BAYTEX

RESILIENT. COMMITTED. SUSTAINABLE.

2020

Annual Report

TSX BTE

OUR HIGHLIGHTS

79,781 boe/d
for the full-year 2020

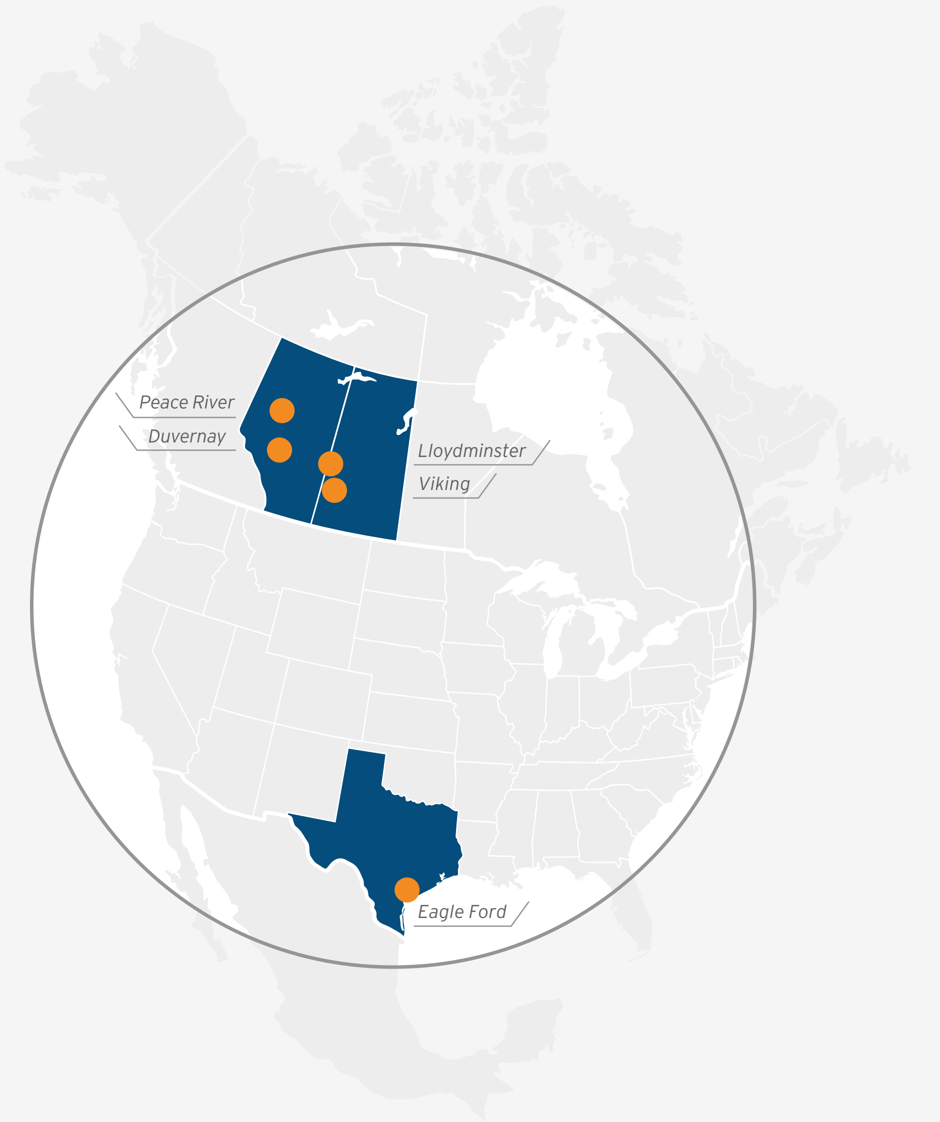
$18 million
free cash flow

Extended
long-term note and credit facility maturities to 2024

$319 million
liquidity

46%
reduction in GHG emissions intensity, relative to our 2018 baseline

OUR OPERATING AREAS



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SUMMARY

	Twelve Months Ended	
	December 31, 2020	December 31, 2019
FINANCIAL (thousands of Canadian dollars, except per common share amounts)		
Petroleum and natural gas sales	**$ 975,477**	$ 1,805,919
Adjusted funds flow [(1)]	**311,506**	902,426
Per share – basic	**0.56**	1.62
Per share – diluted	**0.56**	1.62
Net income (loss)	**(2,438,964)**	(12,459)
Per share – basic	**(4.35)**	(0.02)
Per share – diluted	**(4.35)**	(0.02)
Capital Expenditures		
Exploration and development expenditures [(1)]	**$ 280,340**	$ 552,291
Acquisitions, net of divestitures	**(182)**	2,180
Total oil and natural gas capital expenditures	**$ 280,158**	$ 554,471
Net Debt		
Credit facilities	**$ 651,173**	$ 506,471
Long-term notes	**1,147,950**	1,337,200
Long-term debt	**1,799,123**	1,843,671
Working capital deficiency	**48,478**	28,120
Net debt [(1)]	**$ 1,847,601**	$ 1,871,791
Shares Outstanding - basic (thousands)		
Weighted average	**560,657**	557,048
End of period	**561,227**	558,305

	Twelve Months Ended	
	December 31, 2020	December 31, 2019
OPERATING		
Daily Production		
Light oil and condensate (bbl/d)	**37,056**	43,587
Heavy oil (bbl/d)	**21,142**	26,741
NGL (bbl/d)	**7,340**	10,229
Total liquids (bbl/d)	**65,538**	80,557
Natural gas (mcf/d)	**85,464**	102,742
Oil equivalent (boe/d @ 6:1) [2]	**79,781**	97,680
Netback (thousands of Canadian dollars)		
Total sales, net of blending and other expense [3]	**$ 927,096**	$ 1,737,124
Royalties	**(163,735)**	(320,241)
Operating expense	**(331,345)**	(397,716)
Transportation expense	**(28,437)**	(43,942)
Operating netback [1]	**$ 403,579**	$ 975,225
General and administrative	**(34,268)**	(45,469)
Cash financing and interest	**(106,534)**	(107,417)
Realized financial derivatives gain (loss)	**47,836**	75,620
Other [4]	**893**	4,467
Adjusted funds flow [1]	**$ 311,506**	$ 902,426
Netback (per boe)		
Total sales, net of blending and other expense [3]	**$ 31.75**	$ 48.72
Royalties	**(5.61)**	(8.98)
Operating expense	**(11.35)**	(11.16)
Transportation expense	**(0.97)**	(1.23)
Operating netback [1]	**$ 13.82**	$ 27.35
General and administrative	**(1.17)**	(1.28)
Cash financing and interest	**(3.65)**	(3.01)
Realized financial derivatives gain (loss)	**1.64**	2.12
Other [4]	**0.03**	0.13
Adjusted funds flow [1]	**$ 10.67**	$ 25.31

Notes:

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

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

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

(4) Other is comprised of realized foreign exchange gain or loss, other income or expense, current income tax expense or recovery and share-based compensation. Refer to the 2020 MD&A for further information on these amounts.

Advisory Regarding Forward-Looking Statements

In the interest of providing Baytex's shareholders and potential investors with information regarding Baytex, including management's assessment of Baytex's future plans and operations, certain statements in this report 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 "believe", "continue", ""estimate", "expect", "forecast", "intend", "may", "objective", "ongoing", "outlook", "potential", "project", "plan", "should", "target", "would", "will" or similar words suggesting future outcomes, events or performance. The forward-looking statements contained in this report speak only as of the date thereof and are expressly qualified by this cautionary statement.

Specifically, this report contains forward-looking statements relating to but not limited to: our business strategies, plans and objectives; that we are on track to deliver $250 million ($0.45 per basic share) of free cash flow in 2021, are building operational momentum and executing our plan to maximize free cash flow and accelerate our debt reduction strategy; in 2021 that: we will benefit from a disciplined approach to capital allocation and a continued drive to improve our cost structure and capital efficiencies, our high graded capital program is focused on high netback light oil assets in the Viking and Eagle Ford and that, at current commodity prices, we intend to implement a heavy oil program in the second half of the year; our guidance for 2021 exploration and development expenditures, production, royalty rate, operating, transportation, general and administration and interest expense and leasing expenditures and asset retirement obligations; that 48% of our net crude oil exposure for 2021 is hedged; In 2021, we expect to benefit from our diversified oil weighted portfolio and our commitment to allocate capital effectively and that our priority is to generate stable production, maximize free cash flow and further strengthen our balance sheet; for 2021 in the Eagle Ford: we expect to bring wells drilled in Q4/2020 on stream in Q1/2021 and bring 18 net wells on production; in the Viking: that we expect to bring 43 net wells on stream in Q1/2020 and 120 net wells on stream in 2021; we have minimal heavy oil development scheduled in H1/2021 and, at current commodity prices, we intend to implement a drilling program in H2/2021 with upwards of 30 net wells drilled at Lloydminster and 6 net wells drilled at Peace River; in Pembina Duvernay we have flexibility to drill up to 4 net wells in H2/2021; based on the forward strip, we expect to increase our financial liquidity to approximately $500 million in 2021; that we use financial derivative contracts and crude-by-rail to reduce adjusted funds flow volatility and the percentage of our expected production in 2021 of Canadian light oil and heavy oil for which we have hedged the differential to WTI; our 2025 GHG emissions intensity reduction target and our strategy to reach the target; that we plan to publish our fifth corporate sustainability report this year; future development costs, F&D and FD&A; our reserves life index; forecast prices for oil and natural gas; forecast inflation and exchange rates; the net present value before income taxes of the future net revenue attributable to our reserves; the value of our undeveloped land holdings and our estimated net asset value. 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 they can be profitably produced in the future.

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

Actual results achieved will vary from the information provided herein as a result of numerous known and unknown risks and uncertainties and other factors. Such factors include, but are not limited to: the volatility of oil and natural gas prices and price differentials (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.

All amounts in this report are stated in Canadian dollars unless otherwise specified.

Non-GAAP Financial and Capital Management Measures

In this report, we refer to certain financial measures (such as adjusted funds flow, exploration and development expenditures, free cash flow, net debt and operating netback) which do not have any standardized meaning prescribed by Canadian GAAP (''non-GAAP measures'') and are considered non-GAAP measures. While adjusted funds flow, exploration and development expenditures, free cash flow, net debt and operating netback are commonly used in the oil and gas industry, our determination of these measures may not be comparable with calculations of similar measures for other issuers.

Adjusted funds flow is not a measurement based on generally accepted accounting principles ("GAAP") in Canada, but is a financial term commonly used in the oil and gas industry. We define adjusted funds flow as cash flow from operating activities adjusted for changes in non-cash operating working capital and asset retirement obligations settled. Our determination of adjusted funds flow may not be comparable to other issuers. We consider adjusted funds flow a key measure that provides a more complete understanding of operating performance and our ability to generate funds for exploration and development expenditures, debt repayment, settlement of our abandonment obligations and potential future dividends.

In addition, we use a ratio of net debt to adjusted funds flow to manage our capital structure. We eliminate settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on our capital programs and the maturity of our operating areas. The settlement of abandonment obligations are managed with our capital budgeting process which considers available adjusted funds flow. Changes in non-cash working capital are eliminated in the determination of adjusted funds flow as the timing of collection, payment and incurrence is variable and by excluding them from the calculation we are able to provide a more meaningful measure of our cash flow on a continuing basis. For a reconciliation of adjusted funds flow to cash flow from operating activities, see Management's Discussion and Analysis of the operating and financial results for the year ended December 31, 2020.

