BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the years ended December 31, 2018 and 2017
Dated March 5, 2019

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

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

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

BAYTEX ENERGY CORP.

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

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

2018 ANNUAL HIGHLIGHTS

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

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

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

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

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

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

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

At December 31, 2018, net debt was $2,265.2 million, an increase of $530.9 million from $1,734.3 million at December 31, 2017. The increase is primarily due to the $363.6 million of net debt assumed on closing of the Strategic Combination combined with a $107.1 million increase in the reported amount of our U.S. dollar denominated debt due to a weaker Canadian dollar at December 31, 2018 compared to December 31, 2017. The precipitous widening of Canadian oil differentials and decline in global benchmark oil prices during Q4/2018 resulted in exploration and development expenditures for November and December 2018 exceeding adjusted funds flow by $76.8 million which also contributed to the increase in net debt relative to December 31, 2017.

GUIDANCE

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

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

(1) Current as of November 2, 2018.

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

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

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

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

RESULTS OF OPERATIONS

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

Production

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

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

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

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

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

Commodity Prices

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

Crude Oil

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

We compare our liquids pricing to the WTI benchmark oil price which is the representative index for inland North American light oil at Cushing, Oklahoma. The WTI benchmark price averaged US$64.77/bbl during 2018, representing an increase of US$13.82/bbl compared to 2017 when the benchmark price averaged US$50.95/bbl.

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

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

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

Natural Gas

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

In Canada, we receive natural gas pricing based on the AECO benchmark which continues to trade at a significant discount to NYMEX as a result of increasing supply and limited market access for Canadian natural gas production. The benchmark averaged $1.54/mcf during 2018 which is $0.89/mcf lower than the benchmark average of $2.43/mcf during 2017.

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

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

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

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) WCS refers to the average posting price for the benchmark WCS heavy oil.
(3) LLS refers to the Argus trade month average for Louisiana Light Sweet oil.
(4) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(5) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

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

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

Average Realized Sales Prices

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

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

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

Our realized heavy oil price, net of blending and other expense averaged $36.20/bbl in 2018 compared to $38.46/bbl in 2017. Our Canadian heavy oil production is blended with diluent in order to meet pipeline transportation specifications. The price received for the blended product is recorded as heavy oil sales revenue while the cost of blending diluent is recorded as blending and other expense. We include the cost of blending diluent in our realized heavy oil sales price in order to compare the realized pricing on our produced volumes to the WCS benchmark. Our realized heavy oil price was negatively impacted by an increase in the cost of blending diluent in 2018. As a result, our realized heavy oil price decreased by $2.26/bbl in 2018 compared to the $0.74/bbl decrease in the WCS benchmark price.

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

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

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

Petroleum and Natural Gas Sales

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

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

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

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

Royalties

Royalties are paid to various government entities and to land and mineral rights owners. Royalties are calculated based on gross revenues or on operating netbacks less capital investment for specific heavy oil projects, and are generally expressed as a percentage of total sales, net of blending and other expense. The actual royalty rates can vary for a number of reasons, including the commodity produced, royalty contract terms, commodity price level, royalty incentives and the area or jurisdiction. The following table summarizes our royalties and royalty rates for the years ended December 31, 2018 and 2017.

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

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

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

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

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

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

Operating Expense

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

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

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

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

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

Transportation Expense

Transportation expense includes the costs to move production from the field to the sales point. The largest component of transportation expense relates to the trucking of oil in Canada to pipeline and rail terminals which can vary from period to period depending on hauling distances as we seek to optimize sales prices and trucking rates. The following table compares our transportation expense for the years ended December 31, 2018 and 2017.

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

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

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

Blending and Other Expense

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

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

Financial Derivatives

As part of our normal operations, we are exposed to movements in commodity prices, foreign exchange rates and interest rates. In an effort to manage these exposures, we utilize various financial derivative contracts which are intended to partially reduce the volatility in our adjusted funds flow. Contracts settled in the period result in realized gains or losses based on the market price compared to the contract price and the notional volume outstanding. Changes in the fair value of unsettled contracts are reported as unrealized gains or losses in the period as the forward markets for commodities and currencies fluctuate and as new contracts are executed. The following table summarizes the results of our financial derivative contracts for the years ended December 31, 2018 and 2017.

