure type; the geographic breakdown of our 2018 production; our production mix for 2018; our plans for developing our properties; our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2018; the impact of the adoption of new accounting standards on our financial results; and that we are in material compliance with current applicable environmental legislation. 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: 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; a decline or an extended period of the currently low oil and natural gas prices; uncertainties in the capital markets that may restrict or increase our cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; changes in government regulations that affect the oil and gas industry; changes in environmental, health and safety regulations; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; the cost of developing and operating our assets; availability and cost of gathering, processing and pipeline systems; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating petroleum and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; we may lose access to our information technology systems; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2017, as filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission.

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

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