Exploration and development expenditures is not a measurement based on GAAP in Canada. We define exploration and development expenditures as additions to exploration and evaluation assets combined with additions to oil and gas properties. Our definition of exploration and development expenditures may not be comparable to other issuers. 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.

Free cash flow is not a measurement based on GAAP in Canada. We define free cash flow as adjusted funds flow less exploration and development expenditures (both non-GAAP measures discussed above), payments on lease obligations, and asset retirement obligations settled. Our determination of free cash flow may not be comparable to other issuers. We use free cash flow to evaluate funds available for debt repayment, common share repurchases, potential future dividends and acquisition and disposition opportunities.

Net debt is not a measurement based on GAAP in Canada. We define net debt to be the sum of cash, trade and other accounts receivable, trade and other accounts payable, and the principal amount of both the long-term notes and the credit facilities. Our definition of net debt may not be comparable to other issuers. We believe that this measure assists in providing a more complete understanding of our cash liabilities and provides a key measure to assess our liquidity. 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 ultimate repayment obligation at maturity. The carrying amount of debt issue costs associated with the credit facilities and long-term notes is excluded on the basis that these amounts have already been paid by Baytex at inception of the contract and do not represent an additional source of capital or repayment obligation.

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

MESSAGE TO SHAREHOLDERS

In one of the most challenging years experienced by our industry, we delivered on our commitment to preserve financial liquidity, capture cost savings and generate free cash flow. The Covid-19 pandemic required a dynamic response to the oil price collapse and our team delivered. We re-set our business in the face of extremely volatile crude oil markets and intensified efforts to improve all aspects of our cost structure and capital efficiencies, while protecting the health and safety of our personnel. We are now benefiting from these actions as we are poised to generate meaningful free cash flow in 2021 and continue our de-leveraging strategy.

In 2020, we reduced our capital budget by 50% and identified cost savings of approximately $100 million. We produced 79,781 boe/d (82% liquids) with capital expenditures of $280 million, in line with our annual guidance. We also hit all of our cost targets with operating expenses averaging $11.35/boe, transportation expenses of $0.97/boe and general and administrative expenses under $1.20/boe.

We generated free cash flow of $18 million and a $24 million net debt reduction (including the Canadian dollar strengthening relative to the U.S. dollar). We also negotiated a bank credit facility extension and refinanced our long-term notes, both important measures to ensure our financial liquidity. We issued US$500 million senior unsecured notes maturing April 2027 which enabled us to redeem two near term notes maturing in 2021 and 2022. As of December 31, 2020, we held $367 million of undrawn capacity on our credit facilities, resulting in liquidity, net of working capital, of $319 million. We are well within our financial covenants and our first long-term note maturity of US$400 million is not until June 2024.

In addition, we continue to build on our long term, high quality and diversified oil portfolio. Our operating teams are well established with a track record of enhancing our inventory and delivering results. Our proved plus probable reserves at year-end total 462 mmboe and we maintain a strong reserves life index of 17.9 years. In Canada, we have one of the largest conventional oil portfolios, including high operating netback, light oil production in the Viking and low decline, heavy oil production at Peace River and Lloydminster. We also hold a dominant land position in the emerging light oil resource play in the Pembina Duvernay, which has similar geologic and reservoir characteristics to our Eagle Ford shale asset in the United States. Our position in the Eagle Ford is defined by one of the highest quality, lowest-cost U.S. resource plays with outstanding drilling economics.

As part of our core values, we are driven to safely and responsibly develop energy resources while reducing environmental impact. In 2019, we established a GHG emissions reduction target. Our objective was to reduce our corporate GHG emission intensity (tonnes of CO2e per boe) by 30% by 2021, relative to our 2018 baseline. We are pleased to announce that we have exceeded this target, achieving a 46% reduction in our GHG emissions intensity through year-end 2020. This represents an annual reduction of 1.6 million tonnes of CO2e and is equivalent to taking 340,000 cars off the road annually.

As an element of our corporate culture we continue to set the bar higher. We have established a new target to reduce our corporate GHG emission intensity by a further 33% from current levels by 2025. This equates to an approximate 65% reduction by 2025, relative to our 2018 baseline. The entire organization is proud of our emissions reduction strategy which includes gas conservation and combustion, reusing associated gas as fuel for field activities, reduced emissions from storage tanks, along with monitoring and preventing fugitive emissions.

We look forward to publishing our fifth corporate sustainability report later this year. We are committed to transparency and accountability, as well as progressing the environmental and social aspects of our business.

Looking Forward

We maintain an attractive and deep inventory of development drilling locations with approximately ten years or more in each of our core assets. In 2021, we will benefit from a disciplined approach to capital allocation as well as our continued drive to improve our cost structure and capital efficiencies. Our high graded capital program is focused largely on our high netback light oil assets in the Viking and Eagle Ford. At current commodity prices, we intend to implement a heavy oil program in the second half of the year.

We are executing our plan to maximize free cash flow and accelerate our debt reduction strategy. Our 2021 guidance remains unchanged as we target production of 73,000 to 77,000 boe/d with exploration and development expenditures of $225 to $275 million. During Q4/2020, we resumed drilling activity, which is leading to operational momentum early in 2021 with current production over 78,000 boe/d. At the time of writing, we expect to generate over $250 million ($0.45 per basic share) of free cash flow in 2021 and increase our financial liquidity to over $550 million.

We maintain a consistent approach to risk management and marketing, utilizing various financial derivative contracts and crude-by-rail to reduce the volatility in our adjusted funds flow. For 2021, we have entered into hedges on approximately 48% of our net crude oil exposure, largely utilizing a 3-way option structure that provides WTI price protection at US$45/bbl with upside participation to US$52/bbl. We are also contracted to deliver 5,500 bbl/d of our heavy oil volumes to market by rail.

We continue to enhance our organizational capability at all levels - from the Board, to management and to all employees. I am particularly proud of our response to the Covid-19 pandemic as we strive to create a more sustainable business and prosperous future. Our team is resilient and focused and we are totally committed to generating value for shareholders.

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

Sincerely,

Edward D. LaFehr
President and Chief Executive Officer

February 24, 2021

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of the operating and financial results of Baytex Energy Corp. for the years ended December 31, 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.

MANAGEMENT'S ANNUAL REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of Baytex Energy Corp. (the "Company") is responsible for establishing and maintaining adequate internal control over financial reporting. Under the supervision of our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer we have conducted an evaluation of the effectiveness of our internal control over financial reporting based on the Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO"). Based on our assessment, we have concluded that as of December 31, 2020, our internal control over financial reporting was effective.

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

The effectiveness of the Company's internal control over financial reporting as of December 31, 2020 has been audited by KPMG LLP, the Company's Independent Registered Public Accounting Firm, who also audited the Company's consolidated financial statements for the year ended December 31, 2020.

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

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

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

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

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

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

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

February 24, 2021

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated statements of financial position of Baytex Energy Corp. (the "Company") as of December 31, 2020 and 2019, the related consolidated statements of loss and comprehensive loss, changes in equity, and cash flows for each of the years then ended, and the related notes (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2020 and 2019, and its financial performance and its cash flows for the years then ended, in conformity with International Financial Reporting Standards as issued by the International Accounting Standards Board.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the Company's internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 24, 2021 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

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

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

Critical Audit Matters

The critical audit matters communicated below are matters arising from the current period audit of the consolidated financial statements that were communicated or required to be communicated to the audit committee and that: (1) relate to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of critical audit matters does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matters below, providing separate opinions on the critical audit matters or on the accounts or disclosures to which they relate.

Assessment of the recoverable amount of of oil and gas properties

As discussed in note 6 to the consolidated financial statements, the Company recorded a total impairment charge of $2,247 million related to the Company's Conventional, Peace River, Lloydminster, Duvernay, Viking and Eagle Ford cash generating units (CGUs). The Company identified indicators of impairment as of March 31, 2020 and indicators of impairment reversal as of December 31, 2020 for each of its CGUs and determined the recoverable amount as of March 31, 2020 and December 31, 2020 of each of the CGUs. The determination of recoverable amount of a CGU involves numerous estimates, including cash flows associated with estimated proved and probable oil and gas reserves of the CGU ("CGU reserves") and the discount rate. The estimation of proved and probable oil and gas reserves involves the expertise of independent reserves evaluators, who take into consideration assumptions related to forecasted production volumes, royalty, operating and capital costs and commodity prices (collectively "reserve assumptions"). The Company engages independent reserves evaluators to estimate CGU reserves.

We identified the assessment of the recoverable amount of each of the Company's CGUs as a critical audit matter. Minor changes in reserve assumptions and discount rates could have had a significant impact on the estimate of recoverable amounts and the resulting impairment expense of the CGUs. A high degree of auditor judgment was required to evaluate the Company's estimates of CGU reserves, and related reserve assumptions, and the discount rates, which were inputs into the calculation of recoverable amounts. Additionally, the evaluation of these estimates required involvement of valuation professionals with specialized skills and knowledge.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to the

Company's determination of the recoverable amount of each of the CGUs, including controls over the determination of reserve assumptions and resulting cash flows of the CGU reserves and determination of the discount rate.

We evaluated the competence, capabilities and objectivity of the independent reserves evaluators engaged by the Company. We evaluated the methodology used by the independent reserves evaluators to estimate the CGU reserves for compliance with regulatory standards. We compared the current year actual CGU production volumes, royalty, operating and capital costs to those estimates used in the prior year estimate of proved reserves by CGU to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the estimate of the CGU reserves by comparing them to those published by other reserve engineering companies. We assessed the forecasted production volumes and forecasted royalty, operating and capital costs assumptions used in the current year estimate of the CGU reserves by comparing them to historical results. We involved valuation professionals with specialized skills and knowledge, who assisted in:

- evaluating the Company's discount rate, by comparing the discount rate against publicly available market data for comparable assets and assessing the resulting discount rate
- evaluating the Company's estimate of the aggregate recoverable amount of all CGUs by comparing the implied enterprise value to publicly available market data.

Impact of estimated oil and gas reserves on depletion expense related to oil and gas properties

As discussed in note 3 to the consolidated financial statements, the Company depletes its oil and gas properties using the unit-of-production method by depletable area. Under such method, capitalized costs are depleted over estimated proved and probable oil and gas reserves by depletable area ("area reserves"). As discussed in Note 6 to the consolidated financial statements, the Company recorded depletion expense related to oil and gas properties of $479 million for the year ended December 31, 2020. The estimation of area reserves requires the expertise of independent reserves evaluators who take into consideration reserve assumptions. The Company engages independent reserves evaluators to estimate area reserves.

We identified the assessment of the impact of estimated area reserves on depletion expense related to oil and gas properties as a critical audit matter. Changes in assumptions used to estimate area reserves could have had a significant impact on the calculation of depletion expense of the depletable area. A high degree of auditor judgment was required in evaluating the area reserves, and related reserve assumptions, which were used in the calculation of depletion expense.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls related to the critical audit matter. This included controls related to the calculation of depletion expense and the estimation of area reserves and related reserves assumptions.

We assessed the calculation of depletion expense for compliance with regulatory standards. We evaluated the competence, capabilities and objectivity of the independent reserves evaluators engaged by the Company. We evaluated the methodology used by the independent reserves evaluators to estimate area reserves for compliance with regulatory standards. We compared 2020 actual area production volumes, royalty, operating and capital costs to those estimates used in the prior year estimate of proved reserves by area to assess the Company's ability to accurately forecast. We assessed the forecasted commodity prices used in the estimate of area reserves by comparing them to those published by other reserves engineering companies. We assessed the forecasted production volumes and forecasted royalty, operating and capital costs assumptions used in the estimate of area reserves by comparing them to historical results.