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

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

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

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

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

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

	Remaining Period	Volume	Price/Unit[1]	Index
Oil				
Fixed - Sell	Jan 2019 to Jun 2019	2,000 bbl/d	US$62.85/bbl	WTI
3-way option [2]	Jan 2019 to Dec 2019	2,000 bbl/d	US$70.00/US$60.00/US$50.00	WTI
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$72.60/US$65.00/US$55.00	WTI
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$72.50/US$66.00/US$56.00	WTI
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$73.00/US$66.00/US$56.00	WTI
3-way option [2]	Jan 2019 to Dec 2019	2,000 bbl/d	US$73.00/US$67.00/US$57.00	WTI
3-way option [2]	Jan 2019 to Dec 2019	2,000 bbl/d	US$74.00/US$68.00/US$58.00	WTI
3-way option [2]	Jan 2019 to Dec 2019	2,000 bbl/d	US$75.00/US$61.70/US$49.00	WTI
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.00/US$69.90/US$60.00	WTI
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$76.00/US$71.00/US$61.00	WTI
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$78.00/US$73.00/US$63.00	WTI
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$75.50/US$65.50/US$55.50	Brent
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$77.55/US$70.00/US$60.00	Brent
3-way option [2]	Jan 2019 to Dec 2019	1,000 bbl/d	US$83.00/US$73.00/US$63.00	Brent
Basis Swap [3]	Mar 2019 to Jun 2019	2,000 bbl/d	WTI less US$14.75/bbl	WCS
Basis Swap [3]	Apr 2019 to Jun 2019	2,000 bbl/d	WTI less US$13.65/bbl	WCS
Basis Swap [3]	Jul 2019 to Sep 2019	4,000 bbl/d	WTI less US$17.38/bbl	WCS
Basis Swap [3]	Oct 2019 to Dec 2019	4,000 bbl/d	WTI less US$20.88/bbl	WCS
Natural Gas				
Fixed - Sell	Jan 2019 to Mar 2019	5,000 GJ/d	CAD$2.25	AECO
Fixed - Sell	Jan 2019 to Dec 2019	5,000 mmbtu/d	US$3.15	NYMEX
Fixed - Sell	Jan 2019 to Mar 2019	10,000 mmbtu/d	US$3.82	NYMEX
Fixed - Sell	Apr 2019 to Jun 2019	10,000 mmbtu/d	US$2.79	NYMEX
Fixed - Sell	Jul 2019 to Sep 2019	10,000 mmbtu/d	US$2.79	NYMEX
Fixed - Sell	Oct 2019 to Dec 2019	10,000 mmbtu/d	US$2.88	NYMEX

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

Interest Rate Swap

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

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

(1) Canadian Dollar Offered Rate.

Physical Delivery Contracts

The following physical delivery contracts were held for the purpose of delivery of non-financial items in accordance with the Company's expected sale requirements. Physical delivery contracts are not considered financial instruments and, as a result, no asset or liability has been recognized in the consolidated statements of financial position.

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

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

Operating Netback

The following table summarizes our operating netback on a per boe basis for our Canadian and U.S. operations for the years ended December 31, 2018 and 2017.

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

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

General and Administrative Expense

General and administrative ("G&A") expense includes head office and corporate costs such as salaries and employee benefits, public company costs and administrative recoveries earned for operating capital and production activities on behalf of our working interest partners. G&A expense fluctuates with head office staffing levels and the level of operated capital and production activity during the period.

The following table summarizes our G&A expenses for the years ended December 31, 2018 and 2017.

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

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

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

Financing and Interest Expense

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

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

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

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

Exploration and Evaluation Expense

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

Depletion and Depreciation

Depletion and depreciation expense varies with the carrying amount of the Company's oil and gas properties, the amount of proved plus probable reserves volumes and the rate of production for the period. The following table summarizes depletion and depreciation expense for the years ended December 31, 2018 and 2017.

