BAYTEX ENERGY CORP.
Management's Discussion and Analysis
For the years ended December 31, 2020 and 2019
Dated February 24, 2021

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, 2020 and 2019. This information is provided as of February 24, 2021. 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, 2020 ("Q4/2020" and "2020") have been compared with the results for the three months and year ended December 31, 2019 ("Q4/2019" and "2019"). 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, 2020 and 2019, together with the accompanying notes and the Annual Information Form for the year ended December 31, 2020. 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", "free cash flow", "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 our 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 ("U.S"). 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.

CURRENT ENVIRONMENT

In March 2020, the World Health Organization declared a global pandemic related to the novel coronavirus ("COVID-19"). The emergence of COVID-19 and the steps taken by governments to control the spread of the virus resulted in significant instability in the global economy and a sharp decline in demand for crude oil. This combined with the increased supply of crude oil due to the Russia and Saudi Arabia price war resulted in an unprecedented collapse in global crude oil prices and significant volatility during Q2/2020. Global crude oil prices began to recover during the second half of 2020 as Russia and members of OPEC (collectively, "OPEC+") agreed to curtail production and governments began to ease restrictions which increased demand. In Q4/2020 vaccines were approved and distribution began which fueled further optimism that demand will be restored. Vaccine approval and distribution has continued in 2021 and OPEC+ has agreed to continue production curtailments which has resulted in recent improvements in crude oil prices in 2021.

During 2020, we took significant action in response to COVID-19 and the uncertain outlook for our industry. We preserved our financial liquidity by reducing exploration and development expenditures, limiting discretionary spending and shutting-in low margin production when operating netbacks were challenged. As a result 2020 production and capital spending were lower than 2019. Despite lower production and volatile commodity prices we generated free cash flow of $18.1 million during 2020 which reflects the success of our cost savings initiatives and the disciplined execution of our capital programs. We also maintained $367.2 million of availability on our credit facilities at December 31, 2020.

2020 ANNUAL HIGHLIGHTS

Our financial and operating results for 2020 reflect the challenging market conditions caused by the COVID-19 pandemic. Q1/2020 included an active capital program with commodity prices remaining fairly consistent with 2019, however capital spending was suspended during Q2/2020 as prices collapsed and we focused on reducing costs and preserving our liquidity. We initiated a targeted restart of development activity on our light oil properties in the U.S. and Canada as prices stabilized and the economic outlook improved during the second half of 2020. Exploration and development expenditures of $280.3 million were approximately half of the original budget which resulted in production of 79,781 boe/d for 2020. Despite the volatile commodity prices we were able to generate $18.1 million of free cash flow during 2020 which reflects our focus on cost savings along with the disciplined execution of our capital programs in the U.S. and Canada.

In Q1/2020, we issued US$500 million principal amount of senior unsecured notes. We used the proceeds from the issuance and availability on our credit facilities to redeem the US$400 million principal amount of senior unsecured notes due in 2021 and the $300 million principal amount of senior unsecured notes due in 2022. In addition, we extended the maturity on our credit facilities to April 2, 2024. As a result of these actions, we do not have any debt maturities until 2024 and we had $367.2 million available on our credit facilities at December 31, 2020.

In Canada, production of 48,602 boe/d for 2020 was consistent with expectations after we adjusted development expenditures in response to volatile commodity prices. We were active on our Viking light oil and heavy oil properties during Q1/2020 as the outlook for Canadian oil prices was stable early in the year. After Q1/2020 Canadian development was limited until Q4/2020 when we initiated completions activity on two (2.0 net) light oil wells in the Duvernay and began development of two (2.0 net) wells on our conventional properties as the outlook for light oil and natural gas prices continued to improve. Total exploration and development expenditures of $175.0 million for 2020 included costs associated with drilling 102 (99.2 net) light oil wells in the Viking, 2 (2.0 net) light oil wells in the Duvernay, 33 (33.0 net) heavy oil wells, and 2 (2.0 net) natural gas wells.

In the U.S., we invested $105.4 million on exploration and development activity during 2020 and drilled 65 (16.3 net) wells and initiated production from 62 (14.1 net) wells. Production of 31,179 boe/d was consistent with expectations and reflects moderated completion activity on our Eagle Ford properties during Q2/2020 after the sharp decline in crude oil prices. Activity was restarted during Q3/2020 and was maintained leading into 2021 as the outlook for oil prices improved.

Global benchmark prices for crude oil were volatile during 2020. After a sharp decline in March 2020, oil prices stabilized in the second half of 2020 due to renewed production curtailments by OPEC+ along with improved demand after governments eased restrictions intended to limit the spread of COVID-19. Even with recent improvements, the WTI benchmark price was 31% lower in 2020 relative to 2019 due to elevated global inventory levels and lower demand caused by the COVID-19 pandemic. The WTI benchmark price averaged US$39.40/bbl for 2020 compared to US$57.03/bbl for 2019.

Adjusted funds flow was $311.5 million for 2020 compared to $902.4 million for 2019. Our financial and operating results for 2020 reflect our reduced development activity during a period of low oil prices. Lower crude oil prices were the main factor that lead to a $571.6 million decrease in operating netback relative to 2019. We remained focused on our cost savings initiatives, which resulted in a $93.1 million decrease in operating, transportation, and general and administrative expenses for 2020 compared to 2019. Our net loss of $2.4 billion for 2020 compared to $12.5 million in 2019 reflects impairments of $2.4 billion recorded in 2020 due to the sharp decline in forecasted commodity prices.

Net debt was $1.85 billion at December 31, 2020 which is consistent with $1.87 billion at December 31, 2019. Net debt was reduced with $18.1 million of free cash flow for 2020 along with a $22.4 million decrease in the reported amount of our U.S. dollar denominated public debt due to the strengthening of the Canadian dollar at December 31, 2020 relative to December 31, 2019. These decreases were partially offset by total transaction and financing costs of $17.6 million related to the refinancing transactions in Q1/2020 resulting in the $24.2 million decrease in net debt in 2020 compared to 2019. We had $367.2 million available on our credit facilities at December 31, 2020.

GUIDANCE

The following table compares our 2020 annual guidance to our 2020 results. We delivered production that was consistent with our annual guidance while exploration and development expenditures approximated the mid-point of our guidance range. Expenses, lease expenditures, and settlement of asset retirement obligations were within or slightly below our annual guidance due to our continued efforts to control costs during a period of volatile oil prices.

	Original Annual Guidance (1)	Revised Annual Guidance (2)	2020 Results
Exploration and development expenditures ($ millions)	$500 - $575	$260 - $290	$280.3
Production (boe/d)	93,000 - 97,000	78,000 - 82,000	79,781
Expenses:			
Royalty rate (%)	18.0 - 18.5	18.5	17.7
Operating ($/boe)	$11.25 - $12.00	$11.75 - $12.50	$11.35
Transportation ($/boe)	$1.20 - $1.30	$0.95 - $1.05	$0.97
General and administrative ($ millions)	$45 ($1.30/boe)	$38 ($1.30/boe)	$34.3 ($1.17/boe)
Interest ($ millions)	$112 ($3.23/boe)	$112 ($3.84/boe)	$106.5 ($3.65/boe)
Leasing expenditures ($ millions)	$7	$7	$6
Asset retirement obligations ($ millions)	$19	$10	$7

(1) As announced on December 4, 2019.
(2) As announced on June 25, 2020.

On December 2, 2020 our Board of Directors approved our 2021 capital budget of $225 - $275 million which is designed to generate production of 73,000 - 77,000 boe/d. The program is expected to be equally weighted between the first and second half of 2021 and we will maintain operational flexibility to adjust spending in response to commodity prices.

The following table summarizes our 2021 annual guidance as released on December 2, 2020.

	2021 Guidance
Exploration and development expenditures ($ millions)	$225 - $275
Production (boe/d)	73,000 - 77,000
Expenses:	
Royalty rate (%)	18.0 - 18.5
Operating ($/boe)	$11.50 - $12.25
Transportation ($/boe)	$1.00 - $1.10
General and administrative ($ millions)	$42 ($1.53/boe)
Interest ($ millions)	$105 ($3.84/boe)
Leasing expenditures ($ millions)	$4
Asset retirement obligations ($ millions)	$6

RESULTS OF OPERATIONS

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

Production

	Years Ended December 31					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Daily Production						
Liquids (bbl/d)						
Light oil and condensate	**19,103**	**17,953**	**37,056**	22,358	21,229	43,587
Heavy oil	**21,142**	**—**	**21,142**	26,741	—	26,741
Natural Gas Liquids ("NGL")	**1,224**	**6,116**	**7,340**	1,364	8,865	10,229
Total liquids (bbl/d)	**41,469**	**24,069**	**65,538**	50,463	30,094	80,557
Natural gas (mcf/d)	**42,799**	**42,665**	**85,464**	48,969	53,773	102,742
Total production (boe/d)	**48,602**	**31,179**	**79,781**	58,625	39,055	97,680
Production Mix						
Segment as a percent of total	**61 %**	**39 %**	**100 %**	60 %	40 %	100 %
Light oil and condensate	**39 %**	**58 %**	**46 %**	38 %	54 %	45 %
Heavy oil	**44 %**	**— %**	**27 %**	46 %	— %	27 %
NGL	**3 %**	**20 %**	**9 %**	2 %	23 %	10 %
Natural gas	**14 %**	**22 %**	**18 %**	14 %	23 %	18 %

Production was 79,781 boe/d in 2020 compared to 97,680 boe/d in 2019. Our production results for 2020 were lower relative to 2019 as a result of lower development activity in Canada and the U.S. following the sharp decline in crude oil prices in March 2020.

In Canada, production was 48,602 boe/d in 2020 compared to 58,625 boe/d in 2019. Lower production in 2020 is the result of lower development activity relative to 2019 in addition to temporarily shutting-in production in response to the sharp decline in crude oil prices in March 2020. We brought production back online as prices improved in June 2020 and restarted our development programs as the outlook for oil and natural gas prices improved during Q4/2020.

Production in the U.S. was 31,179 boe/d in 2020 compared to 39,055 boe/d for 2019. Lower production is the result of lower completion activity relative to 2019 as drilling and completion activity was suspended during Q2/2020 and moderated for the remainder of 2020. During 2020 we initiated production from 62 (14.1 net) wells compared to 109 (25.1 net) wells during 2019.

Annual production of 79,781 boe/d for 2020 was in line with expectations and within our annual guidance range of 78,000 - 82,000 boe/d. We expect to sustain production of 73,000 - 77,000 boe/d in 2021 with an objective to maximize free cash flow.

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 were relatively strong leading into 2020 due to a stable outlook for supply and demand. Benchmark prices declined rapidly in March after members of the OPEC+ group began to increase the supply of crude oil to the global market and measures to limit the spread of COVID-19 resulted in a significant decrease in the demand for crude-oil. Global benchmark prices began to improve in July 2020 following the OPEC+ decision to reinstate supply cuts, combined with improved demand after measures intended to limit the spread of COVID-19 were relaxed. Despite the increasing presence of a second wave of COVID-19, prices further improved in Q4/2020 after the first of several vaccines was approved and optimism about the resumption of economic activity improved. Even with the WTI benchmark price increasing in Q4/2020, the benchmark was lower during 2020 and averaged US$39.40/bbl compared to US$57.03/bbl during 2019.

We compare the price received for our U.S. crude oil production to the Magellan East Houston ("MEH") stream at Houston, Texas which is a representative benchmark for light oil pricing at the U.S. Gulf coast. The MEH benchmark averaged US$40.15/bbl during 2020, representing a premium of US$0.75/bbl relative to WTI, compared to US$61.98/bbl or a premium of US$4.95/bbl for 2019. The decrease in the MEH benchmark premium to WTI in 2020 was a result of elevated inventory levels and lower refinery demand on the U.S. Gulf coast relative to 2019.

Prices for Canadian oil trade at a discount to WTI due to a lack of egress to diversified markets from Western Canada. Canadian light and heavy oil differentials to WTI were wider in early 2020 relative to 2019 as a result of higher Canadian oil production leading into the year. During Q1/2020, the Edmonton par discount to WTI was US$7.92/bbl and the WCS differential was US$20.53/bbl. Canadian oil differentials began to narrow due to production shut-ins in Western Canada during Q2/2020. This resulted in an Edmonton par differential of US$5.60/bbl and a WCS differential of US$12.60/bbl for 2020 which was relatively consistent with US$4.86/bbl and US$12.75/bbl for 2019, respectively.