KPMG LLP

Chartered Professional Accountants

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

Calgary, Canada
February 24, 2021

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

Opinion on Internal Control Over Financial Reporting

We have audited Baytex Energy Corp.'s (and subsidiaries') (the "Company") internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2020, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated statements of financial position of the Company as of December 31, 2020 and 2019, the related consolidated statements of loss and comprehensive loss, changes in equity, and cash flows for the years then ended, and the related notes (collectively, the consolidated financial statements), and our report dated February 24, 2021 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

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

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

Definition and Limitations of Internal Control Over Financial Reporting

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

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

KPMG LLP

Chartered Professional Accountants

Calgary, Canada
February 24, 2021

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

As at	Notes	December 31, 2020	December 31, 2019
ASSETS			
Current assets			
Cash		**$ —**	$ 5,572
Trade and other receivables		**107,477**	173,762
Financial derivatives	18	**5,057**	5,433
		112,534	184,767
Non-current assets			
Exploration and evaluation assets	5	**191,865**	320,210
Oil and gas properties	6	**3,077,548**	5,387,889
Other plant and equipment		**7,996**	7,598
Lease assets	7	**11,098**	13,619
Deferred income tax asset	15	**$ 7,055**	$ —
		$ 3,408,096	$ 5,914,083
LIABILITIES			
Current liabilities			
Trade and other payables		**$ 155,955**	$ 207,454
Financial derivatives	18	**26,792**	8,668
Lease obligations	7	**4,289**	5,798
Asset retirement obligations	10	**11,820**	11,579
		198,856	233,499
Non-current liabilities			
Credit facilities	8	**649,221**	505,412
Long-term notes	9	**1,132,868**	1,328,175
Lease obligations	7	**6,787**	8,085
Asset retirement obligations	10	**748,563**	656,395
Deferred income tax liability	15	**93,588**	235,308
		2,829,883	2,966,874
SHAREHOLDERS' EQUITY			
Shareholders' capital	11	**5,729,418**	5,718,835
Contributed surplus		**14,345**	17,712
Accumulated other comprehensive income		**618,976**	556,224
Deficit		**(5,784,526)**	(3,345,562)
		578,213	2,947,209
		$ 3,408,096	$ 5,914,083

Commitments (note 20)

See accompanying notes to the consolidated financial statements.

Naveen Dargan
Director, Baytex Energy Corp.

Jennifer A. Maki
Director, Baytex Energy Corp.

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

Years Ended December 31	Notes	2020	2019
Revenue, net of royalties			
Petroleum and natural gas sales	14	$ **975,477**	$ 1,805,919
Royalties		**(163,735)**	(320,241)
		811,742	1,485,678
Expenses			
Operating		**331,345**	397,716
Transportation		**28,437**	43,942
Blending and other		**48,381**	68,795
General and administrative		**34,268**	45,469
Exploration and evaluation	5	**14,011**	11,764
Depletion and depreciation		**486,380**	731,686
Impairments	5, 6	**2,360,220**	187,822
Share-based compensation	12	**9,469**	15,894
Financing and interest	16	**125,441**	125,865
Financial derivatives (gain) loss	18	**(29,336)**	7,197
Foreign exchange loss (gain)	17	**8,688**	(61,787)
Gain on dispositions		**(901)**	(2,238)
Other income		**(5,304)**	(7,526)
		3,411,099	1,564,599
Net loss before income taxes		**(2,599,357)**	(78,921)
Income tax expense (recovery)	15		
Current income tax expense		**574**	2,093
Deferred income tax recovery		**(160,967)**	(68,555)
		(160,393)	(66,462)
Net loss		$ **(2,438,964)**	$ (12,459)
Other comprehensive income (loss)			
Foreign currency translation adjustment		**62,752**	(111,650)
Comprehensive loss		$ **(2,376,212)**	$ (124,109)
Net loss per common share	13		
Basic		$ **(4.35)**	$ (0.02)
Diluted		$ **(4.35)**	$ (0.02)
Weighted average common shares	13		
Basic		**560,657**	557,048
Diluted		**560,657**	557,048

See accompanying notes to the consolidated financial statements.

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

	Notes	Shareholders' capital	Contributed surplus	Accumulated other comprehensive income	Deficit	**Total equity**
Balance at December 31, 2018		$ 5,701,516	$ 19,137	$ 667,874	$ (3,333,103)	**$ 3,055,424**
Vesting of share awards	11	17,319	(17,319)	—	—	**—**
Share-based compensation	12	—	15,894	—	—	**15,894**
Comprehensive loss		—	—	(111,650)	(12,459)	**(124,109)**
Balance at December 31, 2019		$ 5,718,835	$ 17,712	$ 556,224	$ (3,345,562)	**$ 2,947,209**
Vesting of share awards	11	10,583	(10,583)	—	—	**—**
Share-based compensation	12	—	7,216	—	—	**7,216**
Comprehensive income (loss)		—	—	62,752	(2,438,964)	**(2,376,212)**
Balance at December 31, 2020		$ 5,729,418	$ 14,345	$ 618,976	$ (5,784,526)	**$ 578,213**

See accompanying notes to the consolidated financial statements.

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

Years Ended December 31	Notes	2020	2019
CASH PROVIDED BY (USED IN):			
Operating activities			
Net loss		**$ (2,438,964)**	$ (12,459)
Adjustments for:			
Share-based compensation	12	**7,216**	15,894
Unrealized foreign exchange loss (gain)	17	**9,232**	(62,753)
Exploration and evaluation	5	**14,011**	11,764
Depletion and depreciation		**486,380**	731,686
Impairments	5, 6	**2,360,220**	187,822
Non-cash financing, accretion and early redemption expense	16	**18,907**	18,448
Non-cash other income	10	**(2,128)**	—
Unrealized financial derivatives loss	18	**18,500**	82,817
Gain on dispositions		**(901)**	(2,238)
Deferred income tax recovery	15	**(160,967)**	(68,555)
Asset retirement obligations settled	10	**(7,168)**	(15,417)
Change in non-cash working capital	19	**48,758**	(52,070)
		353,096	834,939
Financing activities			
Increase (decrease) in credit facilities	8	**143,248**	(7,775)
Payments on lease obligations	7	**(5,925)**	(5,956)
Net proceeds from issuance of long-term notes	9	**652,150**	—
Redemption of long-term notes	9	**(833,672)**	(198,128)
		(44,199)	(211,859)
Investing activities			
Additions to exploration and evaluation assets	5	**(4,490)**	(2,948)
Additions to oil and gas properties	6	**(275,850)**	(549,343)
Additions to other plant and equipment		**(2,280)**	(552)
Property acquisitions		**—**	(3,667)
Proceeds from dispositions		**182**	1,487
Change in non-cash working capital	19	**(32,031)**	(62,485)
		(314,469)	(617,508)
Change in cash		**(5,572)**	5,572
Cash, beginning of year		**5,572**	—
Cash, end of year		**$ —**	$ 5,572
Supplementary information			
Interest paid		**$ 102,358**	$ 112,241
Income taxes paid		**$ 1,155**	$ 1,160

See accompanying notes to the consolidated financial statements.

1. REPORTING ENTITY

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

2. BASIS OF PRESENTATION

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

The consolidated financial statements were approved by the Board of Directors of Baytex on February 24, 2021.

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

Current Environment and Estimation Uncertainty

Management makes judgements and assumptions about the future in deriving estimates used in preparation of these consolidated financial statements in accordance with IFRS. Sources of estimation uncertainty include estimates used to determine economically recoverable oil, natural gas, and natural gas liquids reserves, the recoverable amount of long-lived assets or cash generating units, the provision for asset retirement obligations and the provision for income taxes and the related deferred tax assets and liabilities.

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 (collectively, "OPEC+") 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 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.

These factors have impacted our results for the year ended December 31, 2020. We recorded impairments of $2.4 billion for the year ended December 31, 2020 which included amounts related to our exploration and evaluation assets (note 5) and oil and gas properties (note 6). These impairments were a result of a sharp drop in forecasted prices for the commodities we produce. In the current environment, assumptions and estimates regarding future commodity prices, the amount of economically recoverable reserves, exchange rates, and interest rates are subject to greater variability than normal. Actual results may differ from these estimates as the effect of future events cannot be determined with certainty.

We took action to protect our financial liquidity in response to the volatility in commodity prices and instability in the global economy. We reduced our capital expenditures during 2020 and reduced production of oil and natural gas when commodity prices did not support economic production. As a result of these actions we maintained $367.2 million of availability on our credit facilities at December 31, 2020.

Measurement Uncertainty and Judgments

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 natural gas liquids ("NGL") reserves in the calculation of depletion, evaluating the recoverability of deferred income tax assets 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 valuation of deferred income tax assets, 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

Tax regulations and legislation in the various jurisdictions in which the Company and its subsidiaries operate are subject to change and there are differing interpretations requiring management judgment. Deferred tax assets are recognized when it is considered probable that deductible temporary differences will be recovered in future periods, which requires management judgment. Deferred tax liabilities are recognized when it is considered probable that temporary differences will be payable to tax authorities in future periods, which requires management judgment. Income tax filings are subject to audit and re-assessment and changes in facts, circumstances and interpretations of the standards may result in a material change to the Company's provision for income taxes. Estimates of future income taxes are subject to measurement uncertainty.

3. SIGNIFICANT ACCOUNTING POLICIES

Changes in Significant Accounting Policies

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 should the criteria of the optional asset concentration test within these amendments be met.

Significant Accounting Policies

Consolidation

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

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

Business Combinations

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

Revenue Recognition

Revenue from the sale of light oil and condensate, heavy oil, natural gas liquids, and natural gas is recognized based on the consideration specified in contracts with customers. Baytex recognizes revenue by unit of production and when control of the product transfers to the customer and collection is reasonably assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon.

The nature of the Company's performance obligations, including roles of third parties and partners, are evaluated to determine if the Company acts as a principal. Baytex recognizes revenue on a gross basis when it acts as the principal and has primary responsibility for the transaction. Revenue is recognized on a net basis when Baytex acts in the capacity of an agent rather than as a principal.

The transaction price for variable price contracts in the Canadian and U.S. operating segments is based on a representative commodity price index, and may include adjustments for quality, location, delivery method, or other factors depending on the agreed upon terms of the contract. The amount of revenue recorded can vary depending on the grade, quality and quantities of oil or natural gas transferred to customers. Market conditions, which impact the Company's ability to negotiate certain components of the transaction price, can also cause the amount of revenue recorded to fluctuate from period to period.

Tariffs, tolls and fees charged to other entities for the use of pipelines and facilities owned by Baytex are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

Exploration and Evaluation Assets

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

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

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

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

Oil and Gas Properties

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

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

Depletion and Depreciation

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

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

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

The expected lives of other plant and equipment are reviewed on an annual basis and, if necessary, changes in expected useful lives are accounted for prospectively.

Impairment and Impairment Reversals

<u>Non-financial assets</u>

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

When reviewing for indicators of impairment and impairment reversal, and testing for impairment or impairment reversal when indicators have been identified, assets are grouped together at a CGU level. The recoverable amount of an asset or CGU is the higher of its FVLCD and its VIU. The determination of recoverable amount includes estimates of proved and probable oil and gas reserves and the associated cash flows. Factors that impact these cash flows includes CGU production volumes, royalty obligations, operating costs, capital costs, forecast commodity prices, along with inflation and discount rates used to estimate present value. FVLCD is determined as the amount that would be obtained from the sale of an asset or CGU in an arm's length transaction between willing parties. In determining FVLCD, recent market transactions are considered if available. In the absence of such transactions, an appropriate valuation model is used. VIU is assessed using the present value of the estimated future cash flows of the asset or CGU. The estimated future cash flows are adjusted for risks specific to the asset or CGU and are discounted using a discount rate that reflects current market assessments of the time value of money.