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

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

Impairment

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

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

Share-Based Compensation Expense

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

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

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

Foreign Exchange

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

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

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

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

Income Taxes

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

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

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

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

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

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

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

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

Net Income (Loss) and Adjusted Funds Flow

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

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

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

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

Other Comprehensive Income (Loss)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets not recognized in profit or loss. The $204.8 million foreign currency translation gain for 2018 relates to the change in value of our U.S. net assets expressed in Canadian dollars and is due to the weakening of the Canadian dollar against the U.S. dollar. The CAD/USD exchange rate was 1.3646 as at December 31, 2018 compared to 1.2518 as at December 31, 2017.

Capital Expenditures

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

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

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

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

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

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

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

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

CAPITAL RESOURCES AND LIQUIDITY

Our capital management objective is to maintain a flexible capital structure and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions and the risk characteristics of our oil and gas properties. At December 31, 2018, our capital structure was comprised of shareholders' capital, long-term notes, working capital and our bank loan.

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

Management of debt levels is a priority for Baytex in order to sustain operations and support our plans for long-term growth. At December 31, 2018, net debt was $2,265.2 million, an increase of $530.9 million from $1,734.3 million at December 31, 2017. The increase in net debt is primarily due to $363.6 million of net debt assumed in conjunction with the Strategic Combination on August 22, 2018. A weaker Canadian dollar at December 31, 2018 also increased the reported amount of our U.S. denominated debt by $107.1 million relative to December 31, 2017.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio and available capacity under our credit facilities. At December 31, 2018, our net debt to adjusted funds flow ratio was 3.1, after adjustment for the Strategic Combination as if the transaction had occurred on the first day of the relevant period, compared to a ratio of 5.0 as at December 31, 2017. The decrease in the net debt to adjusted funds flow ratio relative to December 31, 2017 is attributed to higher adjusted funds flow from higher commodity prices combined with the increase in average daily production. The effect of higher adjusted funds flow more than offset the impact of the increase in net debt as at December 31, 2018.

Bank Loan

At December 31, 2018, the principal amount of bank loan and letters of credit outstanding was $536.9 million and we had approximately $547.7 million of undrawn capacity under our credit facilities that total approximately $1,084.6 million. Our facilities include US$575 of revolving credit facilities (the "Revolving Facilities") and a CAD$300 million non-revolving term loan (the "Term Loan").

On August 22, 2018, Baytex amended its credit facilities to facilitate the Strategic Combination and the debt assumed from Raging River. The Revolving Facilities are secured and are comprised of a US$35 million operating loan, a US$340 million syndicated revolving loan for Baytex and a US$200 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. and matures on June 4, 2020. The Term Loan is secured by the assets of Baytex's wholly-owned subsidiary, Baytex Energy Limited Partnership and also matures on June 4, 2020. We anticipate requesting an extension to our credit facilities during 2019.

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

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

The weighted average interest rate on the credit facilities for 2018 was 4.3% as compared to 4.1% for 2017.

Financial Covenants

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

Covenant Description	Position as at December 31, 2018	Covenant
Senior Secured Debt[(1)] to Bank EBITDA[(2)] (Maximum Ratio)	**0.64:1.00**	3.50:1.00
Interest Coverage[(3)] (Minimum Ratio)	**8.00:1.00**	2.00:1.00

(1) "Senior Secured Debt" is defined as the principal amount of the bank loan and other secured obligations identified in the credit agreement. As at December 31, 2018, the Company's Senior Secured Debt totaled $536.9 million which includes $522.3 million of principal amounts outstanding and $14.6 million of letters of credit.

(2) Bank EBITDA is calculated based on terms and definitions set out in the credit agreement which adjusts net income or loss for financing and interest expenses, unrealized gains and losses on financial derivatives, income tax, non-recurring losses, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, unrealized gains and losses on financial derivatives and foreign exchange and share-based compensation) and is calculated based on a trailing twelve month basis including the impact of material acquisitions as if they had occurred at the beginning of the twelve month period. Bank EBITDA for the twelve months ended December 31, 2018 was $833.7 million.