We compare the price received for our light oil production in Canada to the Edmonton par benchmark oil price which is the representative benchmark for light grades of crude oil in Western Canada. The Edmonton par price averaged $45.34/bbl for 2020 compared to $69.22/bbl for 2019. Edmonton par traded at a discount to WTI of US$5.60/bbl in 2020 which is relatively consistent with US$4.86/bbl for 2019.

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 price for 2020 averaged $35.95/bbl, which represents a differential of US$12.60/bbl to WTI, compared to $58.75/bbl for 2019, which represents a differential of US$12.75/bbl.

Natural Gas

U.S. natural gas prices for 2020 were lower than 2019 as U.S. natural gas inventory levels remained elevated due to lower demand despite falling natural gas production. Canadian natural gas prices improved during 2020 due to low Alberta inventory levels along with improved demand in Western Canada and high utilization of pipeline export capacity during 2020.

Our U.S. natural gas production is priced in reference to the New York Mercantile Exchange ("NYMEX") natural gas index. The NYMEX natural gas benchmark averaged US$2.08/mmbtu in 2020 which is lower than US$2.63/mmbtu in 2019. Record U.S. natural gas production levels leading in to 2020 resulted in an oversupplied North American market and lower natural gas prices in 2020 relative to 2019.

In Canada, we receive natural gas pricing based on the AECO benchmark which continues to trade at a discount to NYMEX as a result of limited market access for Canadian natural gas production. The AECO benchmark averaged $2.24/mcf during 2020 compared to $1.62/mcf during 2019. The AECO benchmark was higher in 2020 relative to 2019 due to lower associated gas production from lower oil production in Western Canada during 2020.

The following tables compare select benchmark prices and our average realized selling prices for the years ended December 31, 2020 and 2019.

	Years Ended December 31		
	2020	2019	Change
Benchmark Averages			
WTI oil (US$/bbl) (1)	**39.40**	57.03	(17.63)
MEH oil (US$/bbl) (2)	**40.15**	61.98	(21.83)
MEH oil differential to WTI (US$/bbl)	**0.75**	4.95	(4.20)
Edmonton par oil ($/bbl) (3)	**45.34**	69.22	(23.88)
Edmonton par oil differential to WTI (US$/bbl)	**(5.60)**	(4.86)	(0.74)
WCS heavy oil ($/bbl) (4)	**35.95**	58.75	(22.80)
WCS heavy oil differential to WTI (US$/bbl)	**(12.60)**	(12.75)	0.15
AECO natural gas price ($/mcf) (5)	**2.24**	1.62	0.62
NYMEX natural gas price (US$/mmbtu) (6)	**2.08**	2.63	(0.55)
CAD/USD average exchange rate	**1.3413**	1.3269	0.0144

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) MEH refers to arithmetic average of the Argus WTI Houston differential weighted index price for the applicable period.
(3) Edmonton par refers to the average posting price for the benchmark MSW crude oil.
(4) WCS refers to the average posting price for the benchmark WCS heavy oil.
(5) AECO refers to the AECO arithmetic average month-ahead index price published by the Canadian Gas Price Reporter ("CGPR").
(6) NYMEX refers to the NYMEX last day average index price as published by the CGPR.

	Years Ended December 31					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
Average Realized Sales Prices						
Light oil and condensate ($/bbl)	**$ 42.35**	**$ 49.84**	**$ 45.98**	$ 65.99	$ 77.46	$ 71.57
Heavy oil ($/bbl) (1)	**24.28**	**—**	**24.28**	44.20	—	44.20
NGL ($/bbl)	**13.47**	**15.57**	**15.22**	16.93	18.74	18.50
Natural gas ($/mcf)	**2.13**	**2.65**	**2.39**	1.71	3.43	2.61
Weighted average ($/boe) (1)	**$ 29.42**	**$ 35.38**	**$ 31.75**	$ 47.15	$ 51.08	$ 48.72

(1) 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 $31.75/boe for 2020 compared to $48.72/boe for 2019. Our realized price in the U.S. was $35.38/boe in 2020 which is $15.70/boe lower than $51.08/boe in 2019. In Canada, our realized price of $29.42/boe for 2020 was $17.73/boe lower than $47.15/boe for 2019. The decrease in our realized price in Canada and the U.S. for 2020 was a result of the decrease in North American benchmark prices relative to 2019.

We compare our light oil realized price in Canada to the Edmonton par benchmark price. Our realized light oil and condensate price in 2020 was $42.35/bbl representing a discount of $2.99/bbl to the Edmonton par benchmark which is relatively consistent with 2019 when our realized price was $65.99/bbl or a discount of $3.23/bbl. The $23.64/boe decrease in our realized light oil pricing in 2020 was driven by the $23.88/boe decline in the Edmonton par benchmark relative to 2019.

We compare the price received for our U.S. light oil and condensate production to the MEH benchmark. Our realized light oil and condensate price averaged $49.84/bbl for 2020 compared to $77.46/bbl for 2019. Expressed in U.S. dollars, our realized light oil and condensate price of US$37.16/bbl for 2020 reflects a US$2.99/bbl discount to the MEH benchmark for 2020 compared to a realized price of US$58.38/bbl and discount of US$3.60/bbl in 2019. A change in marketing contracts during Q3/2019 resulted in improved price realizations for 2020 relative to 2019 which partially offset the impact of a US$21.83/bbl decrease in the MEH benchmark price over the same period.

Our realized heavy oil price, net of blending and other expense averaged $24.28/bbl in 2020 compared to $44.20/bbl in 2019. Our realized heavy oil price for 2020 decreased $19.92/bbl compared to a $22.80/bbl decrease in the WCS benchmark. Our realized heavy oil price did not decrease as much as the WCS benchmark as we shut-in certain properties with lower quality production during 2020 which resulted in improved price realizations during the year.

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. Our realized NGL price was $15.22/bbl in 2020 or 29% of WTI (expressed in Canadian dollars) compared to $18.50/bbl or 24% of WTI (expressed in Canadian dollars) in 2019. Our realized NGL price was higher as a percentage of WTI in 2020 relative to 2019 as the decrease in the underlying products was not as large relative to the decrease in WTI over the same periods.

We compare our realized natural gas price in Canada to the AECO benchmark price. Our realized natural gas price for 2020 was $2.13/mcf compared to $1.71/mcf in 2019. The increase in our realized natural gas price in Canada during 2020 compared to 2019 is consistent with the increase in the AECO natural gas price in 2020. In the U.S., our realized natural gas price was US$1.98/mcf for 2020 compared to US$2.58/mcf in 2019. The decrease in our realized natural gas price in the U.S. during 2020 is consistent with the US$0.55/mmbtu decrease in the NYMEX benchmark in 2020 compared to 2019.

Petroleum and Natural Gas Sales

	Years Ended December 31					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Oil sales						
Light oil and condensate	**$ 296,125**	**$ 327,460**	**$ 623,585**	$ 538,487	$ 600,163	$ 1,138,650
Heavy oil	**236,235**	**—**	**236,235**	500,187	—	500,187
NGL	**6,037**	**34,845**	**40,882**	8,430	60,647	69,077
Total liquids sales	**538,397**	**362,305**	**900,702**	1,047,104	660,810	1,707,914
Natural gas sales	**33,344**	**41,431**	**74,775**	30,620	67,385	98,005
Total petroleum and natural gas sales	**571,741**	**403,736**	**975,477**	1,077,724	728,195	1,805,919
Blending and other expense	**(48,381)**	**—**	**(48,381)**	(68,795)	—	(68,795)
Total sales, net of blending and other expense	**$ 523,360**	**$ 403,736**	**$ 927,096**	$ 1,008,929	$ 728,195	$ 1,737,124

Total sales, net of blending and other expense, of $927.1 million for 2020 decreased $810.0 million from $1,737.1 million for 2019. The decrease in total sales in 2020 is a result of lower realized pricing from the decrease in benchmark pricing along with lower production relative to 2019.

In Canada, total sales, net of blending and other expense, was $523.4 million for 2020 which is a decrease of $485.6 million from $1,008.9 million reported for 2019. Lower pricing resulted in a $315.4 million decrease in total sales, net of blending and other expense and lower production caused a $170.2 million decrease in total sales net of blending and other expense.

In the U.S., petroleum and natural gas sales were $403.7 million for 2020 which is a decrease of $324.5 million from $728.2 million reported for 2019. Lower pricing in 2020 resulted in a $179.2 million decrease in total petroleum and natural gas sales while lower production caused a $145.3 million decrease in total petroleum and natural gas sales relative to 2019.

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, 2020 and 2019.

	Years Ended December 31					
	2020			2019		
($ thousands except for % and per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Royalties	**$ 46,064**	**$ 117,671**	**$ 163,735**	$ 107,467	$ 212,774	$ 320,241
Average royalty rate [(1)]	**8.8 %**	**29.1 %**	**17.7 %**	10.7 %	29.2 %	18.4 %
Royalty rate per boe	**$ 2.59**	**$ 10.31**	**$ 5.61**	$ 5.02	$ 14.93	$ 8.98

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

Royalties for 2020 were $163.7 million or 17.7% of total sales, net of blending and other expense, compared to $320.2 million or 18.4% in 2019. Total royalty expense is lower in 2020 due to lower total sales, net of blending and other expense, relative to 2019. Our average royalty rate of 17.7% for 2020 is slightly lower than 18.4% for 2019 due to a lower royalty rate on our Canadian properties as a result of lower commodity prices.

In Canada, royalties averaged 8.8% of sales for 2020 which was lower than 10.7% for 2019 due to lower benchmark commodity prices which resulted in a lower royalty rate on our Canadian properties. In the U.S., royalties averaged 29.1% of sales for 2020 which is consistent with 29.2% for 2019 as the royalty rate on our U.S. production does not vary with price but can vary across our acreage.

Our average royalty rate of 17.7% for 2020 is consistent with expectations and was slightly below our annual guidance of approximately 18.5% for 2020. We expect our average royalty rate to be 18.0% to 18.5% in 2021.

Operating Expense

	Years Ended December 31					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Operating expense	**$ 247,050**	**$ 84,295**	**$ 331,345**	$ 298,303	$ 99,413	$ 397,716
Operating expense per boe	**$ 13.89**	**$ 7.39**	**$ 11.35**	$ 13.94	$ 6.97	$ 11.16

Operating expense was $331.3 million ($11.35/boe) in 2020 compared to $397.7 million ($11.16/boe) in 2019. The decrease in total operating expense can be attributed to a decrease in production in addition to our cost savings initiatives in 2020. The per unit costs increased slightly to $11.35/boe in 2020 from $11.16/boe in 2019 as cost reductions did not completely offset the impact of fixed costs on lower production volumes.

In Canada, operating expense was $247.1 million ($13.89/boe) for 2020 compared to $298.3 million ($13.94/boe) for 2019. Operating expense in Canada decreased with lower production in 2020 compared to 2019. Despite lower production, per unit operating expense of $13.89/boe for 2020 was consistent with $13.94/boe for 2019 due to our cost savings initiatives in addition to shutting in certain properties with higher operating costs for a portion of 2020.

U.S. operating expense was $84.3 million ($7.39/boe) for 2020 compared to $99.4 million ($6.97/boe) for 2019. Operating expense in the U.S. decreased with lower production in 2020 compared to 2019. Expressed in U.S. dollars, per unit operating expense was US$5.51/boe for 2020 compared to US$5.25/boe for 2019. The slight increase in per unit operating expense in the U.S. was a result of lower production in 2020 relative to 2019 as a portion of our operating expenses are fixed costs.

Operating expense of $11.35/boe for 2020 is consistent with our expectations and was slightly below our annual guidance range of $11.75 - $12.50 per boe as we had higher operating cost production shut-in for a portion of 2020. We expect annual operating expense of $11.50 - $12.25 per boe for 2021.

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, 2020 and 2019.

	Years Ended December 31					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Transportation expense	**$ 28,437**	**$ —**	**$ 28,437**	$ 43,942	$ —	$ 43,942
Transportation expense per boe	**$ 1.60**	**$ —**	**$ 0.97**	$ 2.05	$ —	$ 1.23

Transportation expense was $28.4 million ($0.97/boe) for 2020 compared to $43.9 million ($1.23/boe) for 2019. The decrease in total transportation expense in 2020 relative to 2019 is primarily the result of lower light and heavy oil production in Canada. Optimization of light and heavy oil deliveries in Canada resulted in lower per boe transportation expense for 2020 relative to 2019. Transportation expense of $0.97/boe for 2020 is consistent with expectations and is at the low end of our annual guidance range of $0.95 - $1.05 per boe for 2020. We expect annual transportation expense of $1.00 - $1.10 per boe for 2021.

Blending and Other Expense

Blending and other expense primarily relates to the cost of diluent purchased to reduce the viscosity of our heavy oil transported through pipelines in order to meet pipeline specifications. 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.