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

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

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

Leases

A contract is, or contains, a lease if the contract conveys the right to control the use of an identified asset for a period of time in exchange for consideration. A lease obligation and corresponding right-of-use asset ("lease asset") are recognized at the commencement of the lease. The present value of the lease obligation is based on the future lease payments and is discounted using the Company's incremental borrowing rate when the rate implicit in the lease is not readily available. The Company uses a single discount rate for a portfolio of leases with similar characteristics. The lease asset is recognized at the amount of the lease obligation, adjusted for lease incentives received and initial direct costs, on commencement of the lease. Depreciation is recognized on the lease asset over the shorter of the estimated useful life of the asset or the lease term.

Lease payments are allocated between the liability and interest expense. Interest expense is recognized on the lease obligations using the effective interest rate method and payments are applied against the lease obligation.

Management judgement is required to determine the discount rate used to calculate the present value of the lease obligation. The carrying amounts of the lease assets, lease obligations, and the resulting interest and depletion and depreciation expense are based on the implicit interest rate within the lease arrangement or, if this information is unavailable, the incremental borrowing rate. Incremental borrowing rates are based on judgments including economic environment, term, and the underlying risk inherent to the asset.

Asset Retirement Obligations

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

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

Foreign Currency Translation

Foreign transactions

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

Foreign operations

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

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

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

Financial Instruments

Financial assets are initially classified into three categories: measured at amortized cost; fair value through other comprehensive income (“FVOCI”); or fair value through profit or loss (“FVTPL”). Financial assets are categorized based on the Company’s objective for the asset and the contractual cash flows. A financial asset is classified as amortized cost if the asset is held with the objective to collect contractual cash flows that are solely payments of principal and interest on principal amounts outstanding. A financial asset is classified as FVOCI if the asset is held with the objective to both collect contractual cash flows and sell the financial asset. All other financial assets are measured at FVTPL. Financial assets are assessed for impairment using an expected credit loss model. Trade and other receivables are classified and measured at amortized cost.

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

Financial Instrument	**Classification**
Cash and cash equivalents	Amortized cost
Trade and other receivables	Amortized cost
Financial derivatives	Fair value through profit or loss
Trade and other payables	Amortized cost
Credit facilities	Amortized cost
Long-term notes	Amortized cost
Lease obligations	Amortized cost

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

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

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

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

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

Fair Value of Financial Instruments

Baytex classifies the fair value of financial instruments according to the following hierarchy based on the amount of observable inputs used to value the instruments:

- Level 1: Values based on unadjusted quoted prices in active markets that are accessible at the measurement date for identical assets or liabilities.
- Level 2: Values based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability.
- Level 3: Values based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement.

Income Taxes

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

Current income taxes for the current and prior periods are measured at the amount expected to be recoverable from or payable to the taxation authorities based on the income tax rates enacted at the end of the reporting period. The Company recognizes the financial statement impact of a tax filing position when it is probable that the position will be sustained upon audit. The liability is measured based on an assessment of possible outcomes and their associated probabilities.

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

Share-based Compensation Plans

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

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

The Company has a cash-settled incentive award plan (the "Incentive Award Plan") pursuant to which incentive awards may be granted to officers and employees of the Company and its subsidiaries. Each incentive award entitles the holder to receive a cash payment equal to the value of one Baytex common share at the time of vesting. The incentive awards vest in equal tranches on the first, second and third anniversaries of the grant date. The cumulative expense is recognized at fair value at each period end and is included in trade and other payables.

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4. SEGMENTED FINANCIAL INFORMATION

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

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

	Canada		U.S.		Corporate		Consolidated	
Years Ended December 31	**2020**	2019	**2020**	2019	**2020**	2019	**2020**	2019
Revenue, net of royalties								
Petroleum and natural gas sales	**$ 571,741**	$ 1,077,724	**$ 403,736**	$ 728,195	**$ —**	$ —	**$ 975,477**	$ 1,805,919
Royalties	**(46,064)**	(107,467)	**(117,671)**	(212,774)	**—**	—	**(163,735)**	(320,241)
	525,677	970,257	**286,065**	515,421	**—**	—	**811,742**	1,485,678
Expenses								
Operating	**247,050**	298,303	**84,295**	99,413	**—**	—	**331,345**	397,716
Transportation	**28,437**	43,942	**—**	—	**—**	—	**28,437**	43,942
Blending and other	**48,381**	68,795	**—**	—	**—**	—	**48,381**	68,795
General and administrative	**—**	—	**—**	—	**34,268**	45,469	**34,268**	45,469
Exploration and evaluation	**14,011**	11,764	**—**	—	**—**	—	**14,011**	11,764
Depletion and depreciation	**309,420**	463,501	**169,439**	261,766	**7,521**	6,419	**486,380**	731,686
Impairment	**1,737,000**	187,822	**623,220**	—	**—**	—	**2,360,220**	187,822
Share-based compensation	**—**	—	**—**	—	**9,469**	15,894	**9,469**	15,894
Financing and interest	**—**	—	**—**	—	**125,441**	125,865	**125,441**	125,865
Financial derivatives (gain) loss	**—**	—	**—**	—	**(29,336)**	7,197	**(29,336)**	7,197
Foreign exchange loss (gain)	**—**	—	**—**	—	**8,688**	(61,787)	**8,688**	(61,787)
Gain on dispositions	**(901)**	(2,238)	**—**	—	**—**	—	**(901)**	(2,238)
Other income	**(2,128)**	—	**—**	—	**(3,176)**	(7,526)	**(5,304)**	(7,526)
	2,381,270	1,071,889	**876,954**	361,179	**152,875**	131,531	**3,411,099**	1,564,599
Net income (loss) before income taxes	**(1,855,593)**	(101,632)	**(590,889)**	154,242	**(152,875)**	(131,531)	**(2,599,357)**	(78,921)
Income tax expense (recovery)								
Current income tax expense	**469**	101	**105**	1,992	**—**	—	**574**	2,093
Deferred income tax (recovery) expense	**(77,201)**	(32,942)	**(57,199)**	10,055	**(26,567)**	(45,668)	**(160,967)**	(68,555)
	(76,732)	(32,841)	**(57,094)**	12,047	**(26,567)**	(45,668)	**(160,393)**	(66,462)
Net income (loss)	**$(1,778,861)**	$ (68,791)	**$ (533,795)**	$ 142,195	**$ (126,308)**	$ (85,863)	**$(2,438,964)**	$ (12,459)
Total oil and natural gas capital expenditures (1)	**$ 174,770**	$ 376,543	**$ 105,388**	$ 177,928	**$ —**	$ —	**$ 280,158**	$ 554,471

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

As at	**December 31, 2020**	December 31, 2019
Canadian assets	**$ 1,646,412**	$ 3,484,123
U.S. assets	**1,737,533**	2,403,310
Corporate assets	**24,151**	26,650
Total consolidated assets	**$ 3,408,096**	$ 5,914,083

5. EXPLORATION AND EVALUATION ASSETS

	December 31, 2020	December 31, 2019
Balance, beginning of year	**$ 320,210**	$ 358,935
Capital expenditures	**4,490**	2,948
Property acquisitions	**—**	1,523
Divestitures	**—**	(443)
Impairment	**(113,058)**	(7,822)
Property swaps	**468**	417
Exploration and evaluation expense	**(14,011)**	(11,764)
Transfers to oil and gas properties (note 6)	**(8,585)**	(16,204)
Foreign currency translation	**2,351**	(7,380)
Balance, end of year	**$ 191,865**	$ 320,210

At March 31, 2020, the Company identified indicators of impairment for the exploration and evaluation assets within each of its six CGUs. The estimated recoverable amount was below the carrying value of the exploration and evaluation assets in the Conventional, Peace River, Lloydminster, Viking and Eagle Ford CGUs and an impairment of $127.9 million was recorded as at March 31, 2020. The recoverable amount of each CGU was based on its FVLCD and was estimated with reference to arm's length transaction in comparable locations and the discounted cash flows associated with the Company's future development plans. The following table indicates the impairment booked for each CGU at March 31, 2020.

	Impairment at March 31, 2020
Conventional CGU	$ 4,000
Peace River CGU	20,000
Lloydminster CGU	42,000
Viking CGU	13,000
Eagle Ford CGU	48,861
	$ 127,861

At December 31, 2020, the Company estimated the recoverable amount of the exploration and evaluation assets within each of its six CGUs due to the ongoing volatility in future oil and natural gas prices. The recoverable amount supported the carrying amount for the Conventional, Peace River, Lloydminster, and Duvernay CGUs and no impairment or impairment reversal was recorded. The recoverable amount for the Viking and Eagle Ford CGUs exceeded their carrying amounts which resulted in an impairment reversal of $14.8 million at December 31, 2020. The recoverable amount of each CGU was based on its FVLCD and was estimated with reference to arm's length transaction in comparable locations and the discounted cash flows associated with the Company's future development plans. The following table indicates the impairment reversal booked for the Viking and Eagle Ford CGUs at December 31, 2020.

	Impairment reversal at December 31, 2020
Viking CGU	$ 2,000
Eagle Ford CGU	12,803
	$ 14,803

At December 31, 2019 the Company identified indicators of impairment for the exploration and evaluation assets within the Peace River CGU. The estimated recoverable amount was below the carrying value of the exploration and evaluation assets in the Peace River CGU and an impairment $7.8 million was recorded as at December 31, 2019. There were no indicators of impairment for exploration and evaluation assets in the remaining CGUs at December 31, 2019.

6. OIL AND GAS PROPERTIES

		Cost		Accumulated depletion		Net book value
Balance, December 31, 2018	**$**	**10,744,533**	**$**	**(4,926,644)**	**$**	**5,817,889**
Capital expenditures		549,343		—		549,343
Property acquisitions		2,636		—		2,636
Transfers from exploration and evaluation assets (note 5)		16,204		—		16,204
Change in asset retirement obligations (note 10)		23,894		—		23,894
Divestitures		(2,069)		1,690		(379)
Property swaps		1,773		—		1,773
Impairment		—		(180,000)		(180,000)
Foreign currency translation		(208,017)		89,813		(118,204)
Depletion		—		(725,267)		(725,267)
Balance, December 31, 2019	**$**	**11,128,297**	**$**	**(5,740,408)**	**$**	**5,387,889**
Capital expenditures		275,850		—		275,850
Transfers from exploration and evaluation assets (note 5)		8,585		—		8,585
Change in asset retirement obligations (note 10)		94,994		—		94,994
Property swaps		(1,190)		178		(1,012)
Impairments		—		(2,247,162)		(2,247,162)
Foreign currency translation		(82,860)		120,123		37,263
Depletion		—		(478,859)		(478,859)
Balance, December 31, 2020	**$**	**11,423,676**	**$**	**(8,346,128)**	**$**	**3,077,548**

Baytex recorded total impairments related to oil and gas properties of $2.2 billion for the year ended December 31, 2020 and $180.0 million for the year ended December 31, 2019.