(3) Interest coverage is computed as the ratio of Bank EBITDA to financing and interest expense, excluding non-cash interest and accretion on asset retirement obligations, and is calculated on a trailing twelve month basis. Financing and interest expenses for the twelve months ended December 31, 2018 were $104.3 million.

Long-Term Notes

We have four series of long-term notes outstanding that total $1.60 billion as at December 31, 2018. The long-term notes do not contain any significant financial maintenance covenants. The long-term notes contain a debt incurrence covenant that restricts our ability to raise additional debt beyond existing credit facilities and long-term notes unless we maintain a minimum fixed charge coverage ratio (computed as the ratio of Bank EBITDA to financing and interest expenses on a trailing twelve month basis) of 2.50:1.00. As at December 31, 2018, the fixed charge coverage ratio was 8.00:1.00.

On February 17, 2011, we issued US$150 million principal amount of senior unsecured notes bearing interest at 6.75% payable semi-annually with principal repayable on February 17, 2021. These notes are redeemable at our option, in whole or in part, at par from February 17, 2019 to maturity.

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

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

Shareholders' Capital

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

Contractual Obligations

We have a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact our adjusted funds flow in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2018 and the expected timing for funding these obligations are noted in the table below.

($ thousands)	**Total**	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Trade and other payables	**$ 258,114**	$ 258,114	$ —	$ —	$ —
Bank loan[(1)] [(2)]	**522,294**	—	522,294	—	—
Long-term notes[(2)]	**1,596,323**	—	750,503	300,000	545,820
Interest on long-term notes[(3)]	**334,028**	92,367	156,525	72,350	12,786
Operating leases	**22,745**	7,484	12,492	2,753	16
Processing agreements	**47,717**	10,926	15,526	9,039	12,226
Transportation agreements	**112,002**	14,398	42,054	19,821	35,729
Total	**$ 2,893,223**	$ 383,289	$ 1,499,394	$ 403,963	$ 606,577

(1) The bank loan matures on June 4, 2020 unless maturity is extended at our request.
(2) Principal amount of instruments.
(3) Excludes interest on bank loan as interest payments on bank loans fluctuate based on interest rate and bank loan balance.

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

FOURTH QUARTER 2018 OPERATING AND FINANCIAL RESULTS

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

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

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

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

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) WCS refers to the average posting price for the benchmark WCS heavy oil.
(3) LLS refers to the Argus trade month average for Louisiana Light Sweet oil.
(4) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(5) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

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

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

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

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

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

QUARTERLY FINANCIAL INFORMATION

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

Our operating and financial results have improved as oil prices continue to recover from the multi-year lows experienced in 2016. Compliance with OPEC's production quotas and increased global demand for crude oil resulted in the WTI benchmark gradually increasing from US$51.91/bbl in Q4/2016 to US$69.50/bbl during Q3/2018 before global geopolitical factors caused a decline to $58.81/bbl in Q4/2018. Improved well productivity from enhanced completion techniques contributed to the increase in daily production in the U.S. with a reduction in quarterly exploration and development expenditures. In Canada, exploration and development activity increased in 2018. The increased level of activity along with the Strategic Combination in Q3/2018 has increased production from Q1/2017 into Q4/2018. Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow began to improve in late 2017 as commodity prices recovered and increased through Q3/2018 with higher production due to strong well performance along with the Strategic Combination. Adjusted funds flow was impacted by a significant widening of Canadian oil differentials in Q4/2018.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt has increased from $1,850.9 million at Q1/2017 to $2,265.2 million at Q4/2018 primarily due to the additional net debt of $363.6 million assumed in conjunction with the Strategic Combination in Q3/2018.

OFF BALANCE SHEET TRANSACTIONS

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

CRITICAL ACCOUNTING ESTIMATES

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

<u>Reserves</u>

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

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

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

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

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

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

<u>Measurement of Recoverable Amount</u>

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

Exploration and Evaluation ("E&E") Assets

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

Business Combinations

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

Joint Arrangements

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

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

Financial Derivatives

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

Asset Retirement Obligations

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

Income Taxes

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

CURRENT AND FUTURE CHANGES IN ACCOUNTING POLICIES

Changes in significant accounting policies

Revenue from contracts with customers

Baytex adopted IFRS 15 Revenue from Contracts with Customers with a date of initial application of January 1, 2018, using the retrospective method. Baytex recognizes revenue when control of the product transfers to the customer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon. The standard also requires new disclosure, as to the nature, amount, timing and uncertainty of revenues and cash flows arising from contracts with customers. Baytex analyzed its revenue streams and its contracts with customers on adoption.