Blending and other expense was $48.4 million for 2020 compared to $68.8 million for 2019. The reduction in blending and other expense in 2020 compared to 2019 reflects lower heavy oil sales due to shut-in heavy oil production in addition to a lower per unit cost of blending diluent during 2020.

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, 2020 and 2019.

	Years Ended December 31		
($ thousands)	**2020**	2019	Change
Realized financial derivatives gain (loss)			
Crude oil	**$ 48,495**	$ 72,052	$ (23,557)
Natural gas	**138**	3,577	(3,439)
Interest and financing	**(797)**	(9)	(788)
Total	**$ 47,836**	$ 75,620	$ (27,784)
Unrealized financial derivatives gain (loss)			
Crude oil	**$ (17,696)**	$ (80,602)	$ 62,906
Natural gas	**282**	(1,857)	2,139
Interest and financing	**34**	(358)	392
Equity total return swap	**(1,120)**	—	(1,120)
Total	**$ (18,500)**	$ (82,817)	$ 64,317
Total financial derivatives gain (loss)			
Crude oil	**$ 30,799**	$ (8,550)	$ 39,349
Natural gas	**420**	1,720	(1,300)
Interest and financing	**(763)**	(367)	(396)
Equity total return swap	**(1,120)**	—	(1,120)
Total	**$ 29,336**	$ (7,197)	$ 36,533

We recorded total financial derivatives gains of $29.3 million for 2020. The realized financial derivatives gain for 2020 of $47.8 million was primarily a result of the market prices for crude oil settling at levels below those set in our derivative contracts. The unrealized loss on financial derivatives of $18.5 million for 2020 was primarily due to fluctuations in future commodity prices and the revaluation of contracts in place at December 31, 2020 compared to the value of contracts in place at the start of the year.

Realized gains on crude oil financial derivatives of $48.5 million in 2020 were primarily a result of market prices for WTI settling at levels below the prices set in our contracts outstanding during the year.

The unrealized financial derivatives loss of $18.5 million recorded for 2020 is primarily associated with an increase in forecasted crude oil pricing used in the valuation of WTI contracts entered during the year. The fair value of our financial derivative contracts resulted in a net liability of $21.7 million at December 31, 2020 compared to a net liability of $3.2 million at December 31, 2019.

Baytex had the following commodity financial derivative contracts as at February 24, 2021.

	Period	Volume	Price/Unit [1]	Index
Oil				
Basis swap	Jan 2021 to Jun 2021	2,000 bbl/d	WTI less US$13.75/bbl	WCS
Basis swap	Jan 2021 to Dec 2021	7,000 bbl/d	WTI less US$13.68/bbl	WCS
Basis swap [4]	Apr 2021 to Dec 2021	1,000 bbl/d	WTI less US$11.50/bbl	WCS
Basis swap [4]	Jan 2022 to Dec 2022	6,000 bbl/d	WTI less US$12.76/bbl	WCS
Basis swap	Jan 2021 to Dec 2021	6,000 bbl/d	WTI less US$5.17/bbl	MSW
Basis swap [4]	Mar 2021 to Dec 2021	1,500 bbl/d	WTI less US$4.50/bbl	MSW
Fixed - Sell	Jan 2021 to Dec 2021	4,000 bbl/d	US$45.00/bbl	WTI
3-way option [2]	Jan 2021 to Dec 2021	500 bbl/d	US$35.00/US$45.00/US$49.03	WTI
3-way option [2]	Jan 2021 to Dec 2021	1,500 bbl/d	US$35.00/US$45.00/US$49.10	WTI
3-way option [2]	Jan 2021 to Dec 2021	3,500 bbl/d	US$35.00/US$45.00/US$49.50	WTI
3-way option [2]	Jan 2021 to Dec 2021	10,000 bbl/d	US$35.00/US$45.00/US$55.00	WTI
3-way option [2]	Jan 2021 to Dec 2021	2,000 bbl/d	US$37.00/US$42.50/US$48.00	WTI
3-way option [2][4]	Jan 2022 to Dec 2022	1,500 bbl/d	US$40.00/US$50.00/US$58.10	WTI
Swaption [3]	Jan 2022 to Dec 2022	5,000 bbl/d	US$53.00/bbl	WTI
Swaption [3]	Jan 2022 to Dec 2022	5,000 bbl/d	US$54.00/bbl	WTI
Natural Gas				
Fixed - Sell	Jan 2021 to Jun 2021	3,000 GJ/d	$2.71/GJ	AECO 7A
Fixed - Sell	Jan 2021 to Dec 2021	16,000 GJ/d	$2.36/GJ	AECO 7A
Fixed - Sell	Jan 2021 to Dec 2021	2,500 GJ/d	$2.40/GJ	AECO 5A
Fixed - Sell	Jan 2021 to Dec 2021	12,000 mmbtu/d	US$2.70/mmbtu	NYMEX
3-way option [2]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.25/US$2.75/US$3.06	NYMEX
3-way option [2][4]	Jan 2022 to Dec 2022	2,500 mmbtu/d	US$2.65/US$2.90/US$3.40	NYMEX

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

(2) Producer 3-way option consists of a sold put, a bought put and a sold call. To illustrate, in a US$35.00/US$45.00/US$55.00 contract, Baytex receives WTI plus US$10.00/bbl when WTI is at or below US$35.00/bbl; Baytex receives US$45.00/bbl when WTI is between US$35.00/bbl and US$45.00/bbl; Baytex receives the market price when WTI is between US$45.00/bbl and US$55.00/bbl; and Baytex receives US$55.00/bbl when WTI is above US$55.00/bbl.

(3) For these contracts, the counterparty has the right, if exercised on December 31, 2021, to enter a swap transaction for the remaining term, notional volume and fixed price per unit indicated above.

(4) Contracts entered subsequent to December 31, 2020.

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, 2020 and 2019.

	Years Ended December 31					
	2020			2019		
($ per boe except for volume)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total production (boe/d)	**48,602**	**31,179**	**79,781**	58,625	39,055	97,680
Operating netback:						
Total sales, net of blending and other expense	**$ 29.42**	**$ 35.38**	**$ 31.75**	$ 47.15	$ 51.08	$ 48.72
Less:						
Royalties	**(2.59)**	**(10.31)**	**(5.61)**	(5.02)	(14.93)	(8.98)
Operating expense	**(13.89)**	**(7.39)**	**(11.35)**	(13.94)	(6.97)	(11.16)
Transportation expense	**(1.60)**	**—**	**(0.97)**	(2.05)	—	(1.23)
Operating netback	**$ 11.34**	**$ 17.68**	**$ 13.82**	$ 26.14	$ 29.18	$ 27.35
Realized financial derivatives gain	**—**	**—**	**1.64**	—	—	2.12
Operating netback after financial derivatives	**$ 11.34**	**$ 17.68**	**$ 15.46**	$ 26.14	$ 29.18	$ 29.47

Operating netback after financial derivatives was $15.46/boe for 2020 compared to $29.47/boe for 2019. Operating netback was lower in 2020 relative to 2019 due to the decrease in benchmark pricing which resulted in a $13.60/boe reduction in sales, net of royalties. Operating and transportation expense in Canada of $15.49/boe for 2020 reflects our production optimization and cost savings initiatives which resulted in lower costs relative to $15.99/boe for 2019. Operating expense in the U.S. of $7.39/boe for 2020 was slightly higher relative to $6.97/boe for 2019 as a result of lower production, as a portion of our operating expense in the U.S. are fixed costs.

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

The following table summarizes our G&A expense for the years ended December 31, 2020 and 2019.

	Years Ended December 31		
($ thousands except for per boe)	**2020**	2019	Change
Gross general and administrative expense	**$ 37,217**	$ 51,660	$ (14,443)
Overhead recoveries	**(2,949)**	(6,191)	3,242
General and administrative expense	**$ 34,268**	$ 45,469	$ (11,201)
General and administrative expense per boe	**$ 1.17**	$ 1.28	$ (0.11)

G&A expense was $34.3 million ($1.17/boe) for 2020 compared to $45.5 million ($1.28/boe) for 2019.

G&A expense of $34.3 million for 2020 was $11.2 million lower than $45.5 million for 2019 due to reduced staffing levels combined with our cost saving initiatives, which included salary reductions and reduced consulting costs. G&A expense for 2020 includes a benefit of $3.9 million related to the Canada Emergency Wage Subsidy ("CEWS") program implemented by the federal government in response to the COVID-19 pandemic. Despite lower production in 2020 relative to 2019, G&A expense of $1.17/boe for 2020 was lower than $1.28/boe for 2019 as a result of our cost saving initiatives and the benefit of the CEWS.

G&A expense of $34.3 million ($1.17/boe) for 2020 was below our annual guidance of $38 million ($1.30/boe) due to our cost savings programs. We expect annual G&A expense of $42.0 million ($1.53/boe) for 2021 as we do not expect to benefit from the CEWS.

Financing and Interest Expense

Financing and interest expense includes interest on our credit facilities, long-term notes and lease obligations as well as non-cash financing costs which include the accretion on our debt issue costs and asset retirement obligations. Financing and interest expense varies depending on debt levels outstanding during the period, 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.

The following table summarizes our financing and interest expense for the years ended December 31, 2020 and 2019.

	Years Ended December 31					
($ thousands except for per boe)		**2020**		2019		Change
Interest on credit facilities	**$**	**15,256**	$	20,376	$	(5,120)
Interest on long-term notes		**90,830**		86,431		4,399
Interest on lease obligations		**448**		610		(162)
Cash interest	**$**	**106,534**	$	107,417	$	(883)
Accretion of debt issue costs		**6,617**		4,735		1,882
Accretion of asset retirement obligations		**8,978**		13,713		(4,735)
Early redemption expense	**$**	**3,312**	$	—		3,312
Financing and interest expense	**$**	**125,441**	$	125,865	$	(424)
Cash interest per boe	**$**	**3.65**	$	3.01	$	0.64
Financing and interest expense per boe	**$**	**4.30**	$	3.53	$	0.77

Financing and interest expense was $125.4 million ($4.30/boe) in 2020 compared to $125.9 million ($3.53/boe) in 2019.

Cash interest of $106.5 million ($3.65/boe) in 2020 is slightly lower than $107.4 million ($3.01/boe) in 2019. Interest on our credit facilities was lower in 2020 primarily due to a lower weighted average borrowing rate on amounts outstanding relative to 2019. The weighted average interest rate on our credit facilities was 2.0% in 2020 compared to 4.0% in 2019. Interest on our long-term notes was higher in 2020 due to the issuance of the US$500 million principal amount of 8.75% senior unsecured notes. Proceeds from the issuance of the US$500 million principal amount of 8.75% senior unsecured notes were used to redeem the US$400 million principal amount of 5.125% senior unsecured notes on February 20, 2020 along with the $300 million principal amount of 6.625% senior unsecured notes on March 5, 2020.

Financing and interest expense for 2020 also includes the accelerated amortization of debt issue costs and $3.3 million of early redemption expense associated with the $300 million principal amount of 6.625% senior unsecured notes which were redeemed at 101.104% of the principal amount on March 5, 2020. Accretion of asset retirement obligations of $9.0 million for 2020 was lower than $13.7 million for 2019 due to a lower risk free discount rate for 2020 relative to 2019.

Cash interest of $106.5 million ($3.65/boe) for 2020 was below our annual guidance of $112.0 million ($3.84/boe). We expect annual cash interest to be $105.0 million ($3.84/boe) for 2021.

Exploration and Evaluation Expense

Exploration and evaluation ("E&E") expense is related to the expiry of leases and the de-recognition of costs for exploration programs that have not demonstrated commercial viability and technical feasibility. E&E expense will vary depending on the timing of expiring leases, the accumulated costs of the expiring leases and the economic facts and circumstances related to the Company's exploration programs. E&E expense was $14.0 million for 2020 which is higher than $11.8 million for 2019 due to a higher amount of acreage expiring in 2020 relative to 2019.

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, 2020 and 2019.

	Years Ended December 31		
($ thousands except for per boe)	**2020**	2019	Change
Depletion	**$ 478,859**	$ 725,267	$ (246,408)
Depreciation	**7,521**	6,419	1,102
Depletion and depreciation	**$ 486,380**	$ 731,686	$ (245,306)
Depletion and depreciation per boe	**$ 16.66**	$ 20.52	$ (3.86)

Depletion and depreciation expense was $486.4 million ($16.66/boe) for 2020 compared to $731.7 million ($20.52/boe) reported for 2019. Total depletion and depreciation expense was lower in 2020 relative to 2019 due to lower production in 2020 combined with a reduced depletable base resulting from the $2.6 billion of impairment recorded in Q1/2020.