At March 31, 2020, the Company identified indicators of impairment for each of its six CGUs due to a significant decline in forecasted commodity prices. The recoverable amount was not sufficient to support the carrying amount which resulted in an impairment of $2.6 billion recorded at March 31, 2020. The recoverable amount of each CGU was based on its FVLCD which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2019 and was adjusted for operations between December 31, 2019 and March 31, 2020. The after-tax discount rates applied to the cash flows were between 8% and 14%.

The recoverable amount of the Company's CGUs were calculated at March 31, 2020 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%.

	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 demonstrates the sensitivity of the estimated recoverable amount of the Company's CGUs 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 Company estimated the recoverable amount of each of its six CGUs due to the volatility in commodity prices during the year and a reduction in future development costs per well for the Viking and Eagle Ford CGUs. The recoverable amount supported the carrying amount for the Conventional, Peace River, Lloydminster, and Duvernay CGUs and no impairment or impairment reversal was recorded. The recoverable amount for the Viking and Eagle Ford CGUs exceeded their carrying amounts which resulted in an impairment reversal of $341.3 million recorded at December 31, 2020. The recoverable amount for each CGU was based on its FVLCD which was estimated using a discounted cash flow model of proved plus probable cash flows from an independent reserve report prepared as at December 31, 2020. The after-tax discount rates applied to the cash flows were between 10% and 17%.

The recoverable amount of the Company's CGUs were calculated at December 31, 2020 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%.

	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 demonstrates the sensitivity of the estimated recoverable amount of the Company's CGUs 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

At December 31, 2019, the Company identified indicators of impairment for its Peace River CGU due to a sustained decline in Canadian heavy oil prices and a reduction in planned exploration and development expenditures related to thermal properties in the Peace River CGU. The recoverable amount of the Peace River CGU was based on its VIU which was estimated using a discounted cash flow model using proved plus probable cash flows from an independent reserve report prepared as at December 31, 2019 and an after-tax discount rate of 11%. The recoverable amount was not sufficient to support the carrying amount of the CGU which resulted in an impairment of $180.0 million recorded as at December 31, 2019. There were no indicators of impairment or impairment reversal for the remaining CGUs at December 31, 2019.

7. LEASES

Lease Assets

Baytex had the following right-of-use assets at December 31, 2020.

		Office Leases		Field Equipment		Vehicles and Other		Total
Balance, January 1, 2019 [(1)]	**$**	**14,775**	**$**	**2,254**	**$**	**969**	**$**	**17,998**
Additions		—		1,668		159		1,827
Modifications		(6)		4		19		17
Depreciation		(4,904)		(837)		(482)		(6,223)
Balance, December 31, 2019	**$**	**9,865**	**$**	**3,089**	**$**	**665**	**$**	**13,619**
Additions		20		962		203		1,185
Modifications		1,846		80		7		1,933
Depreciation		(3,799)		(1,381)		(459)		(5,639)
Balance, December 31, 2020	**$**	**7,932**	**$**	**2,750**	**$**	**416**	**$**	**11,098**

(1) The Company adopted IFRS 16 Leases on January 1, 2019 using the modified retrospective approach.

Lease Obligations

Baytex had the following future commitments associated with its lease obligations at December 31, 2020.

		December 31, 2020		December 31, 2019
Less than 1 year	**$**	**4,504**	$	6,216
1 - 3 years		**4,302**		7,748
3 - 5 years		**3,044**		604
After 5 years		**—**		—
Total lease payments	**$**	**11,850**	$	14,568
Amounts representing interest over the term of the lease		**(774)**		(685)
Present value of net lease payments	**$**	**11,076**	$	13,883
Less current portion of lease obligations		**4,289**		5,798
Non-current portion of lease obligations	**$**	**6,787**	$	8,085

The Company recorded interest expense related to its lease obligations of $0.4 million and recorded lease payments of $5.9 million for the year ended December 31, 2020 (December 31, 2019 - $0.6 million and 6.0 million, respectively).

8. CREDIT FACILITIES

		December 31, 2020		December 31, 2019
Credit facilities - U.S. dollar denominated [(1)]	**$**	**140,815**	$	206,144
Credit facilities - Canadian dollar denominated		**510,358**		300,327
Credit facilities - principal [(2)]	**$**	**651,173**	$	506,471
Unamortized debt issuance costs		**(1,952)**		(1,059)
Credit facilities	**$**	**649,221**	$	505,412

(1) U.S. dollar denominated credit facilities balance was US$110.4 million as at December 31, 2020 (December 31, 2019 - US$159.0 million).
(2) The increase in the principal amount of the credit facilities outstanding from December 31, 2019 to December 31, 2020 is the result of net draws of $145.0 million and a decrease in the reported amount of U.S. denominated debt of $0.3 million due to foreign exchange.

Baytex has US$575 million of revolving credit facilities (the "Revolving Facilities") and a $300 million non-revolving secured term loan (the "Term Loan") (collectively the "Credit Facilities"). On March 3, 2020, Baytex amended its Credit Facilities to extend maturity from April 2, 2021 to April 2, 2024. These facilities 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.

The extendible secured Revolving Facilities are comprised of a US$50 million operating loan and a US$325 million syndicated revolving loan for Baytex and a US$200 million syndicated revolving loan for Baytex's wholly-owned subsidiary, Baytex Energy USA, Inc. The $300 million Term Loan is secured by the assets of Baytex's wholly-owned subsidiary, Baytex Energy Limited Partnership.

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 Baytex's request. Advances (including letters of credit) under the Credit Facilities can be drawn in either Canadian or U.S. funds and bear interest at the bank's prime lending rate, bankers' acceptance discount rates or London Interbank Offered Rates ("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.

At December 31, 2020, Baytex had $15.0 million of outstanding letters of credit (December 31, 2019 - $15.2 million) under the Credit Facilities.

At December 31, 2020, Baytex was in compliance with all of the covenants contained in the Credit Facilities and is forecasting compliance with these covenants based on current forward prices. The following table summarizes the financial covenants applicable to the Revolving Facilities and Baytex's compliance therewith as 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 or 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 expense, 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.

9. LONG-TERM NOTES

	December 31, 2020	December 31, 2019
5.125% notes (US$400,000 – principal) due June 1, 2021	**$ —**	$ 518,600
6.625% notes ($300,000 – principal) due July 19, 2022	**—**	300,000
5.625% notes (US$400,000 – principal) due June 1, 2024	**510,200**	518,600
8.75% notes (US$500,000 – principal) due April 1, 2027	**637,750**	—
Total long-term notes - principal (1)	**$ 1,147,950**	$ 1,337,200
Unamortized debt issuance costs	**(15,082)**	(9,025)
Total long-term notes - net of unamortized debt issuance costs	**$ 1,132,868**	$ 1,328,175

(1) The decrease in the principal amount of long-term notes outstanding from December 31, 2019 to December 31, 2020 is the result of principal repayments of $830.4 million, the issuance of $664.7 million aggregate principal amount and changes in the reported amount of U.S. denominated debt of $23.6 million.

On February 5, 2020, Baytex 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 Baytex's 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, Baytex 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 principal payment was $530.4 million.

On March 5, 2020, Baytex 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 principal payment was $300.0 million plus early redemption expense of $3.3 million.

The long-term notes do not contain any significant financial maintenance covenants but do contain a debt incurrence covenant that restricts the Company's ability to raise additional debt beyond the existing Credit Facilities and long-term notes.

10. ASSET RETIREMENT OBLIGATIONS

	December 31, 2020	December 31, 2019
Balance, beginning of year	**$ 667,974**	$ 646,898
Liabilities incurred	**15,189**	21,748
Liabilities settled	**(7,168)**	(15,417)
Liabilities acquired from property acquisitions	**—**	1,648
Liabilities divested	**(721)**	(1,331)
Property swaps	**(525)**	792
Accretion (note 16)	**8,978**	13,713
Government grants (1)	**(2,128)**	—
Change in estimate (2)	**(12,771)**	19,632
Changes in discount rates and inflation rates	**92,576**	(17,486)
Foreign currency translation	**(1,021)**	(2,223)
Balance, end of year	**$ 760,383**	$ 667,974
Less current portion of asset retirement obligations	**11,820**	11,579
Non-current portion of asset retirement obligations	**$ 748,563**	$ 656,395

(1) Baytex received $2.1 million of government grants from the Governments of Alberta and Saskatchewan. The grants were used to abandon and reclaim well sites which reduced our assets retirement obligations and was included in other income.
(2) Changes in the estimated costs, the timing of abandonment and reclamation and the status of wells are factors resulting in a change in estimate.

At December 31, 2020, the undiscounted amount of estimated cash flows required to settle the asset retirement obligations is $721.0 million (December 31, 2019 - $714.8 million). The discounted amount of estimated cash flow required to settle the asset retirement obligations at December 31, 2020, calculated using an estimated inflation rate of 1.5% (December 31, 2019 - 1.4%) and a risk free discount rate of 1.2% (December 31, 2019 - 1.8%), is $760.4 million (December 31, 2019 - $668.0 million). These costs are expected to be incurred over the next 60 years.

11. SHAREHOLDERS' CAPITAL

The authorized capital of Baytex consists of an unlimited number of common shares without nominal or par value and 10.0 million preferred shares without nominal or par value, issuable in series. Baytex establishes the rights and terms of the preferred shares upon issuance. As at December 31, 2020, no preferred shares have been issued by the Company and all common shares issued were fully paid.

The holders of common shares may receive dividends as declared from time to time and are entitled to one vote per share at any meetings of the holders of common shares. All common shares rank equally with regard to the Company's net assets in the event the Company is wound-up or terminated.

	Number of Common Shares *(000s)*	Amount
Balance, December 31, 2018	**554,060**	**$ 5,701,516**
Vesting of share awards	4,245	17,319
Balance, December 31, 2019	**558,305**	**$ 5,718,835**
Vesting of share awards	2,922	10,583
Balance, December 31, 2020	**561,227**	**$ 5,729,418**

12. SHARE-BASED COMPENSATION PLAN

The Company recorded compensation expense related to the share awards of $9.5 million for the year ended December 31, 2020 ($15.9 million for the year ended December 31, 2019) which includes $2.3 million of cash compensation expense related to the incentive award plan and the associated equity total return swaps.

Share Award Plans

Baytex has a share award plan pursuant to which it issues restricted and performance awards. A restricted award entitles the holder of each award to receive one common share of Baytex at the time of vesting. A performance award entitles the holder of each award to receive between zero and two common shares on vesting; the number of common shares issued is determined by a multiplier. The multiplier, which ranges between zero and two, is calculated based on a number of factors determined and approved by the Board of Directors on an annual basis. The restricted awards and performance awards vest in equal tranches on the first, second and third anniversaries of the grant date.

The weighted average fair value of share awards granted during the year ended December 31, 2020 was $1.48 per restricted and performance award (December 31, 2019 - $2.63).

The number of share awards outstanding is detailed below:

(000s)	Number of restricted awards	Number of performance awards[(1)]	Total number of share awards
Balance, December 31, 2018	**3,243**	**3,273**	**6,516**
Granted	3,184	3,245	6,429
Vested and converted to common shares	(2,081)	(2,164)	(4,245)
Forfeited	(545)	(1,219)	(1,764)
Balance, December 31, 2019	**3,801**	**3,135**	**6,936**
Granted	2,239	3,253	5,492
Vested and converted to common shares	(1,730)	(1,192)	(2,922)
Forfeited	(188)	(1,108)	(1,296)
Balance, December 31, 2020	**4,122**	**4,088**	**8,210**

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

Incentive Award Plan

Baytex has a cash-settled incentive award plan (the "Incentive Award" plan) whereby the holder of each incentive award is entitled to receive a cash payment equal to the value of one Baytex common share at the time of vesting. The incentive awards vest in equal tranches on the first, second and third anniversaries of the grant date. The cumulative expense is recognized at fair value at each period end and is included in trade and other payables.