For the year ended December 31, 2017, $8.3 million of commodity purchases related to heavy oil sales have been reclassified from petroleum and natural gas sales to blending and other expense to conform to the requirements of IFRS 15. There were no adjustments made to the January 1, 2018 opening statement of financial position on adoption. The additional disclosures required by IFRS 15 are provided in note 13 to the consolidated financial statements.

Financial instruments

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

The adoption of this standard did not result in a change in the recognition or measurement of any of the Company's financial instruments on transition. The table summarizes the change in classification categories for Baytex's financial assets and liabilities.

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

Future Accounting Pronouncements

Leases

In January 2016, the IASB issued IFRS 16 *Leases* which replaces IAS 17 *Leases.* IFRS 16 introduces a single recognition and measurement model for lessees, which will require recognition of lease assets and lease obligations on the balance sheet. Short-term leases and leases for low value assets are exempt from recognition and may be treated as operating leases and recognized through net income or loss. The standard is effective for annual periods beginning on or after January 1, 2019. IFRS 16 is required to be adopted either retrospectively or using the modified retrospective approach. The Company will adopt IFRS 16 on January 1, 2019 using the modified retrospective method. The modified retrospective approach does not require restatement of prior period comparative financial information as the Company will record the cumulative effect of applying the standard as an increase to right of use assets with a corresponding increase to lease obligations. The Company is currently in the process of quantifying the impact of the contracts that fall within the scope of IFRS 16. The Company expects adjustments for its office lease and the related subleases, field office leases, certain vehicles and field equipment, however, the full extent of the impact has not yet been finalized.

NON-GAAP AND CAPITAL MEASUREMENT MEASURES

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

Adjusted Funds Flow

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

Adjusted funds flow should not be construed as an alternative to performance measures determined in accordance with GAAP, such as cash flow from operating activities and net income or loss.

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

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

Exploration and Development Expenditures

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

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

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

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

Net Debt

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

The following table summarizes our calculation of net debt.

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

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

Operating Netback

We define operating netback as petroleum and natural gas sales, less blending expense, royalties, operating expense and transportation expense. Operating netback per boe is the operating netback divided by barrels of oil equivalent production volume for the applicable period. We believe that this measure assists in assessing our ability to generate cash margin on a unit of production basis and is a key measure used to evaluate our operating performance.

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

Bank EBITDA

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

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

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

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

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

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

Internal Control Over Financial Reporting

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

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

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

In accordance with the provisions of NI 52-109 and consistent with SEC guidance, the scope of the evaluation did not include internal controls over financial reporting of Raging River. On August 22, 2018, Baytex completed the acquisition of Raging River, a publicly traded oil and gas company that was listed on the Toronto Stock Exchange. Raging River's operations have been included in the consolidated financial statements of Baytex since August 22, 2018. However, Baytex has not had sufficient time to appropriately assess the disclosure controls and procedures and internal controls over financial reporting previously used by Raging River and integrate them with those of Baytex. In addition, Raging River was not subject to the Sarbanes-Oxley Act of 2002 and, therefore, was not required to have its external auditors audit the effectiveness of its internal control over financial reporting. As a result, the certifying officers have limited the scope of their design of disclosure controls and procedures and internal controls over financial reporting to exclude controls, policies and procedures of Raging River (as permitted by applicable securities laws in Canada and the U.S.). Baytex has a program in place to complete its assessment of the controls, policies and procedures of the acquired operations by August 22, 2019.

During the year ended December 31, 2018, the assets previously held by Raging River contributed revenues, net of royalties of $142.3 million. At December 31, 2018, total assets of $2.1 billion were associated with the acquired entity.