Impairment

At March 31, 2020, we identified indicators of impairment due to the sharp decline in forecasted commodity prices. We performed impairment tests on the E&E assets and oil and gas properties for our six CGUs. We recorded total impairments of $2.7 billion in Q1/2020 as the carrying value of the E&E assets and oil and gas properties exceeded the estimated recoverable amounts of the CGUs. The total impairment recorded at Q1/2020 includes $2.6 billion related to oil and gas properties and $0.1 billion related to E&E assets.

At December 31, 2020, with updated development plans, including capital efficiencies and reduced well costs, reflected in our reserves along with changes in commodity prices, we estimated the recoverable amount for E&E assets and oil and gas properties in each of our six CGUs. We recorded an impairment reversal of $356.1 million at December 31, 2020 as the estimated recoverable amount of the Viking and Eagle Ford CGUs exceeded their carrying value. The total impairment reversal recorded at Q4/2020 includes $341.3 million related to oil and gas properties and $14.8 million related to E&E assets.

At March 31, 2020 the recoverable amount of the Company's CGUs were calculated using the following benchmark reference prices for the years 2020 to 2029 adjusted for commodity differentials specific to the Company. The prices and costs subsequent to 2029 have been adjusted for inflation at an annual rate of 2.0%.

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
WTI crude oil (US$/bbl)	29.17	40.45	49.17	53.28	55.66	56.87	58.01	59.17	60.35	61.56
WCS heavy oil (CA$/bbl)	19.21	34.65	46.34	51.25	54.28	55.72	56.96	58.22	59.51	60.82
LLS crude oil (US$/bbl)	32.17	43.80	52.55	56.68	59.10	60.35	61.52	62.72	63.94	65.19
Edmonton par oil (CA$/bbl)	29.22	46.85	59.27	65.02	68.43	69.81	71.24	72.70	74.19	75.71
Henry Hub gas (US$/mmbtu)	2.10	2.58	2.79	2.86	2.93	3.00	3.07	3.13	3.19	3.25
AECO gas (CA$/mmbtu)	1.74	2.20	2.38	2.45	2.53	2.60	2.66	2.72	2.79	2.85
Exchange rate (CAD/USD)	1.41	1.37	1.34	1.34	1.34	1.33	1.33	1.33	1.33	1.33

The following table summarizes the recoverable amount and impairment at March 31, 2020 and demonstrates the sensitivity of the estimated recoverable amount of the Company's CGUs comprising oil and gas properties to reasonably possible changes in key assumptions inherent in the estimate.

	Recoverable amount	Impairment	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU	$ 37,444	$ 41,000	$ 3,000	$ 3,500	$ 8,500
Peace River CGU	109,631	345,000	9,500	53,500	3,000
Lloydminster CGU	227,967	470,000	25,000	69,500	—
Duvernay CGU	61,197	5,000	5,500	9,500	1,500
Viking CGU	962,134	915,000	57,000	123,000	4,000
Eagle Ford CGU	1,576,423	812,488	120,750	141,500	32,000
	$ 2,974,796	$ 2,588,488	$ 220,750	$ 400,500	$ 49,000

At December 31, 2020, the recoverable amount of the Company's CGUs were calculated using the following benchmark reference prices for the years 2021 to 2030 adjusted for commodity differentials specific to the Company. The prices and costs subsequent to 2030 have been adjusted for inflation at an annual rate of 2.0%.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
WTI crude oil (US$/bbl)	47.17	50.17	53.17	54.97	56.07	57.19	58.34	59.50	60.69	61.91
WCS heavy oil (CA$/bbl)	44.63	48.18	52.10	54.10	55.19	56.29	57.42	58.57	59.74	60.93
LLS crude oil (US$/bbl)	49.50	52.85	55.87	57.69	58.82	59.97	61.15	62.34	63.56	64.83
Edmonton par oil (CA$/bbl)	55.76	59.89	63.48	65.76	67.13	68.53	69.95	71.40	72.88	74.34
Henry Hub gas (US$/mmbtu)	2.83	2.87	2.90	2.96	3.02	3.08	3.14	3.20	3.26	3.33
AECO gas (CA$/mmbtu)	2.78	2.70	2.61	2.65	2.70	2.76	2.81	2.87	2.92	2.98
Exchange rate (CAD/USD)	1.30	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31	1.31

The following table summarizes the recoverable amount and impairment reversal at December 31, 2020 and demonstrates the sensitivity of the estimated recoverable amount of the Company's CGUs comprising oil and gas properties to reasonably possible changes in key assumptions inherent in the estimate.

	Recoverable amount	Impairment reversal	Change in discount rate of 1%	Change in oil price of $2.50/bbl	Change in gas price of $0.25/mcf
Conventional CGU	$ 54,265	$ —	$ 1,000	$ 3,000	$ 9,000
Peace River CGU	104,225	—	1,000	49,500	3,000
Lloydminster CGU	212,979	—	7,000	57,500	500
Duvernay CGU	70,491	—	5,500	12,000	1,500
Viking CGU	1,026,026	116,000	34,500	106,500	5,000
Eagle Ford CGU	1,609,562	225,326	91,600	157,500	38,400
	$ 3,077,548	$ 341,326	$ 140,600	$ 386,000	$ 57,400

Share-Based Compensation Expense

Share-based compensation ("SBC") expense includes expense associated with our Share Award Incentive Plan and our Incentive Award Plan. SBC expense associated with our Share Award Incentive Plan is recognized in net income or loss over the vesting period of the awards with a corresponding increase in contributed surplus. SBC expense associated with our Incentive Award Plan is recognized in net income or loss over the vesting period of the awards with a corresponding financial liability and includes gains or losses on equity total return swaps used to fix the aggregate cost of new grants made under the plan. SBC expense varies with the quantity of unvested share awards outstanding and the grant date fair value assigned to the share awards.

We recorded SBC expense of $9.5 million for 2020 which is lower than $15.9 million reported for 2019. SBC expense is lower in 2020 as the total value of awards granted in 2020 was lower than prior years. The total expense for 2020 is comprised of non-cash compensation expense of $7.2 million related to the Share Award Incentive Plan and cash compensation expense of $2.3 million related to the Incentive Award Plan.

Foreign Exchange

Unrealized foreign exchange gains and losses are primarily a result of changes in the reported amount of our U.S. dollar denominated long-term notes and our U.S. dollar denominated intercompany notes. The long-term notes and intercompany notes are translated to Canadian dollars on the balance sheet date using the closing CAD/USD exchange rate resulting in unrealized gains and losses. Realized foreign exchange gains and losses are due to day-to-day U.S. dollar denominated transactions occurring in our Canadian functional currency entities.

	Years Ended December 31		
($ thousands except for exchange rates)	**2020**	2019	Change
Unrealized foreign exchange loss - intercompany notes [(1)]	**$ 31,617**	$ —	$ 31,617
Unrealized foreign exchange gain - long-term notes	**(22,385)**	(62,753)	40,368
Realized foreign exchange (gain) loss	**(544)**	966	(1,510)
Foreign exchange loss (gain)	**$ 8,688**	$ (61,787)	$ 70,475
CAD/USD exchange rates:			
At beginning of period	**1.2965**	1.3646	
At end of period	**1.2755**	1.2965	

(1) During 2020, a series of intercompany notes totaling US$751.0 million were issued from a Canadian subsidiary to a U.S. subsidiary. These notes are eliminated upon consolidation within the Statement of Financial Position and are revalued at the relevant foreign exchange rate at each period end. Foreign exchange gains or losses incurred within the Canadian subsidiary are recognized in unrealized foreign exchange gain or loss whereas those within the U.S. subsidiary are recognized in other comprehensive income.

We recorded an unrealized foreign exchange gain on our long-term notes of $22.4 million due to the strengthening of the Canadian dollar relative to the U.S. dollar at December 31, 2020 compared to December 31, 2019. This compares to an unrealized foreign exchange gain of $62.8 million in 2019 due to the strengthening of the Canadian dollar relative to the U.S. dollar at December 31, 2019 compared to December 31, 2018.

We recorded an unrealized foreign exchange loss of $31.6 million on our intercompany notes issued by our Canadian subsidiary due to the strengthening of the Canadian dollar relative to the U.S. dollar at December 31, 2020 from when the intercompany notes were issued in September 2020 when the CAD/USD rate was 1.3199.

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 gain of $0.5 million for 2020 compared to a loss of $1.0 million for 2019.

Income Taxes

	Years Ended December 31		
($ thousands)	**2020**	2019	Change
Current income tax expense	**$ 574**	$ 2,093	$ (1,519)
Deferred income tax recovery	**(160,967)**	(68,555)	(92,412)
Total income tax recovery	**$ (160,393)**	$ (66,462)	$ (93,931)

Current income expense was $0.6 million for 2020 compared to $2.1 million recorded in 2019. Current income tax is lower in 2020 due to lower state tax owed on our U.S. operations.

We recorded a deferred income tax recovery of $161.0 million for 2020 compared to $68.6 million for 2019. We recorded a higher deferred income tax recovery in 2020 primarily due to lower net income before tax as a result of the impairments recorded in 2020. The recovery for 2020 was reduced by a change in valuation allowance of $444.1 million which was recognized against certain deferred tax assets due to uncertainty of future cash flows.

As disclosed in the 2019 annual financial statements, certain indirect subsidiaries received reassessments from the Canada Revenue Agency (the "CRA") that deny $591.0 million of non-capital loss deductions relevant to the calculation of income taxes for the years 2011 through 2015. In September 2016, we filed notices of objection with the CRA appealing each reassessment received. There has been no change in the status of these reassessments since an Appeals Officer was assigned to our file in July 2018. We remain confident that our original tax filings are correct and intend to defend these tax filings through the appeals process.

Canadian Tax Pools *($ thousands)*	**December 31, 2020**	December 31, 2019
Canadian oil and natural gas property expenditures	**$ 449,670**	$ 492,616
Canadian development expenditures	**557,554**	696,298
Canadian exploration expenditures	**10,907**	9,726
Undepreciated capital costs	**347,297**	433,768
Non-capital losses	**1,015,152**	705,298
Financing costs and other	**14,780**	4,424
Total Canadian tax pools	**$ 2,395,360**	$ 2,342,130

U.S. Tax Pools *($ thousands)*		
Depletion	**$ 147,160**	$ 156,184
Intangible drilling costs	**5,521**	18,618
Tangibles	**39,028**	64,496
Non-capital losses	**1,150,068**	1,009,260
Other	**192,495**	452,710
Total U.S. tax pools	**$ 1,534,272**	$ 1,701,268

Net Income (Loss) and Adjusted Funds Flow

The components of adjusted funds flow and net income or loss for the years ended December 31, 2020 and 2019 are set forth in the following table.

	Years Ended December 31		
($ thousands)	**2020**	2019	Change
Petroleum and natural gas sales	**$ 975,477**	$ 1,805,919	$ (830,442)
Royalties	**(163,735)**	(320,241)	156,506
Revenue, net of royalties	**811,742**	1,485,678	(673,936)
Expenses			
Operating	**(331,345)**	(397,716)	66,371
Transportation	**(28,437)**	(43,942)	15,505
Blending and other	**(48,381)**	(68,795)	20,414
Operating netback	**$ 403,579**	$ 975,225	$ (571,646)
General and administrative	**(34,268)**	(45,469)	11,201
Cash financing and interest	**(106,534)**	(107,417)	883
Realized financial derivatives gain	**47,836**	75,620	(27,784)
Realized foreign exchange gain (loss)	**544**	(966)	1,510
Other income	**3,176**	7,526	(4,350)
Current income tax recovery	**(574)**	(2,093)	1,519
Share-based compensation	**(2,253)**	—	(2,253)
Adjusted funds flow	**$ 311,506**	$ 902,426	$ (590,920)
Exploration and evaluation	**(14,011)**	(11,764)	(2,247)
Depletion and depreciation	**(486,380)**	(731,686)	245,306
Non-cash share-based compensation	**(7,216)**	(15,894)	8,678
Non-cash financing and accretion	**(18,907)**	(18,448)	(459)
Non-cash other income	**2,128**	—	2,128
Unrealized financial derivatives loss	**(18,500)**	(82,817)	64,317
Unrealized foreign exchange (loss) gain	**(9,232)**	62,753	(71,985)
Gain on dispositions	**901**	2,238	(1,337)
Impairment	**(2,360,220)**	(187,822)	(2,172,398)
Deferred income tax recovery	**160,967**	68,555	92,412
Net loss	**$ (2,438,964)**	$ (12,459)	$ (2,426,505)

We generated adjusted funds flow of $311.5 million for 2020 compared to $902.4 million for 2019. The decrease in adjusted funds flow for 2020 is primarily due to the decline in commodity benchmark prices and lower production, which resulted in a $653.5 million decrease in revenue, net of royalties and blending and other expense. This decrease in adjusted funds flow in 2020 relative to 2019 was mitigated by our costs saving initiatives which resulted in a $93.1 million reduction in operating, transportation, and general and administrative expenses.