The Company uses equity total return swaps ("Equity TRS") on the equivalent number of Baytex common shares in order to fix the aggregate cost of the Incentive Award plan at the fair value determined on the grant date. The carrying value of the financial derivatives includes the fair value of the Equity TRS which was a liability of $1.1 million on December 31, 2020.

During the year ended December 31, 2020, Baytex granted 2.9 million awards under the Incentive Award plan at a fair value of $1.50 per award.

Share Options

Baytex assumed share option plans pursuant to a business combination in 2018. No new grants will be made under the option plans. At December 31, 2020, 0.3 million share options were outstanding with a weighted average remaining life of 0.3 years and a weighted average exercise price of $5.40 (December 31, 2019 - 2.5 million options with a weighted average exercise price of $6.83).

13. NET INCOME (LOSS) PER SHARE

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

	Years Ended December 31					
	2020			2019		
	Net loss	**Weighted average common shares (000's)**	**Net loss per share**	Net loss	Weighted average common shares (000's)	Net loss per share
Net loss - basic	**$ (2,438,964)**	**560,657**	**$ (4.35)**	$ (12,459)	557,048	$ (0.02)
Dilutive effect of share awards	**—**	**—**	**—**	—	—	—
Dilutive effect of share options	**—**	**—**	**—**	—	—	—
Net loss - diluted	**$ (2,438,964)**	**560,657**	**$ (4.35)**	$ (12,459)	557,048	$ (0.02)

For the years ended December 31, 2020 and December 31, 2019, all share awards and share options were excluded from the calculation of diluted earnings per share as their effect was anti-dilutive given the Company recorded a net loss.

14. PETROLEUM AND NATURAL GAS SALES

The Company's petroleum and natural gas sales from contracts with customers for each reportable segment is set forth in the following table.

	Years Ended December 31					
	2020			2019		
	Canada	**U.S.**	**Total**	Canada	U.S.	Total
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
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

Included in accounts receivable at December 31, 2020 is $81.3 million (December 31, 2019 - $138.0 million) of accrued petroleum and natural gas sales related to deliveries for periods ended prior to the reporting date.

15. INCOME TAXES

The provision for income taxes has been computed as follows:

	Years Ended December 31	
	2020	2019
Net loss before income taxes	**$ (2,599,357)**	$ (78,921)
Expected income taxes at the statutory rate of 25.42%(1) (2019 – 26.72%)	**(660,757)**	(21,088)
(Increase) decrease in income tax recovery resulting from:		
Share-based compensation	**1,834**	4,247
Effect of foreign exchange	**1,017**	(8,155)
Effect of change in income tax rates	**10,969**	(6,098)
Effect of rate adjustments for foreign jurisdictions	**22,375**	(27,785)
Effect of change in deferred tax benefit not recognized	**444,117**	(7,563)
Effect of U.S. tax change	**19,807**	—
Adjustments and assessments	**245**	(20)
Income tax recovery	**$ (160,393)**	$ (66,462)

(1) On October 20, 2020 the Alberta government enacted legislation to decrease the corporate income tax rate from 10% to 8% effective July 1, 2020.

At December 31, 2020, a deferred tax asset of $469.7 million remains unrecognized due to uncertainty surrounding future commodity prices and future capital gains (December 31, 2019 - $28.0 million). These deferred income tax assets relate to deductible temporary differences of $854.2 million, capital losses of $237.9 million and non-capital losses of $1,015.2 million, which expire from 2034 to 2040.

In June 2016, certain indirect subsidiary entities received reassessments from the Canada Revenue Agency (the "CRA") that denied $591 million of non-capital loss deductions that relate to the calculation of income taxes for the years 2011 through 2015. In September 2016, Baytex 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 the Company's file in July 2018. Baytex remains confident that the original tax filings are correct and intends to defend those tax filings through the appeals process.

On April 7, 2020, the U.S. Department of the Treasury and the IRS published final regulations addressing "anti-hybrid" rules under section 267A of the U.S. tax code and thus became substantially enacted. Pursuant to these regulations, the Company is no longer entitled to certain tax benefits previously recognized during 2019. Accordingly, a charge against deferred income taxes in the amount of $19.8 million was recorded in 2020.

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

As at	January 1, 2020	Recognized in Net Income	Foreign Currency Translation Adjustment	**December 31, 2020**
Taxable temporary differences:				
Petroleum and natural gas properties	$ (881,994)	$ 378,321	$ 1,048	**$ (502,625)**
Financial derivatives	—	—	—	**—**
Other	(2,403)	(18,839)	(1,135)	**(22,377)**
Deductible temporary differences:				
Asset retirement obligations	164,523	23,432	(115)	**187,840**
Financial derivatives	802	4,608	—	**5,410**
Non-capital losses	386,717	(141,468)	(3,735)	**241,514**
Other	97,047	(85,087)	(8,255)	**3,705**
Net deferred income tax liability [1]	$ (235,308)	$ 160,967	$ (12,192)	**$ (86,533)**

(1) Non-capital loss carry-forwards at December 31, 2020 totaled $2,165.2 million and expire from 2034 to 2040.

As at	January 1, 2019	Recognized in Net Loss	Foreign Currency Translation Adjustment	**December 31, 2019**
Taxable temporary differences:				
Petroleum and natural gas properties	$ (954,506)	$ 48,995	$ 23,517	**$ (881,994)**
Financial derivatives	(21,486)	21,486	—	**—**
Other	(3,045)	5,192	(4,550)	**(2,403)**
Deductible temporary differences:				
Asset retirement obligations	172,359	(7,364)	(472)	**164,523**
Financial derivatives	—	802	—	**802**
Non-capital losses	399,699	(1,460)	(11,522)	**386,717**
Finance costs	96,143	904	—	**97,047**
Net deferred income tax liability [1]	$ (310,836)	$ 68,555	$ 6,973	**$ (235,308)**

(1) Non-capital loss carry-forwards at December 31, 2019 totaled $1,714.6 million and expire from 2034 to 2039.

16. FINANCING AND INTEREST

	Years Ended December 31	
	2020	2019
Interest on credit facilities	**$ 15,256**	$ 20,376
Interest on long-term notes	**90,830**	86,431
Interest on lease obligations	**448**	610
Non-cash financing	**6,617**	4,735
Accretion of asset retirement obligations (note 10)	**8,978**	13,713
Early redemption expense (note 9)	**3,312**	—
Financing and interest	**$ 125,441**	$ 125,865

17. FOREIGN EXCHANGE

	Years Ended December 31	
	2020	2019
Unrealized foreign exchange loss - intercompany notes [(1)]	**$ 31,617**	$ —
Unrealized foreign exchange gain - long-term notes	**(22,385)**	(62,753)
Realized foreign exchange (gain) loss	**(544)**	966
Foreign exchange loss (gain)	**$ 8,688**	$ (61,787)

(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.

18. FINANCIAL INSTRUMENTS AND RISK MANAGEMENT

The Company's financial assets and liabilities are comprised of cash, trade and other receivables, trade and other payables, financial derivatives, credit facilities and long-term notes. The carrying value of cash, trade and other receivables and trade and other payables approximates their fair value due to the short period to maturity of these instruments. The fair value of the credit facilities is equal to the principal amount outstanding as the credit facilities bear interest at floating rates and credit spreads that are indicative of market rates. The fair value of the long-term notes is determined based on market prices. The fair value of financial derivatives is measured with reference to quoted market prices, estimated of future volatility and interest rates available at period end.

The carrying value and fair value of the Company's financial instruments carried on the consolidated statements of financial position are classified into the following categories:

	December 31, 2020		December 31, 2019		
	Carrying value	**Fair value**	Carrying value	Fair value	Fair Value Measurement Hierarchy
Financial Assets					
FVTPL					
Financial Derivatives	**$ 5,057**	**$ 5,057**	$ 5,433	$ 5,433	Level 2
Total	**$ 5,057**	**$ 5,057**	$ 5,433	$ 5,433	
Financial assets at amortized cost					
Cash	**$ —**	**$ —**	$ 5,572	$ 5,572	—
Trade and other receivables	**107,477**	**107,477**	173,762	173,762	—
Total	**$ 107,477**	**$ 107,477**	$ 179,334	$ 179,334	
Financial Liabilities					
FVTPL					
Financial Derivatives	**$ (26,792)**	**$ (26,792)**	$ (8,668)	$ (8,668)	Level 2
Total	**$ (26,792)**	**$ (26,792)**	$ (8,668)	$ (8,668)	
Financial liabilities at amortized cost					
Trade and other payables	**$ (155,955)**	**$ (155,955)**	$ (207,454)	$ (207,454)	—
Credit Facilities	**(649,221)**	**(651,173)**	(505,412)	(506,471)	—
Long-term notes	**(1,132,868)**	**(761,129)**	(1,328,175)	(1,290,817)	Level 1
Total	**$ (1,938,044)**	**$ (1,568,257)**	$ (2,041,041)	$ (2,004,742)	

There were no transfers between Level 1 and Level 2 in during the years ended December 31, 2020 or 2019.

Financial Risk

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

Market Risk

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

Foreign Currency Risk

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

To manage the impact of foreign exchange rate fluctuations, the Company may enter into agreements to fix the Canadian to U.S. dollar exchange rate. At December 31, 2020 and 2019, the Company did not have any currency derivative contracts outstanding.

A $0.01 increase or decrease in the CAD/USD foreign exchange rate on the revaluation of outstanding U.S. dollar denominated assets and liabilities, would impact net income or loss before income taxes by approximately $1.8 million.

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

	Assets		Liabilities	
	December 31, 2020	December 31, 2019	**December 31, 2020**	December 31, 2019
U.S. dollar denominated	**US$759,508**	US$8,733	**US$934,731**	US$841,961

Interest Rate Risk

The Company's interest rate risk arises from borrowing at floating rates under the Revolving Facilities and Term Loan (note 8). Based on the principal outstanding on the Credit Facilities, as at December 31, 2020, a change of 100 basis points in interest rates would have an impact on net income or loss before income taxes of approximately $6.5 million.

Commodity Price Risk

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

When assessing the potential impact of crude oil price changes on the crude oil financial derivative contracts outstanding as at December 31, 2020, a US$1.00/bbl change in the underlying benchmark crude oil prices would impact net income or loss before income taxes by approximately $18.9 million.

When assessing the potential impact of natural gas price changes on the financial derivative contracts outstanding as at December 31, 2020, a US$0.25 change in the underlying benchmark natural gas prices would impact net income or loss before income taxes by approximately $4.6 million.

Financial Derivative Contracts

Baytex had the following commodity financial derivative contracts outstanding 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 call, a bought put and a sold put. 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.

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

	Years Ended December 31	
	2020	2019
Realized financial derivatives gain	**$ (47,836)**	$ (75,620)
Unrealized financial derivatives loss	**18,500**	82,817
Financial derivatives (gain) loss	**$ (29,336)**	$ 7,197

Liquidity Risk

Liquidity risk is the risk that Baytex will encounter difficulty in meeting obligations associated with financial liabilities. Baytex manages its liquidity risk through cash and debt management. Such strategies include monitoring forecasted and actual cash flows from operating, financing and investing activities, available credit under existing banking arrangements, opportunities to issue additional common shares as well as reducing capital expenditures.