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

Changes in Internal Control over Financial Reporting

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

SELECTED ANNUAL INFORMATION

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

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

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; the percentage of production from the Raging River properties that is high operating netback light oil; our capital budget and expected average daily production for 2019; and our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2019; our expected price realizations for Canadian light oil; the existence, operation and strategy of our risk management program; the reassessment of our tax filings by the Canada Revenue Agency; our intention to defend the reassessments; our view of our tax filing position; the length of time it would take to resolve the reassessments; that we would owe cash taxes and late payment interest if the reassessment is successful; that our internally generated adjusted funds flow *and our existing undrawn credit facilities will provide sufficient liquidity to sustain our operations and planned capital expenditures; that a significant portion of our financial obligations will be funded by adjusted funds flow; the expected impact on total assets and total liabilities and net income before income tax of adopting IFRS 16 and our plan to complete an assessment of the controls, policies and procedures associated with Raging River by August 22, 2019. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.*

These forward-looking statements are based on certain key assumptions regarding, among other things: the timing of receipt of regulatory and shareholder approvals for the Transaction; the ability of the combined company to realize the anticipated benefits of the Transaction; petroleum and natural gas prices and differentials between light, medium and heavy oil prices; well production rates and reserve volumes; our ability to add production and reserves through our exploration and development activities; capital expenditure levels; our ability to borrow under our credit agreements; the receipt, in a timely manner, of regulatory and other required approvals for our operating activities; the availability and cost of labour and other industry services; interest and foreign exchange rates; the continuance of existing and, in certain circumstances, proposed tax and royalty regimes; our ability to develop our crude oil and natural gas properties in the manner currently contemplated; and current industry conditions, laws and regulations continuing in effect (or, where changes are proposed, such changes being adopted as anticipated). Readers are cautioned that such assumptions, although considered reasonable by Baytex at the time of preparation, may prove to be incorrect.

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials; availability and cost of gathering, processing and pipeline systems; failure to comply with the covenants in our debt agreements; the availability and cost of capital or borrowing; that our credit facilities may not provide sufficient liquidity or may not be renewed; risks associated with a third-party operating our Eagle Ford properties; the cost of developing and operating our assets; depletion of our reserves; risks associated with the exploitation of our properties and our ability to acquire reserves; new regulations on hydraulic fracturing; restrictions on or access to water or other fluids; changes in government regulations that affect the oil and gas industry; regulations regarding the disposal of fluids; changes in environmental, health and safety regulations; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; changes in income tax or other laws or government incentive programs; uncertainties associated with estimating oil and natural gas reserves; our inability to fully insure against all risks; risks of counterparty default; risks associated with acquiring, developing and exploring for oil and natural gas and other aspects of our operations; risks associated with large projects; risks related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; risks associated with the ownership of our securities, including changes in market-based factors; risks for United States and other non-resident shareholders, including the ability to enforce civil remedies, differing practices for reporting reserves and production, additional taxation applicable to non-residents and foreign exchange risk; and other factors, many of which are beyond our control. These and additional risk factors are discussed in our Annual Information Form, Annual Report on Form 40-F and Management's Discussion and Analysis for the year ended December 31, 2018, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2019 and in our other public filings.

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

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

RISK FACTORS

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

Volatility of oil and natural gas prices and price differentials

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

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

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

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

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

Access to transportation capacity

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

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

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

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

Debt covenant compliance

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

Access to capital markets

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

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

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

Debt service and refinancing

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

Non-operating agreements in the U.S.

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

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

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

Cost of development and operations

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

Reserves are a depleting resource

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

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

Reserves

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

Hydraulic fracturing

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

Water use

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

Government controls, legislation or regulation

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

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

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

Regulations regarding the disposal of fluids

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

Environmental, health and safety controls, legislation or regulations

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

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

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

Public perception and influence on the regulatory regime

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

Climate change initiatives

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

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

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

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

Interest rates and foreign exchange rates

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

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

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

Risk management

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

Income tax laws and other laws

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

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

Reserves Estimates

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

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

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

Insurance

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

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

Credit risk

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

Additional business risks

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

Large projects

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

Thermal heavy oil projects

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

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

Demand for petroleum products

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

Information technology risks

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