We reported a net loss of $2.4 billion for 2020 compared to $12.5 million for 2019. The net loss for 2020 was primarily a result of impairments of $2.4 billion along with lower commodity prices and production which resulted in a $590.9 million decrease in adjusted funds flow. This was partially offset by lower depletion and depreciation in 2020 compared to 2019.

Other Comprehensive Income (Loss)

Other comprehensive income or loss is comprised of the foreign currency translation adjustment on U.S. net assets which includes a series of intercompany debt instruments outstanding between our Canadian and U.S. subsidiaries. Foreign exchange gains or losses on the debt owing from the U.S. subsidiary is recorded in other comprehensive income and the offsetting foreign exchange gain or loss on debt owed to the Canadian subsidiary is included in profit and loss for the period.

The $62.8 million foreign currency translation gain for 2020 is a result of the U.S. dollar strengthening during Q1/2020 as we had a higher amount of U.S. net assets prior to impairment recorded at March 31, 2020. U.S. net assets were lower as a result of the impairment as the Canadian dollar strengthened relative to the U.S. dollar over the remainder of 2020. The foreign currency translation adjustment for 2020 also includes a gain of $31.6 million related to the remeasurement of intercompany notes in our U.S. subsidiary. The CAD/USD exchange rate was 1.2755 at December 31, 2020 compared to 1.4120 at March 31, 2020 and 1.2965 at December 31, 2019.

Capital Expenditures

Capital expenditures for the years ended December 31, 2020 and 2019 are summarized as follows.

	Years Ended December 31					
	2020			2019		
($ thousands)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Drilling, completion and equipping	**$ 143,013**	**$ 104,599**	**$ 247,612**	$ 319,417	$ 166,094	$ 485,511
Facilities	**26,043**	**21**	**26,064**	41,141	10,220	51,361
Land, seismic and other	**5,896**	**768**	**6,664**	13,805	1,614	15,419
Total exploration and development	**$ 174,952**	**$ 105,388**	**$ 280,340**	$ 374,363	$ 177,928	$ 552,291
Acquisitions, net of proceeds from divestitures	**$ (182)**	**$ —**	**$ (182)**	$ 2,180	$ —	$ 2,180

Exploration and development expenditures were $280.3 million for 2020 compared to $552.3 million for 2019. Expenditures were lower in 2020 compared to 2019 as we adjusted our development programs in the U.S. and Canada in response to the volatility in crude oil prices throughout 2020. We were active on our properties early in 2020 as crude oil prices were stable and supported active development. After the significant decline in crude oil prices in March 2020, we moderated the pace of development in the U.S. and suspended our operated capital activity in Canada. We re-started development activity on our light oil properties as crude oil prices increased during Q4/2020 and the outlook for global demand improved.

In Canada, we invested $175.0 million on exploration and development activities in 2020 which is $199.4 million lower than $374.4 million in 2019. Exploration and development activity in 2020 includes costs associated with drilling 104 (101.2 net) light oil wells, 33 (33.0 net) heavy oil wells, 2 (2.0 net) conventional natural gas wells, 6 (6.0 net) stratigraphic exploration wells and investing $26.0 million on facilities. Exploration and development expenditures of $374.4 million for 2019 included costs associated with drilling 279 (247.8 net) light oil wells, 42 (42.0 net) heavy oil wells, 4 (4.0 net) stratigraphic exploration wells, along with $41.1 million of associated facility expenditures. Total exploration and development costs were lower in 2020 relative to 2019 as we suspended development operations following the sharp decline in crude oil pricing in March 2020.

Total U.S. exploration and development expenditures were $105.4 million for 2020 which is $72.5 million lower than $177.9 million for 2019. Exploration and development expenditures of $105.4 million for 2020 included costs associated with the drilling of 65 (16.3 net) wells along with completing 62 (14.1 net) wells that were brought on production. Development expenditures were lower in 2020 due to lower drilling and completions activity relative to 2019 when we spent $177.9 million and drilled 96 (20.2 net) wells and brought 109 (25.1 net) wells on production.

We completed minor acquisition and disposition transactions in 2020 for net proceeds of $0.2 million compared to net consideration of $2.2 million in 2019.

Total exploration and development expenditures of $280.3 million for 2020 approximated the mid-point of our annual guidance range of $260 - $290 million. We expect annual exploration and development expenditures of $225 - $275 million for 2021.

CAPITAL RESOURCES AND LIQUIDITY

We took action to improve our capital structure and financial liquidity during 2020. On February 5, 2020, we issued US$500 million of senior unsecured notes bearing interest at 8.75% which mature on April 1, 2027. Proceeds from the issuance were used in conjunction with availability on our credit facilities to complete the early redemption of the US$400 million principal amount of 5.125% senior unsecured notes due June 1, 2021 and the $300 million principal amount of 6.625% senior unsecured notes due July 19, 2022. We also negotiated an extension to the maturity of our credit facilities from April 2, 2021 to April 2, 2024. As a result of these actions we do not have any debt maturities until 2024 and we had $367.2 million of undrawn capacity on our credit facilities at December 31, 2020.

Our objective for capital management involves maintaining a flexible capital structure and sufficient sources of liquidity to execute our capital programs, while meeting our short and long-term commitments. We strive to actively manage our capital structure in response to changes in economic conditions. At December 31, 2020, our capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables and the credit facilities.

During 2020 we took additional action to protect our financial liquidity in response to lower oil prices and the global economic instability related to the COVID-19 pandemic. Our 2020 exploration and development expenditures were reduced by moderating the pace of activity in the U.S. and suspending drilling and completion operations in Canada. Certain high cost, low margin, production was shut-in for a portion of 2020 when netbacks were challenged by low commodity prices. Our cost savings initiatives also resulted in lower operating expenses and general and administrative costs during 2020. We have also taken advantage of all government assistance programs available to our industry. As a result of these actions, we were able to maintain our liquidity and generate free cash flow of $18.1 million for 2020 during a period of extremely volatile commodity prices.

The capital-intensive nature of our operations requires us to maintain adequate sources of liquidity to fund ongoing capital programs. 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 fund our 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 or repurchase equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

At December 31, 2020, net debt of $1.85 billion was $24.2 million lower than $1.87 billion at December 31, 2019. Free cash flow of $18.1 million generated in 2020 was directed towards debt repayment and reduced net debt at December 31, 2020. The decrease in net debt was also the result of a $22.4 million decrease in the reported amount of our U.S. dollar denominated net debt due to the strengthening of the Canadian dollar at December 31, 2020 relative to December 31, 2019. These decreases were partially offset by transaction and financing costs of $17.6 million related to the refinancing transactions in Q1/2020.

We monitor our capital structure and liquidity requirements using a net debt to adjusted funds flow ratio calculated on a twelve-month trailing basis. At December 31, 2020, our net debt to adjusted funds flow ratio was 5.9 compared to a ratio of 2.1 as at December 31, 2019. The increase in the net debt to adjusted funds flow ratio relative to December 31, 2019 is attributed to lower adjusted funds flow due to lower commodity pricing during 2020.

Credit Facilities

At December 31, 2020, the principal amount of credit facilities and letters of credit outstanding was $666.2 million and we had approximately $367.2 million of undrawn capacity under our credit facilities that total approximately $1,033.4 million. Our credit facilities include US$575 million of revolving credit facilities and a $300 million non-revolving term loan (collectively, the "Credit Facilities").

On March 3, 2020, we amended our Credit Facilities to extend maturity from April 2, 2021 to April 2, 2024. These facilities will automatically be extended to June 4, 2024 providing we have either refinanced, or have the ability to repay, the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.

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 which could be extended upon our request. Advances (including letters of credit) under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank’s prime lending rate, bankers’ acceptance discount rates or London Interbank Offered Rates ("LIBOR"), plus applicable margins.

The LIBOR benchmark will no longer be published after December 31, 2021. We expect the LIBOR benchmark to be replaced with an alternative that will apply to our U.S. dollar borrowing at our option. We do not expect this change to have a material impact to Baytex as U.S. dollar borrowings under the credit facilities can also bear interest at the U.S. base loan rate.

The agreements and associated amending agreements relating to the Credit Facilities are accessible on the SEDAR website at www.sedar.com.

The weighted average interest rate on the Credit Facilities was 2.0% for 2020 as compared to 4.0% for 2019.

Financial Covenants

At December 31, 2020, we were in compliance with all of the covenants contained in our Credit Facilities and we expect to remain in compliance with the financial covenants applicable to our credit facilities at current forward commodity prices. A decrease or a sustained period of low commodity prices may result in non-compliance with our financial covenants and reduced liquidity on our existing credit facilities. Non-compliance with the financial covenants in our credit facilities could result in our debt becoming due and payable on demand.

The following table summarizes the financial covenants applicable to the Credit Facilities and our compliance therewith at December 31, 2020.

Covenant Description	**Position as at December 31, 2020**	**Covenant**
Senior Secured Debt (1) to Bank EBITDA (2) (Maximum Ratio)	**1.6:1.0**	3.5:1.0
Interest Coverage (3) (Minimum Ratio)	**3.9:1.0**	2.0:1.0

(1) "Senior Secured Debt" is defined as the principal amount of the credit facilities and other secured obligations identified in the credit agreement. As at December 31, 2020, the Company's Senior Secured Debt totaled $666.2 million which includes $651.2 million of principal amounts outstanding and $15.0 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, income tax, non-recurring losses, certain specific unrealized and non-cash transactions (including depletion, depreciation, exploration and evaluation expenses, impairment, deferred income tax expense and recovery, 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, 2020 was $414.9 million.

(3) "Interest coverage" is computed as the ratio of Bank EBITDA to financing and interest expenses, excluding accretion of debt issue costs and asset retirement obligations, and is calculated on a trailing twelve-month basis. Financing and interest expenses, excluding accretion of debt issue costs and asset retirement obligations, for the twelve months ended December 31, 2020 were $106.1 million.

Long-Term Notes

We have two series of long-term notes outstanding that total $1.15 billion as at December 31, 2020. The long-term notes do not contain any financial maintenance covenants but contain a debt incurrence covenant that restricts our ability to raise additional debt beyond our existing Credit Facilities and long-term notes.

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"), which were redeemed February 20, 2020, and US$400 million of 5.625% notes due June 1, 2024 (the "5.625% Notes"), which remain outstanding. The 5.625% Notes pay interest semi-annually with the principal amount repayable at maturity. As of June 1, 2019, the 5.625% Notes are redeemable at our option, in whole or in part, at specified redemption prices and will be redeemable at par from June 1, 2022 to maturity.

On February 5, 2020, we issued US$500 million aggregate principal amount of senior unsecured notes due April 1, 2027 bearing interest at a rate of 8.75% per annum payable semi-annually (the "8.75% Senior Notes)". The 8.75% Senior Notes are redeemable at our option, in whole or in part, at specified redemption prices after April 1, 2023 and will be redeemable at par from April 1, 2026 to maturity. Transaction costs of $12.5 million were incurred in conjunction with the issuance which resulted in net proceeds of $652.2 million.

On February 20, 2020, we used a portion of the net proceeds from the issuance of the 8.75% Senior Notes to complete the early redemption of the US$400 million principal amount of the 5.125% senior unsecured notes due June 1, 2021 at par plus accrued interest. The payment at redemption was $530.4 million.

On March 5, 2020, we completed the early redemption of the $300 million principal amount of the 6.625% senior unsecured notes due July 19, 2022 at 101.104% of the principal amount plus accrued interest. The payment at redemption includes principal of $300.0 million plus early redemption expense of $3.3 million.

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, 2020, we issued 2.9 million common shares pursuant to our share-based compensation program. As at February 24, 2021, we had 561.2 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, 2020 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	**$ 155,955**	$ 155,955	$ —	$ —	$ —
Credit facilities (1) (2)	**651,173**	—	—	651,173	—
Long-term notes (2)	**1,147,950**	—	—	510,200	637,750
Interest on long-term notes (3)	**446,854**	84,502	169,004	123,479	69,869
Lease agreements (2)	**11,850**	4,504	4,302	3,044	—
Processing agreements	**6,361**	836	1,320	474	3,731
Transportation agreements	**98,406**	16,698	40,351	24,903	16,454
Total	**$ 2,518,549**	$ 262,495	$ 214,977	$ 1,313,273	$ 727,804

(1) The credit facilities mature on April 2, 2024. Maturity will automatically be extended to June 4, 2024 providing Baytex has either refinanced, or has the ability to repay, the outstanding 2024 long-term notes with existing credit capacity as of April 1, 2024.
(2) Principal amount of instruments.
(3) Excludes interest on our credit facilities as interest payments fluctuate based on a floating rate of interest and changes in the outstanding balances.