As at December 31, 2020, Baytex had available unused credit facilities in the amount of $367.2 million (December 31, 2019 - $523.8 million).

The timing of cash outflows relating to financial liabilities as at December 31, 2020 is outlined in the table below:

		Total		Less than 1 year		1-3 years		3-5 years		Beyond 5 years
Trade and other payables	$	**155,955**	$	155,955	$	—	$	—	$	—
Financial derivatives		**26,792**		26,792		—		—		—
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 obligations (2)		**11,850**		4,504		4,302		3,044		—
	$	**2,440,574**	**$**	**271,753**	**$**	**173,306**	**$**	**1,287,896**	**$**	**707,619**

(1) At December 31, 2019, the credit facilities were set to mature on April 2, 2021. On March 3, 2020, Baytex amended the credit facilities to extend maturity to April 2, 2024 which will automatically be extended to June 4, 2024 providing the Company 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. On February 5, 2020, Baytex issued US$500 million principal amount of 8.75% senior unsecured notes due 2027. On February 20, 2020 Baytex completed the redemption of the US$400 million principal amount of senior unsecured notes due 2021 and, on March 5, 2020, completed the redemption of $300 million principal amount of 6.625% senior unsecured notes due 2022 (note 9).

(3) Excludes interest on credit facilities as interest payments on credit facilities fluctuate based on amounts outstanding and the prevailing interest rate at the time of borrowing.

Credit Risk

Credit risk is the risk that a counterparty to a financial asset will default resulting in Baytex incurring a loss. As at December 31, 2020, the Company is exposed to credit risk with respect to its trade and other receivables and financial derivatives. Baytex manages these risks through the selection and monitoring of credit-worthy counterparties.

Most of the Company's trade and other receivables relate to petroleum and natural gas sales. Baytex reviews its exposure to individual entities on a regular basis and manages its credit risk by entering into sales contracts after reviewing the creditworthiness of the entity. Letters of credit or parental guarantees may be obtained prior to the commencement of business with certain counterparties. Credit risk may also arise from financial derivative instruments. The maximum exposure to credit risk is equal to the carrying value of the financial assets. The Company considers all financial assets that are not impaired or past due to be of good credit quality.

The majority of the Company's credit exposure on trade and other receivables at December 31, 2020 relates to accrued revenues. Accounts receivable from purchasers of the Company's petroleum and natural gas sales are typically collected on the 25th day of the month following production. Joint interest receivables are typically collected within one to three months following production. Included in trade and other receivables at December 31, 2020 is $81.3 million (December 31, 2019 - $138.0 million) of accrued petroleum and natural gas sales.

Should the Company determine that the ultimate collection of a receivable is in doubt, the carrying amount of trade and other receivables is reduced by adjusting the allowance for doubtful accounts and a charge to net income or loss. If the Company subsequently determines the accounts receivable is uncollectible, the receivable and allowance for doubtful accounts are adjusted accordingly. As at December 31, 2020, allowance for doubtful accounts was $2.0 million (December 31, 2019 - $1.6 million).

In determining whether amounts past due are collectible, the Company will assess the nature of the past due amounts as well as the credit worthiness and past payment history of the counterparty. As at December 31, 2020, accounts receivable that Baytex has deemed past due (more than 90 days) but not impaired was $1.6 million (December 31, 2019 - $2.7 million). Baytex has estimated the lifetime expected credit loss as at and for the year ended December 31, 2020 to be nominal.

The Company's trade and other receivables, net of the allowance for doubtful accounts, were aged as follows at December 31, 2020.

Trade and Other Receivables Aging		**December 31, 2020**		December 31, 2019
Current (less than 30 days)	**$**	**104,210**	$	169,500
31-60 days		**1,493**		1,199
61-90 days		**220**		342
Past due (more than 90 days)		**1,554**		2,721
	$	**107,477**	$	173,762

19. SUPPLEMENTAL INFORMATION

Changes in Non-Cash Working Capital Items

	Years Ended December 31	
	2020	2019
Trade and other receivables	**$ 66,285**	$ (62,198)
Trade and other payables	**(51,499)**	(50,660)
	$ 14,786	$ (112,858)
Changes in non-cash working capital related to:		
Operating activities	**$ 48,758**	$ (52,070)
Investing activities	**(32,031)**	(62,485)
Foreign currency translation on non-cash working capital	**(1,941)**	1,697
	$ 14,786	$ (112,858)

Income Statement Presentation

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

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

	Years Ended December 31	
	2020	2019
Operating	**$ 9,065**	$ 12,918
General and administrative	**22,802**	33,728
Total employee compensation costs	**$ 31,867**	$ 46,646

20. COMMITMENTS

Baytex has a number of financial obligations that are incurred in the ordinary course of business. These obligations are of a recurring nature and impact the Company's cash flow from operations in an ongoing manner. A significant portion of these obligations will be funded by adjusted funds flow. These obligations as of December 31, 2020, and the expected timing of funding of these obligations, are noted in the table below.

	Total	Less than 1 year	1-3 years	3-5 years	Beyond 5 years
Processing agreements	**$ 6,361**	836	1,320	474	3,731
Transportation agreements	**98,406**	16,698	40,351	24,903	16,454
Total	**$ 104,767**	$ 17,534	$ 41,671	$ 25,377	$ 20,185

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

21. RELATED PARTIES

Transactions with key management personnel and directors are noted in the table below.

	Years Ended December 31	
	2020	2019
Short-term employee benefits	**$ 4,295**	$ 6,202
Share-based compensation	**4,080**	9,188
Termination payments	**—**	2,208
Total compensation for key management personnel	**$ 8,375**	$ 17,598

22. CAPITAL MANAGEMENT

The Company's capital management objective is to maintain financial flexibility and sufficient sources of liquidity to execute its capital programs, while meeting short and long-term commitments. Baytex strives to actively manage its capital structure in response to changes in economic conditions. At December 31, 2020, the Company's capital structure was comprised of shareholders' capital, long-term notes, trade and other receivables, trade and other payables and the credit facilities.

During 2020, Baytex took additional action to protect financial liquidity in response to lower oil prices and the global economic instability related to COVID-19. The Company's 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. Baytex remains committed to cost saving initiatives which resulted in lower operating expenses and general administrative costs during 2020.

The capital intensive nature of Baytex's operations requires the maintenance of adequate sources of liquidity to fund ongoing exploration and development. Baytex's capital resources consist primarily of adjusted funds flow, available credit facilities and proceeds received from the divestiture of oil and gas properties. The Company's adjusted funds flow depends on a number of factors, including commodity prices, production and sales volumes, royalties, operating expenses, taxes and foreign exchange rates. In order to manage its capital structure and liquidity, Baytex may from time to time issue equity or debt securities, enter into business transactions including the sale of assets or adjust capital spending to manage current and projected debt levels. There is no certainty that any of these additional sources of capital would be available if required.

At December 31, 2020, Baytex was in compliance with all of the covenants contained in the Credit Facilities and had unused capacity of $367.2 million (December 31, 2019 - $523.8 million).

Baytex considers adjusted funds flow a key measure that provides a more complete understanding of operating performance and the Company's ability to generate funds for exploration and development expenditures, debt repayment, settlement of abandonment obligations and potential future dividends. Baytex eliminates settlements of abandonment obligations from cash flow from operations as the amounts can be discretionary and may vary from period to period depending on the Company's capital programs and the maturity of its operating areas. The settlement of abandonment obligations are managed through the 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 Baytex is able to provide a more meaningful measure of cash flow on a continuing basis.

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

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

	Years Ended December 31	
	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

The Company believes that net debt assists in providing a more complete understanding of its financial position and provides a key measure to assess liquidity. Net debt is calculated based on the principal amounts of the credit facilities and long-term notes outstanding, including trade and other payables, cash, and trade and other receivables. The principal amounts of the credit facilities and long-term notes outstanding are used in the calculation of net debt as these amounts represent the Company's 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.

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

	December 31, 2020	December 31, 2019
Credit facilities - principal	**$ 651,173**	$ 506,471
Long-term notes - principal	**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

PETROLEUM AND NATURAL GAS RESERVES AS AT DECEMBER 31, 2020

Baytex's year-end 2020 proved and probable reserves were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"), an independent qualified reserves evaluator. All of our oil and gas properties were evaluated in accordance with National Instrument 51-101 "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101") and the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") using the average commodity price forecasts and inflation rates of McDaniel, GLJ Petroleum Consultants ("GLJ") and Sproule Associates Limited ("Sproule") as of January 1, 2021.

Reserves associated with our thermal heavy oil projects at Gemini (Cold Lake) and Kerrobert have been classified as bitumen. Complete reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2020, which will be filed on or before March 31, 2021.

The following table sets forth our gross and net reserves volumes at December 31, 2020 by product type and reserves category. Please note that the data in the table may not add due to rounding.

Reserves Summary

Reserves Summary	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids (3) (mbbls)	Conventional Natural Gas (4) (mmcf)	Shale Gas (mmcf)	Total (5) (mboe)
Gross (1)									
Proved producing	20,404	23,473	19,917	1,144	64,938	31,669	43,384	97,321	120,057
Proved developed non-producing	61	38	1,997	160	2,255	639	15,072	473	5,485
Proved undeveloped	31,601	29,805	13,499	4,433	79,339	40,167	29,438	128,541	145,835
Total proved	52,067	53,316	35,412	5,737	146,532	72,475	87,894	226,334	271,378
Total probable	25,688	24,642	30,544	46,093	126,967	32,760	86,778	96,852	190,332
Proved plus probable	77,755	77,958	65,956	51,830	273,499	105,235	174,671	323,186	461,710
Net (2)									
Proved producing	19,106	17,445	18,404	1,027	55,983	23,635	40,568	72,440	98,452
Proved developed non-producing	59	28	1,895	152	2,135	504	13,080	350	4,877
Proved undeveloped	29,630	22,371	12,385	4,213	68,598	29,865	26,071	95,639	118,748
Total proved	48,795	39,844	32,684	5,393	126,716	54,003	79,270	168,429	222,077
Total probable	23,461	18,777	27,640	40,064	109,941	24,853	80,679	73,061	160,417
Proved plus probable	72,256	58,621	60,324	45,456	236,657	78,856	160,398	241,490	382,495

Notes:

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

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

(3) Natural Gas Liquids includes condensate.