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 OPERATING AND FINANCIAL RESULTS

	Three Months Ended December 31					
	2020			2019		
($ thousands except for per boe)	**Canada**	**U.S.**	**Total**	Canada	U.S.	Total
Total daily production						
Light oil and condensate (bbl/d)	**15,212**	**14,356**	**29,568**	21,531	22,375	43,906
Heavy oil (bbl/d)	**21,725**	**—**	**21,725**	27,050	—	27,050
NGL (bbl/d)	**1,364**	**5,131**	**6,495**	1,170	7,529	8,699
Total liquids (bbl/d)	**38,301**	**19,487**	**57,788**	49,751	29,904	79,655
Natural gas (mcf/d)	**42,117**	**33,999**	**76,116**	48,260	51,975	100,235
Total production (boe/d)	**45,321**	**25,154**	**70,475**	57,794	38,566	96,360
Operating netback ($/boe)						
Light oil and condensate ($/bbl)	**$ 47.43**	**$ 52.73**	**$ 50.00**	$ 65.31	$ 76.46	$ 71.00
Heavy oil ($/bbl)	**27.87**	**—**	**27.87**	40.32	—	40.32
NGL ($/bbl)	**16.57**	**19.18**	**18.63**	16.22	18.75	18.41
Natural gas ($/mcf)	**2.50**	**3.26**	**2.84**	2.39	3.20	2.81
Total sales, net of blending and other per boe	**32.10**	**38.41**	**34.35**	45.52	52.33	48.25
Royalties per boe	**(2.90)**	**(11.11)**	**(5.83)**	(4.73)	(14.69)	(8.72)
Operating expense per boe	**(14.73)**	**(7.92)**	**(12.30)**	(14.41)	(6.47)	(11.23)
Transportation expense per boe	**(1.60)**	**—**	**(1.03)**	(1.66)	—	(1.00)
Operating netback per boe	**$ 12.87**	**$ 19.38**	**$ 15.19**	$ 24.72	$ 31.17	$ 27.30
Financial						
Petroleum and natural gas sales	**$ 144,741**	**$ 88,895**	**$ 233,636**	$ 260,217	$ 185,678	$ 445,895
Royalties	**(12,092)**	**(25,715)**	**(37,807)**	(25,154)	(52,128)	(77,282)
Revenue, net of royalties	**132,649**	**63,180**	**195,829**	235,063	133,550	368,613
Operating	**(61,409)**	**(18,339)**	**(79,748)**	(76,623)	(22,950)	(99,573)
Transportation	**(6,692)**	**—**	**(6,692)**	(8,840)	—	(8,840)
Blending and other	**(10,891)**	**—**	**(10,891)**	(18,167)	—	(18,167)
Operating netback	**$ 53,657**	**$ 44,841**	**$ 98,498**	$ 131,433	$ 110,600	$ 242,033
General and administrative	**—**	**—**	**(9,314)**	—	—	(9,893)
Cash interest	**—**	**—**	**(25,194)**	—	—	(24,389)
Realized financial derivatives gain	**—**	**—**	**17,105**	—	—	22,956
Other	**—**	**306**	**1,081**	—	—	1,440
Adjusted funds flow	**$ 53,657**	**$ 45,147**	**$ 82,176**	$ 131,433	$ 110,600	$ 232,147
Net income (loss)	**$ 112,954**	**$ 144,200**	**$ 221,160**	$ (134,348)	$ 44,937	$ (117,772)
Exploration and development expenditures	**$ 45,030**	**$ 32,779**	**$ 77,809**	$ 104,460	$ 48,657	$ 153,117
Acquisitions, net of proceeds from divestitures	**$ (33)**	**$ —**	**$ (33)**	$ 563	$ —	$ 563
Net debt			**$1,847,601**			$1,871,791

	Three Months Ended December 31		
	2020	2019	Change
Benchmark Averages			
WTI oil (US$/bbl) (1)	**42.66**	56.96	(14.30)
MEH oil (US$/bbl) (2)	**43.05**	60.04	(16.99)
MEH oil differential to WTI (US$/bbl)	**0.39**	3.08	(2.69)
Edmonton par oil ($/bbl)	**50.24**	68.10	(17.86)
Edmonton par oil differential to WTI (US$/bbl)	**(4.11)**	(5.37)	1.26
WCS heavy oil ($/bbl) (3)	**43.46**	54.29	(10.83)
WCS heavy oil differential to WTI (US$/bbl)	**(9.31)**	(15.83)	6.52
AECO natural gas price ($/mcf) (4)	**2.77**	2.34	0.43
NYMEX natural gas price (US$/mmbtu) (5)	**2.66**	2.50	0.16
CAD/USD average exchange rate	**1.3031**	1.3201	(0.0170)

(1) WTI refers to the arithmetic average of NYMEX prompt month WTI for the applicable period.
(2) MEH refers to arithmetic average of the Argus WTI Houston differential weighted index price for the applicable period.
(3) WCS refers to the average posting price for the benchmark WCS heavy 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 Q4/2020 reflect additional development activity after we limited exploration and development expenditures for two quarters in response to the challenging market conditions caused by COVID-19. We invested $77.8 million on exploration and development expenditures in Q4/2020 which were focused on our light oil assets in the U.S. and in Canada. Adjusted funds flow was $82.2 million for Q4/2020 and production of 70,475 boe/d was in line with expectations after two quarters of limited development spending.

In Canada, production averaged 45,321 boe/d in Q4/2020 which was 12,473 boe/d lower than 57,794 boe/d reported for Q4/2019. The decrease in production reflects lower exploration and development activity throughout 2020 relative to 2019. Our weighted average realized price of $32.10/boe for Q4/2020 was $13.42/boe lower than $45.52/boe for Q4/2019 due to a decrease in benchmark prices in Q4/2020 relative to Q4/2019. In Q4/2020, the Edmonton Par benchmark was $50.24/bbl and the WCS heavy oil price was $43.46/bbl compared to $68.10/bbl and $54.29/bbl for the same period of 2019, respectively. As a result of lower production and benchmark pricing, we generated operating netback of $53.7 million ($12.87/boe) for Q4/2020 which was $77.8 million ($11.85/boe) lower than $131.4 million ($24.72/boe) reported for Q4/2019. Exploration and development expenditures of $45.0 million in Q4/2020 includes drilling and completion costs associated with 32 (32.0 net) wells compared to 73 (70.7 net) wells in Q4/2019 when we spent $104.5 million.

In the U.S., production averaged 25,154 boe/d for Q4/2020 which is 13,412 boe/d lower than 38,566 boe/d reported for Q4/2019. The decrease in production reflects lower exploration and development activity throughout 2020 relative to 2019. Our realized price of $38.41/boe was $13.92/boe lower than our realized price of $52.33/boe in Q4/2019 due to a decrease in benchmark prices in Q4/2020 relative to Q4/2019. The MEH benchmark averaged US$43.05/bbl in Q4/2020 which is US$16.99/boe lower than US$60.04/bbl during Q4/2019. Operating netback of $44.8 million ($19.38/boe) was $65.8 million ($11.79/boe) lower than $110.6 million ($31.17/boe) for Q4/2019 due to lower benchmark prices and lower production in Q4/2020. Exploration and development expenditures of $32.8 million in Q4/2020 includes costs associated with drilling 26 (7.1 net) wells and commencing production from 9 (2.7 net) wells. Exploration and development expenditures were lower in Q4/2020 due to lower completion activity and a reduction in well costs relative to Q4/2019 when we spent $48.7 million and drilled 27 (6.3 net) wells and brought 24 (6.5 net) wells on production.

We generated adjusted funds flow of $82.2 million in Q4/2020 which is $150.0 million lower than $232.1 million in Q4/2019. The decrease in adjusted funds flow in Q4/2020 is due to lower realized pricing driven by the decline in benchmark pricing along with lower production due to lower capital spending in 2020. Production of 70,475 boe/d in Q4/2020 compared to 96,360 boe/d for Q4/2019 was a result of limited exploration and development activity during Q2/2020 and Q3/2020 relative to the same periods of 2019. Operating netback of $15.19/boe in Q4/2020 is $12.11/boe lower relative to $27.30/boe in Q4/2019 and reflects the impact that lower benchmark prices had on our realized pricing. The decrease in our realized price combined with the impact of lower production resulted in an $143.5 million decrease in operating netback in Q4/2020 compared to Q4/2019. We recorded a realized financial derivatives gain of $17.1 million in Q4/2020 compared to $23.0 million in Q4/2019. G&A expense of $9.3 million in Q4/2020 was lower than $9.9 million in Q4/2019 due to lower staffing and our cost saving initiatives, which included salary reductions. Interest expense of $25.2 million in Q4/2020 was $0.8 million higher than $24.4 million for Q4/2019 due to an increase in interest on long-term notes, partially offset by a reduction in interest on our credit facilities due to lower interest rates in Q4/2020 relative to Q4/2019. Net debt decreased from $1.87 billion in Q4/2019 to $1.85 billion in Q4/2020 due to the strengthening of the Canadian dollar relative to the U.S. dollar combined with debt repayment with free cash flow generated during 2020.

We recorded net income of $221.2 million in Q4/2020 compared to a net loss of $117.8 million in Q4/2019. Net income for Q4/2020 includes $341.3 million associated with the reversal of impairments due to a decrease in well costs in our Eagle Ford and Viking business units. In Q4/2019 we recorded an impairment expense of $187.8 million due to the sustained decline in Canadian heavy oil prices which resulted in a change in development plans for our thermal projects in Peace River.

QUARTERLY FINANCIAL INFORMATION

	2020				2019			
($ thousands, except per common share amounts)	**Q4**	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Petroleum and natural gas sales	**233,636**	252,538	152,689	336,614	445,895	424,600	482,000	453,424
Net income (loss)	**221,160**	(23,444)	(138,463)	(2,498,217)	(117,772)	15,151	78,826	11,336
Per common share - basic	**0.39**	(0.04)	(0.25)	(4.46)	(0.21)	0.03	0.14	0.02
Per common share - diluted	**0.39**	(0.04)	(0.25)	(4.46)	(0.21)	0.03	0.14	0.02
Adjusted funds flow	**82,176**	78,508	17,887	132,935	232,147	213,379	236,130	220,770
Per common share - basic	**0.15**	0.14	0.03	0.24	0.42	0.38	0.42	0.40
Per common share - diluted	**0.15**	0.14	0.03	0.24	0.42	0.38	0.42	0.40
Exploration and development	**77,809**	15,902	9,852	176,777	153,117	139,085	106,246	153,843
Canada	**45,030**	3,882	2,929	123,110	104,460	96,774	68,259	104,870
U.S.	**32,779**	12,020	6,923	53,667	48,657	42,311	37,987	48,973
Acquisitions, net of divestitures	**(33)**	(98)	(11)	(40)	563	(30)	1,647	—
Net debt	**1,847,601**	1,906,079	1,994,953	2,051,617	1,871,791	1,971,339	2,028,686	2,175,241
Total assets	**3,408,096**	3,156,414	3,267,820	3,441,040	5,914,083	6,233,875	6,222,190	6,359,157
Common shares outstanding	**561,227**	561,163	560,545	560,483	558,305	557,972	556,798	555,872
Daily production								
Total production (boe/d)	**70,475**	77,814	72,508	98,452	96,360	94,927	98,402	101,115
Canada (boe/d)	**45,321**	49,164	37,691	62,262	57,794	58,134	58,580	60,018
U.S. (boe/d)	**25,154**	28,650	34,817	36,190	38,566	36,793	39,822	41,097
Benchmark prices								
WTI oil (US$/bbl)	**42.66**	40.93	27.85	46.17	56.96	56.45	59.81	54.90
WCS heavy ($/bbl)	**43.46**	42.40	22.70	34.48	54.29	58.39	65.73	56.64
Edmonton Light ($/bbl)	**50.24**	49.83	29.85	51.43	58.10	68.41	73.84	66.53
CAD/USD avg exchange rate	**1.3031**	1.3316	1.3860	1.3445	1.3201	1.3207	1.3376	1.3293
AECO gas ($/mcf)	**2.77**	2.18	1.91	2.14	2.34	1.04	1.17	1.94
NYMEX gas (US$/mmbtu)	**2.66**	1.98	1.72	1.95	2.50	2.23	2.64	3.15
Sales price ($/boe)	**34.35**	33.79	22.31	35.19	48.25	47.14	51.49	47.98
Royalties ($/boe)	**(5.83)**	(5.59)	(4.42)	(6.33)	(8.72)	(8.59)	(9.67)	(8.94)
Operating expense ($/boe)	**(12.30)**	(10.26)	(11.17)	(11.66)	(11.23)	(11.15)	(11.22)	(11.02)
Transportation expense ($/boe)	**(1.03)**	(0.89)	(0.76)	(1.15)	(1.00)	(1.13)	(1.33)	(1.46)
Operating netback ($/boe)	**15.19**	17.05	5.96	16.05	27.30	26.27	29.27	26.56
Financial derivatives gain (loss) ($/boe)	**2.64**	(1.36)	2.06	3.00	2.59	2.39	1.45	2.07
Operating netback after financial derivatives ($/boe)	**17.83**	15.69	8.02	19.05	29.89	28.66	30.72	28.63

Our results for the previous eight quarters reflect the disciplined execution of our development programs and management of production in response to fluctuations in the prices for the commodities we produce. Production was 101,115 boe/d during Q1/2019 as stable crude oil prices supported an active development program in Canada and the U.S. Production was relatively consistent in the quarters following Q1/2019 until we shut-in production in Canada and moderated the pace of activity in the U.S. after the sharp decline in crude oil prices in March 2020. Production of 70,475 boe/d for Q4/2020 reflects reduced capital spending in Q2/2020 and Q3/2020 in response to low commodity prices.

North American benchmark commodity prices were stable throughout 2019 and were relatively strong leading into Q1/2020 with the WTI benchmark price averaging US$57.53/bbl in January. Decisions made by Saudi Arabia and Russia to increase production of crude oil as demand was decreasing due to the spread of COVID-19 resulted in a sharp decline in global crude oil prices with WTI averaging US$27.85/bbl in Q2/2020. Prices improved during the second half of 2020 as OPEC+ agreed to reinstate production curtailments and measures to control the spread of COVID-19 were relaxed. Despite this recent improvement, commodity prices remained lower than Q1/2020 levels with WTI averaging US$42.66/bbl for Q4/2020. The impact of low commodity prices is reflected in our realized sales price of $34.35/boe for Q4/2020. Our development programs were significantly reduced in Canada and the U.S. for 2020 as a result of the decline in crude oil pricing with limited exploration and development spending during Q2/2020 and Q3/2020. Exploration and development spending of $77.8 million during Q4/2020 reflects the improving outlook for crude oil prices leading into 2021.

Adjusted funds flow is directly impacted by our average daily production and changes in benchmark commodity prices which are the basis for our realized sales price. Adjusted funds flow improved throughout 2019 due to increased production and strong well performance along with higher realizations associated with the higher weighting of light oil production. Adjusted funds flow of $82.2 million in Q4/2020 reflects the impact of lower commodity prices and reduced development expenditures which resulted in lower production relative to 2019.

Net debt can fluctuate on a quarterly basis depending on the timing of exploration and development expenditures, changes in our adjusted funds flow and the closing CAD/USD exchange rate which is used to translate our U.S. dollar denominated debt. Net debt has decreased from $2.2 billion at Q1/2019 to $1.8 billion at Q4/2020, which is primarily due to adjusted funds flow exceeding exploration and development expenditures by $381.3 million over the last eight quarters, which reflects our efforts to preserve liquidity during periods of challenging commodity prices. Our net debt has also been reduced by a decrease in the CAD/USD exchange rate used to translate our U.S. dollar denominated debt from 1.3360 CAD/USD at Q1/2019 to 1.2755 CAD/USD at Q4/2020.

OFF BALANCE SHEET TRANSACTIONS

We do not have any financial arrangements that are excluded from the consolidated financial statements as at December 31, 2020, nor are any such arrangements outstanding as of the date of this MD&A.

CRITICAL ACCOUNTING ESTIMATES

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

Reserves

The Company uses estimates of oil, natural gas and NGL reserves in the calculation of depletion and in the determination of fair value estimates for non-financial assets. The process to estimate reserves is complex and requires significant judgment. Estimates of the Company's reserves are evaluated annually by independent reserves evaluators and represent the estimated recoverable quantities of oil, natural gas and NGL 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 NGL and their future net cash flows are based on a number of factors and assumptions. Changes to estimates and assumptions such as forward price forecasts, production rates, ultimate reserve recovery, timing and amount of capital expenditures, production costs, marketability of oil and natural gas, royalty rates and other geological, economic and technical factors could have a significant impact on reported reserves. Changes in the Company's reserves estimates can have a significant impact on the carrying values of the Company's oil and gas properties, the calculation of depletion, the timing of cash flows for asset retirement obligations, asset impairments and estimates of fair value determined in accounting for business combinations.

Cash-generating Units ("CGUs")

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

Identification of Impairment and Impairment Reversal Indicators

Judgment is required to assess when indicators of impairment or impairment reversal exist and when a calculation of the recoverable amount is required. The CGUs comprising oil and gas properties are reviewed at each reporting date to assess whether there is any indication of impairment or impairment reversal. The assessment for each CGU considers significant changes in reservoir performance including forecasted production volumes, forecasted royalty, operating, capital and abandonment and reclamation costs, forecasted oil and gas prices and the resulting cash flows from proved plus probable oil and gas reserves.

Measurement of Recoverable Amount

If indicators of impairment or impairment reversal are determined to exist, the recoverable amount of an asset or CGU is calculated based on the higher of value-in-use ("VIU") and fair value less cost of disposal ("FVLCD"). These calculations require the use of estimates and assumptions including cash flows associated with proved plus probable oil and gas reserves, the discount rate used to present value future cash flows, and assumptions regarding the timing and amount of capital 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.

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.

CHANGES IN SIGNIFICANT ACCOUNTING POLICIES

Business Combinations

Baytex adopted amendments to IFRS 3 Business Combinations effective January 1, 2020, which will be applied prospectively to acquisitions that occur on or after January 1, 2020. These amendments did not result in changes to the Company's accounting policies for applying the acquisition method but could result in future acquisitions being accounted for as an asset acquisition as opposed to a business combination.

NYSE LISTING

On March 24, 2020 we received notice from the New York Stock Exchange (“NYSE”) that Baytex was no longer in compliance with one of the NYSE’s continued listing standards because the average closing price of Baytex’s common shares was less than US$1.00 per share over a consecutive 30-day trading period. Baytex did not regain compliance and its common shares were delisted from the NYSE on December 3, 2020.

Baytex's common share remain registered with the U.S. Securities and Exchange Commission. However, provided that Baytex remains listed on the TSX and the average daily trading volume of Baytex’s common shares in the U.S. is less than 5% of Baytex’s worldwide average daily trading volume over the 12-month period following the delisting, Baytex may be eligible to deregister its common shares at that time. Deregistration of Baytex's common shares would terminate its reporting obligations under the Securities Exchange Act of 1934, as amended.

NON-GAAP AND CAPITAL MEASUREMENT MEASURES

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

Adjusted Funds Flow

We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for 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.

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)	**2020**	2019
Cash flow from operating activities	**$ 353,096**	$ 834,939
Change in non-cash working capital	**(48,758)**	52,070
Asset retirement obligations settled	**7,168**	15,417
Adjusted funds flow	**$ 311,506**	$ 902,426

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 are 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)	**2020**	2019
Cash flow used in investing activities	**$ 314,469**	$ 617,508
Change in non-cash working capital	**(32,031)**	(62,485)
Proceeds from dispositions	**182**	1,487
Property acquisitions	**—**	(3,667)
Additions to other plant and equipment	**(2,280)**	(552)
Exploration and development expenditures	**$ 280,340**	$ 552,291

Free Cash Flow

We define free cash flow as adjusted funds flow less exploration and development expenditures (both non-GAAP measures defined above), payments on lease obligations and asset retirement obligations settled. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition opportunities.

The following table provides our computation of free cash flow.

	Years Ended December 31	
($ thousands)	**2020**	2019
Adjusted funds flow	**$ 311,506**	$ 902,426
Exploration and development expenditures	**(280,340)**	(552,291)
Payments on lease obligations	**(5,925)**	(5,956)
Asset retirement obligations settled	**(7,168)**	(15,417)
Free cash flow	**$ 18,073**	$ 328,762

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 credit facilities and long-term notes outstanding, including trade and other payables, cash, and trade and other receivables. We use the principal amounts of the credit facilities and long-term notes outstanding in the calculation of net debt as these amounts represent our total repayment obligation at maturity. The carrying amount of debt issue costs associated with the credit facilities and long-term notes are 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, 2020**	December 31, 2019
Credit facilities (1)	**$ 651,173**	$ 506,471
Long-term notes (1)	**1,147,950**	1,337,200
Trade and other payables	**155,955**	207,454
Cash	**—**	(5,572)
Trade and other receivables	**(107,477)**	(173,762)
Net debt	**$ 1,847,601**	$ 1,871,791

(1) Principal amount of instruments expressed in Canadian dollars.

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)	**2020**	2019
Petroleum and natural gas sales	**$ 975,477**	$ 1,805,919
Blending and other expense	**(48,381)**	(68,795)
Total sales, net of blending and other expense	**927,096**	1,737,124
Royalties	**(163,735)**	(320,241)
Operating expense	**(331,345)**	(397,716)
Transportation expense	**(28,437)**	(43,942)
Operating netback	**403,579**	975,225
Realized financial derivatives gain	**47,836**	75,620
Operating netback after realized financial derivatives	**$ 451,415**	$ 1,050,845

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 on a twelve-month rolling basis.

	Years Ended December 31	
($ thousands)	**2020**	2019
Net income (loss)	**$ (2,438,964)**	$ (12,459)
Plus:		
Financing and interest	**125,441**	125,865
Unrealized foreign exchange loss (gain)	**9,232**	(62,753)
Unrealized financial derivatives loss	**18,500**	82,817
Current income tax expense	**574**	2,093
Deferred income tax recovery	**(160,967)**	(68,555)
Depletion and depreciation	**486,380**	731,686
Gain on dispositions	**(901)**	(2,238)
Impairment	**2,360,220**	187,822
Non-cash items (1)	**15,339**	27,048
Bank EBITDA	**$ 414,854**	$ 1,011,326

(1) Non-cash items include share-based compensation, exploration and evaluation expense, note redemption premiums, interest on lease obligations, and non-cash other income.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

As of December 31, 2020, 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 Rules 13a-15(f) and 15d-15(f) of 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, 2020.

The effectiveness of our internal control over financial reporting as of December 31, 2020 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their Report of Independent Registered Public Accounting Firm.

Changes in Internal Control over Financial Reporting

No changes were made to our internal control over financial reporting during the year ended December 31, 2020 that have materially affected, or are reasonably likely to materially affect, the internal controls 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)		**2020**		2019		2018
Revenues, net of royalties	**$**	**811,742**	$	1,485,678	$	1,115,116
Adjusted funds flow	**$**	**311,506**	$	902,426	$	472,983
Per common share - basic	**$**	**0.56**	$	1.62	$	1.35
Per common share - diluted	**$**	**0.56**	$	1.62	$	1.35
Net income (loss)	**$**	**(2,438,964)**	$	(12,459)	$	(325,309)
Per common share - basic	**$**	**(4.35)**	$	(0.02)	$	(0.93)
Per common share - diluted	**$**	**(4.35)**	$	(0.02)	$	(0.93)
Total assets	**$**	**3,408,096**	$	5,914,083	$	6,377,198
Credit facilities - principal	**$**	**651,173**	$	506,471	$	522,294
Long term notes - principal	**$**	**1,147,950**	$	1,337,200	$	1,596,323
Average wellhead prices, net of blending costs ($/boe)	**$**	**31.75**	$	48.72	$	46.31
Total production (boe/d)		**79,781**		97,680		80,458

FORWARD-LOOKING STATEMENTS

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

Specifically, this document contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; our capital budget and expected average daily production for 2021; our expected royalty rate and operating, transportation, general and administrative and interest expenses for 2021; our expected lease expenditures and asset retirement obligations settled in 2021; 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 we may issue or repurchase debt or equity securities from time to time or sell assets; our intent to fund certain financial obligations with cash flow from operations and the expected timing of the financial obligations; our plans with respect to asset retirement obligation activities; and that we may be eligible to deregister our common shares under the Securities Exchange Act of 1934. In addition, information and statements relating to reserves are deemed to be forward-looking statements, as they involve implied assessment, based on certain estimates and assumptions, that the reserves described exist in quantities predicted or estimated, and that the reserves can be profitably produced in the future.

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

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (including the impacts of Covid-19); the availability and cost of capital or borrowing; risks associated with our ability to exploit our properties and add reserves; availability and cost of gathering, processing and pipeline systems; that our credit facilities may not provide sufficient liquidity or may not be renewed; failure to comply with the covenants in our debt agreements; risks associated with a third-party operating our Eagle Ford properties; public perception and its influence on the regulatory regime; restrictions or costs imposed by climate change initiatives and the physical risks of climate change; 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; costs to develop and operate our properties; variations in interest rates and foreign exchange rates; risks associated with our hedging activities; retaining or replacing our leadership and key personnel; 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 related to our thermal heavy oil projects; alternatives to and changing demand for petroleum products; risks associated with our use of information technology systems; results of litigation; risks associated with large projects; 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, 2020, to be filed with Canadian securities regulatory authorities and the U.S. Securities and Exchange Commission not later than March 31, 2021 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 and operational results. Listed below is a description of these risks and uncertainties.

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, OPEC+, the condition of the Canadian, United States, European and Asian economies (including conditions resulting from the impact of the COVID-19), 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, storage capacity, 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 or tidewater to access world markets 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 Canadian GAAP. If crude oil and natural gas forecast prices change, the carrying value of our assets could be subject to revision and our net earnings could be adversely affected.

Availability and cost of capital or borrowing to maintain and/or fund future development and acquisitions

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 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.

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. This 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 or equity. 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. Additionally, from time to time, we may issue securities from treasury in order to reduce debt, complete acquisitions and/or optimize our capital structure.

Our success is highly dependent on our ability to exploit existing properties and add to our oil and natural gas reserves

Our oil and natural gas reserves are a depleting resource and decline as such reserves are produced, as a result, our long-term commercial success depends on our ability to find, acquire, develop and commercially produce oil and natural gas 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. 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 from operating activities to varying degrees.

There is no assurance we will be successful in developing our 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 reserve life of our properties will decline, which may adversely affect our business, financial condition, results of operations and prospects.

The amount of oil and natural gas that we can produce and sell is subject to the availability and cost of gathering, processing and pipeline systems

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. A significant change may result from the conversion of most of the capacity on the Enbridge mainline from the common carrier model, which will end on July 1, 2021, to a contracted service model, where only shippers who sign long term transportation agreements will have access.

Access to the pipeline capacity for the export of crude oil from Canada has, at times, been inadequate for the amount of Canadian production being exported. This has resulted in significantly lower prices being realized by Canadian producers compared with the WTI price and the Brent 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 obtain global benchmark pricing for 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, derailment or blockades 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 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.

Our Credit Facilities may not provide sufficient liquidity and a failure to renew our Credit Facilities at maturity could adversely affect our financial condition

Our Credit Facilities and any replacement credit facilities may not provide sufficient liquidity. The amounts available under our Credit Facilities may not be sufficient for future operations, or we may not be able to obtain additional financing on economic terms, 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 April 2, 2024, 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.

Failure to comply with the covenants in the agreements governing our debt, including our obligation to repay the Senior Notes at maturity, could adversely affect our financial condition

We are required to comply with the covenants in our Credit Facilities and the Senior Notes. If we fail to comply with such covenants, are unable to pay, repay or refinance amounts owned at maturity or 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 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.

We are not the operator of our drilling locations in our Eagle Ford acreage and, therefore, we will not be able to control the timing of development, associated costs or the rate of production of that acreage

Marathon Oil 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 well.

Public perception and its 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, rail car derailments, 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.

Restrictions and/or costs associated with regulatory initiatives to combat climate change and the physical risks of climate change may have a material adverse affect on our business

Regulatory and Policy Initiatives

Our exploration and production facilities and other operational activities emit GHGs. 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 our financial condition, results of operations or prospects.

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.

Physical Risk

Climate change has been linked to extreme weather conditions. Extreme hot and cold weather, heavy snowfall, heavy rain fall, hurricanes and wildfires may restrict our ability to access our properties, cause operational difficulties including damage to machinery and facilities. Extreme weather also increases the risk of personnel injury as a result of dangerous working conditions. Certain of our assets are located where they are exposed to forest fires, floods, heavy rains, hurricanes and other extreme weather conditions which can lead to significant downtime, damage to such assets and/or increased costs of construction and maintenance. Moreover, extreme weather conditions may lead to disruptions in our ability to transport produced oil and natural gas as well as goods and services in our supply chain.

New regulations on hydraulic fracturing may lead to operational delays, increased costs and/or decreased production volumes

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. Hydraulic fracturing has featured prominently in recent political, media and activist commentary on the subject of water usage, induced seismicity events and environmental damage. 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 Corporation'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 we are ultimately able to produce from our reserves.

Regulatory water use restrictions and/or limited access to water or other fluids may impact the Corporation's ability to fracture its wells or carry out waterflood operations

The Corporation undertakes or intends to undertake certain hydraulic fracturing, SAGD, CCS and waterflooding programs. To undertake such operations the Corporation needs to have access to sufficient volumes of water, or other liquids. There is no certainty that the Corporation 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, SAGD, CCS and waterflooding. If the Corporation is unable to access such water it may not be able to undertake hydraulic fracturing, SAGD, CCS or waterflooding activities, which may reduce the amount of oil and natural gas that the Corporation is ultimately able to produce from its reserves.

Changes in government controls, legislation or regulations that affect the oil and gas industry, or failing to comply with such controls, legislation or regulations, could adversely affect us

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.

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) and the *Hart-Scott-Rodino Antitrust Improvements Act* in the United States.

Regulations regarding the disposal of fluids used in the Corporation's operations may increase its costs of compliance or subject it to regulatory penalties or litigation

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, provincial and state 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 Corporation's costs of compliance.

The oil and gas industry is highly regulated and changes in environmental, health and safety controls, legislation or regulations may impose restrictions, costs or other liabilities

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 jurisdictions where we operate 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. 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.

Our financial performance is significantly affected by the cost of developing and operating our assets

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, the cost of new technologies, supply chain disruptions and 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. Increases to development and operating costs could have a material adverse effect on our financial condition, results of operations or prospects.

Variations in interest rates and foreign exchange rates could adversely affect our financial condition

There is a risk that 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 prospects.

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 a large portion of our indebtedness is 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.

Our hedging activities may negatively impact our income and our financial condition

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.

Failure to retain or replace our leadership and key personnel may have an adverse affect on our business

Our success is dependent upon our management, our leadership capabilities and the quality and competency of our talent. If we are unable to retain key personnel and critical talent or to attract and retain new talent with the necessary leadership, professional and technical competencies, it could have a material adverse effect on our financial condition, results of operations and prospects.

Income tax laws or other laws or government incentive programs or regulations relating to our industry may in the future be changed or interpreted in a manner that adversely affects us and our Shareholders

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 our financial condition, results of operations and prospects.

There are numerous uncertainties inherent in estimating quantities of recoverable oil and natural gas reserves, including many factors beyond our control

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

All such estimates are, to some degree, uncertain and classifications of reserves are only attempts to define the degree of uncertainty involved. For these reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, the classification of such reserves based on risk of recovery and estimates of future net revenues expected therefrom, prepared by different engineers or by the same engineers at different times, may vary substantially. Our reserves as at December 31, 2020 are estimated using forecast prices and costs. If we realize lower prices for crude oil, natural gas liquids and natural gas and they are substituted for the estimated price assumptions, 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.

Acquiring, developing and exploring for oil and natural gas involves many physical hazards. We have not insured and cannot fully insure against all risks related to our operations

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, theft 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.

We are subject to risk of default by the counterparties to our contracts and our counterparties may deem us to be a default 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 flow from operating activities 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.

Our thermal heavy oil projects face additional risks compared to conventional oil and gas production

Our thermal heavy oil projects are capital intensive projects which rely on specialized production technologies. Certain current technologies for the recovery of heavy oil, such as CSS and SAGD, 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 CSS, SAGD or other new technologies to become uneconomic, which could have an adverse effect on our financial condition and our reserves. 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 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.

The adoption of alternatives to and changing demand for petroleum products may have an adverse affect on our business

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 effect on the demand for oil and gas products. The Corporation 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 Corporation's business and financial condition by decreasing its cash flow from operating activities and the value of its assets.

Our information technology systems are subject to certain 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.

Adverse results from litigation may have an adverse affect on our business

In the normal course of our operations, we may become involved in, named as a party to, or be the subject of, various legal proceedings, including regulatory proceedings, tax proceedings and legal actions. Potential litigation may develop in relation to personal injuries, property damage, royalties, taxes, land and access rights, environmental issues, natural resource damages and contract disputes. The outcome with respect to outstanding, pending or future proceedings cannot be predicted with certainty and may be determined adversely to us and could have a material adverse effect on our assets, liabilities, business, financial condition and results of operations. Even if we prevail in any such legal proceedings, the proceedings could be costly and time-consuming and may divert the attention of management and key personnel from business operations, which could have an adverse affect on our financial condition.

We may participate in larger projects and may have more concentrated risk in certain areas of our operations

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.

Risks Related to Ownership of our Securities

Changes in market-based factors may adversely affect the trading price of the Common Shares

The market price of our Common Shares is sensitive to a variety of market-based factors including, but not limited to, commodity prices, interest rates, foreign exchange rates, the decision of certain indices to include our Common Shares and the comparability of the Common Shares to other securities. Any changes in these market-based factors may adversely affect the trading price of the Common Shares.

Forward-Looking Information rely upon assumptions which may not prove correct

Shareholders and prospective investors are cautioned not to place undue reliance on our forward-looking information. By its nature, forward-looking information involves numerous assumptions, known and unknown risks and uncertainties, of both a general and specific nature, that could cause actual results to differ materially from those suggested by the forward-looking information or contribute to the possibility that predictions, forecasts or projections will prove to be materially inaccurate.

Certain Risks for United States and other non-resident Shareholders

The ability of investors resident in the United States to enforce civil remedies is limited

We are a corporation incorporated under the laws of the Province of Alberta, Canada, our principal office is located in Calgary, Alberta and a substantial portion of our assets are located outside the United States. Most of our directors and officers and the representatives of the experts who provide services to us (such as our auditors and our independent qualified reserves evaluators), and all or a substantial portion of their assets are located outside the United States. As a result, it may be difficult for investors in the United States to effect service of process within the United States upon such directors, officers and representatives of experts who are not residents of the United States or to enforce against them judgments of the United States courts based upon civil liability under the United States federal securities laws or the securities laws of any state within the United States. There is doubt as to the enforceability in Canada against us or any of our directors, officers or representatives of experts who are not residents of the United States, in original actions or in actions for enforcement of judgments of United States courts of liabilities based solely upon the United States federal securities laws or securities laws of any state within the United States.

Canadian and United States practices differ in reporting reserves and production and our estimates may not be comparable to those of companies in the United States

We report our production and reserves quantities in accordance with Canadian practices and specifically in accordance with NI 51-101. These practices are different from the practices used to report production and to estimate reserves in reports and other materials filed with the SEC by companies in the United States.

We incorporate additional information with respect to production and reserves which is either not required to be included or prohibited under rules of the SEC and practices in the United States. We follow the Canadian practice of reporting gross production and reserve volumes (before deduction of Crown and other royalties). We also follow the Canadian practice of using forecast prices and costs when we estimate our reserves, whereas the SEC rules require that a 12-month average price, calculated as the unweighted arithmetic average of the first-day-of-the-month price for each month within the 12-month period prior to the end of the reporting period, be utilized.

We have included in this AIF estimates of proved reserves and proved plus probable reserves. Probable reserves have a lower certainty of recovery than proved reserves. The SEC requires oil and gas issuers in their filings with the SEC to disclose only proved reserves but permits the optional disclosure of probable reserves. The SEC definitions of proved reserves and probable reserves are different than NI 51-101; therefore, proved, probable and proved plus probable reserves disclosed in this AIF may not be comparable to United States standards.

As a consequence of the foregoing, our reserves estimates and production volumes in this AIF may not be comparable to those made by companies utilizing United States reporting and disclosure standards.

There is additional taxation applicable to non-residents

Tax legislation in Canada may impose withholding or other taxes on the cash dividends, stock dividends or other property transferred by us to non-resident shareholders. These taxes may be reduced pursuant to tax treaties between Canada and the non-resident shareholder's jurisdiction of residence. Evidence of eligibility for a reduced withholding rate must be filed by the non-resident shareholder in prescribed form with their broker (or in the case of registered shareholders, with the transfer agent). In addition, the country in which the non-resident shareholder is resident may impose additional taxes on such dividends. Any of these taxes may change from time to time.