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

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

Reserves Reconciliation

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

Proved Reserves – Gross Volumes [1] (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids [3] (mbbls)	Conventional Natural Gas [4] (mmcf)	Shale Gas (mmcf)	Total [5] (mboe)
December 31, 2019	60,619	55,562	51,311	11,799	179,291	77,939	104,506	234,162	313,674
Extensions	2,840	1,618	160	3,027	7,645	1,541	12,937	4,038	12,015
Technical Revisions [2]	(1,275)	1,780	2,462	(1,224)	1,743	(758)	9,360	7,225	3,749
Acquisitions	16	—	—	—	16	1	19	—	20
Dispositions	(15)	—	(5)	—	(20)	—	(38)	—	(26)
Economic Factors	(3,421)	(592)	(11,698)	(6,945)	(22,655)	(1,748)	(23,824)	(2,877)	(28,854)
Production	(6,698)	(5,052)	(6,818)	(920)	(19,488)	(4,499)	(15,066)	(16,213)	(29,200)
December 31, 2020	52,067	53,316	35,412	5,737	146,532	72,475	87,894	226,334	271,378

Probable Reserves – Gross Volumes [1] (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids [3] (mbbls)	Conventional Natural Gas [4] (mmcf)	Shale Gas (mmcf)	Total [5] (mboe)
December 31, 2019	31,218	24,139	37,805	53,743	146,905	35,654	99,816	99,739	215,818
Extensions	(1,937)	1,291	244	696	294	908	(11,371)	5,283	187
Technical Revisions [2]	(3,643)	(648)	(1,634)	(366)	(6,291)	(3,954)	(10,854)	(6,929)	(13,208)
Acquisitions	3	—	—	—	3	—	3	—	4
Dispositions	(92)	—	(4)	—	(96)	(4)	(348)	—	(158)
Economic Factors	139	(141)	(5,867)	(7,980)	(13,849)	157	9,531	(1,240)	(12,311)
Production	—	—	—	—	—	—	—	—	—
December 31, 2020	25,688	24,642	30,544	46,093	126,967	32,760	86,778	96,852	190,332

Proved Plus Probable Reserves – Gross Volumes [1] (Forecast Prices)

	Light and Medium Oil (mbbls)	Tight Oil (mbbls)	Heavy Oil (mbbls)	Bitumen (mbbls)	Total Oil (mbbls)	Natural Gas Liquids [3] (mbbls)	Conventional Natural Gas [4] (mmcf)	Shale Gas (mmcf)	Total [5] (mboe)
December 31, 2019	91,837	79,701	89,116	65,542	326,196	113,592	204,323	333,901	529,492
Extensions	903	2,909	404	3,723	7,939	2,449	1,565	9,320	12,202
Technical Revisions [2]	(4,917)	1,132	827	(1,590)	(4,548)	(4,712)	(1,494)	296	(9,460)
Acquisitions	19	—	—	—	19	1	22	—	24
Dispositions	(107)	—	(8)	—	(116)	(4)	(386)	—	(184)
Economic Factors	(3,282)	(733)	(17,565)	(14,925)	(36,505)	(1,592)	(14,293)	(4,118)	(41,165)
Production	(6,698)	(5,052)	(6,818)	(920)	(19,488)	(4,499)	(15,066)	(16,213)	(29,200)
December 31, 2020	77,755	77,958	65,956	51,830	273,499	105,235	174,671	323,186	461,710

Notes:

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

(2) Positive and negative revisions in heavy oil, bitumen, light and medium oil and tight oil are due to variations in performance versus previous forecasts in our Viking, Eagle Ford, Peace River and Lloydminster assets. Technical revisions for conventional natural gas are a combination of performance revisions in our Deep Basin assets and performance revisions for solution gas (classified as conventional natural gas) from our light and heavy oil properties. Positive revisions for shale gas are attributed to improved performance in the Duvernay and Eagle Ford assets.

(3) Natural gas liquids include condensate.

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

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

Future Development Costs

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

Future Development Costs ($ millions)	Proved Reserves	Proved Plus Probable Reserves
2021	276	283
2022	439	491
2023	477	560
2024	432	538
2025	420	580
Remainder	50	1,153
Total FDC undiscounted	2,094	3,606

F&D and FD&A Costs – including future development costs

Based on the evaluation of our petroleum and natural gas reserves prepared by McDaniel, the efficiency of our capital program is summarized in the following table.

millions except for per boe amounts	**2020**	**2019**	**2018**	**3 Year**
Proved plus Probable Reserves				
Finding & Development Costs				
Exploration and development expenditures	$280.3	$552.3	$495.7	$1,328.3
Net change in Future Development Costs	($705.9)	$96.7	$132.3	($476.8)
Gross Reserves additions (mmboe)	(38.4)	39.8	31.2	32.6
F&D Costs ($/boe)	$11.08	$16.30	$20.11	$26.09
Finding, Development & Acquisition (“FD&A”) Costs				
Exploration and development expenditures and net acquisitions	$280.2	$554.5	$2,099.6	$2,934.2
Net change in Future Development Costs	($709.3)	$79.9	$1,064.5	$435.1
Gross Reserves additions (mmboe)	(38.6)	38.6	123.9	123.9
FD&A Costs ($/boe)	$11.12	$16.42	$25.55	$27.19
Proved Reserves				
Finding & Development Costs				
Exploration and development expenditures	$280.3	$552.3	$495.7	$1,328.3
Net change in Future Development Costs	($464.4)	($90.4)	$117.4	($437.4)
Gross Reserves additions (mmboe)	(13.1)	35.8	17.5	40.2
F&D Costs ($/boe)	$14.06	$12.92	$35.05	$22.18
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$280.2	$554.5	$2,099.6	$2,934.2
Net change in Future Development Costs	($464.4)	($107.2)	$987.4	$415.8
Gross Reserves additions (mmboe)	(13.1)	34.7	88.4	110.0
FD&A Costs ($/boe)	$14.07	$12.88	$34.91	$30.44
Proved Developed Producing Reserves				
Finding & Development Costs				
Exploration and development expenditures	$280.3	$552.3	$495.7	$1,328.3
Gross Reserves additions (mmboe)	7.7	42.5	31.3	81.3
F&D Costs ($/boe)	$36.63	$13.04	$15.82	$16.33
Finding, Development & Acquisition Costs				
Exploration and development expenditures and net acquisitions	$280.2	$554.5	$2,099.6	$2,934.2
Gross Reserves additions (mmboe)	7.6	42.5	63.7	113.9
FD&A Costs ($/boe)	$36.64	$13.04	$32.95	$25.76

Reserves Life Index

The following table sets forth our reserves life index, which is calculated by dividing our proved and proved plus probable reserves at year-end 2020 by annualized Q4/2020 production.

		Reserves Life Index (years)	
	Q4/2020 Production	Proved	Proved Plus Probable
Crude Oil and NGL (bbl/d)	57,788	10.4	18.0
Natural Gas (mcf/d)	76,116	11.3	17.9
Oil Equivalent (boe/d)	70,475	10.5	17.9

Forecast Prices and Costs

The following table summarizes the forecast prices used in preparing the estimated reserves volumes and the net present values of future net revenues at December 31, 2020. The estimated future net revenue to be derived from the production of the reserves is based on the following average of the price forecasts of McDaniel, GLJ and Sproule as of January 1, 2020.

Year	WTI Crude Oil US$/bbl	Edmonton Light Crude Oil $/bbl	Western Canadian Select $/bbl	Henry Hub US$/MMbtu	AECO Spot $/MMbtu	Inflation Rate %/Yr	Exchange Rate $US/$Cdn
2020 act.	39.20	45.00	35.35	2.05	2.25	0.2	0.745
2021	47.17	55.76	44.63	2.83	2.78	0.0	0.768
2022	50.17	59.89	48.18	2.87	2.70	1.3	0.765
2023	53.17	63.48	52.10	2.90	2.61	2.0	0.763
2024	54.97	65.76	54.10	2.96	2.65	2.0	0.763
2025	56.07	67.13	55.19	3.02	2.70	2.0	0.763
2026	57.19	68.53	56.29	3.08	2.76	2.0	0.763
2027	58.34	69.95	57.42	3.14	2.81	2.0	0.763
2028	59.50	71.40	58.57	3.20	2.87	2.0	0.763
2029	60.69	72.88	59.74	3.26	2.92	2.0	0.763
2030	61.91	74.34	60.93	3.33	2.98	2.0	0.763
Thereafter		Escalation rate of 2.0%				2.0	0.763

Net Present Value of Reserves (1) (Forecast Prices and Costs)

The following table summarizes the McDaniel estimate of the net present value before income taxes of the future net revenue attributable to our reserves.

Reserves at December 31, 2020 ($ millions, discounted at)	0%	5%	10%	15%
Proved developed producing	1,089	1,203	1,118	1,018
Proved developed non-producing	69	59	51	46
Proved undeveloped	2,221	1,443	972	671
Total proved	3,379	2,704	2,141	1,735
Probable	3,374	1,837	1,138	771
Total Proved Plus Probable (before tax)	6,753	4,542	3,279	2,505

Note:

(1) Includes abandonment, decommissioning and reclamation costs for all producing and nonproducing wells and facilities.

Net Asset Value (Forecast Prices and Costs)

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

The following table sets forth our net asset value as at December 31, 2020.

($ millions, except per share amounts, discounted at)	5%	10%	15%
Net present value of proved plus probable reserves (1)	4,542	3,279	2,505
Undeveloped land holdings (2)	130	130	130
Net Debt	(1,848)	(1,848)	(1,848)
Net Asset Value	2,824	1,561	787
Net Asset Value per Share (3)	5.03	2.78	1.40

Notes:

(1) Includes abandonment, decommissioning and reclamation costs for all producing and nonproducing wells and facilities.
(2) The value of undeveloped land holdings generally represents the estimated replacement cost of our undeveloped land.
(3) Based on 561.2 million common shares outstanding as at December 31, 2020.

Advisory Regarding Oil and Gas Information

The reserves information contained in this report has been prepared in accordance with NI 51-101. Complete NI 51-101 reserves disclosure will be included in our Annual Information Form for the year ended December 31, 2020, which will be filed on or before March 31, 2021. Listed below are cautionary statements that are specifically required by NI 51-101:

- *The term barrels of oil equivalent ("boe") may be misleading, particularly if used in isolation. A boe conversion ratio of six thousand cubic feet of natural gas to one boe (6 mcf/bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value.*

- *With respect to finding and development costs, the aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.*

- *This report contains estimates of the net present value of our future net revenue from our reserves. Such amounts do not represent the fair market value of our reserves.*

Throughout this report, "oil and NGL" refers to heavy oil, bitumen, light and medium oil, tight oil, condensate and natural gas liquids ("NGL") product types as defined by NI 51-101. The following table shows Baytex's disaggregated production volumes for the three and twelve months ended December 31, 2020. The NI 51-101 product types are included as follows: "Heavy Oil" - heavy oil and bitumen, "Light and Medium Oil" - light and medium oil, tight oil and condensate, "NGL" - natural gas liquids and "Natural Gas" - shale gas and conventional natural gas.

	Three Months Ended December 31, 2020					Twelve Months Ended December 31, 2020				
	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)	Heavy Oil (bbl/d)	Light and Medium Oil (bbl/d)	NGL (bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (boe/d)
Canada – Heavy										
Peace River	10,918	9	14	13,295	13,157	9,853	7	12	11,630	11,810
Lloydminster	10,807	8	—	1,541	11,072	11,289	12	—	1,346	11,525
Canada - Light										
Viking	—	13,524	127	10,044	15,326	—	17,658	113	11,058	19,614
Duvernay	—	1,138	572	1,929	2,031	—	803	432	1,634	1,507
Remaining Properties	—	533	651	15,309	3,736	—	623	668	17,131	4,147
United States										
Eagle Ford	—	14,356	5,131	33,999	25,154	—	17,953	6,116	42,665	31,179
Total	21,725	29,568	6,495	76,116	70,475	21,142	37,056	7,340	85,463	79,781

This report discloses per boe 30-day initial production volumes for two wells drilled in the Pembina Duvernay. The disaggregated 30-day initial production volumes for the 10-16 well were 885 bbl/d Light and Medium Oil, 279 bbl/d NGL and 750 Mcf/d Natural Gas and for the 11-16 well were 601 bbl/d Light and Medium Oil, 195 bbl/d NGL and 522 Mcf/d Natural Gas.

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

Finding and development costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on exploration and development activities in the year by the change in reserves from the prior year for the reserve category.

Finding, development and acquisition costs are calculated on a per boe basis by dividing the aggregate of the change in future development costs from the prior year for the particular reserve category and the costs incurred on development and exploration activities and property acquisitions (net of dispositions) in the year by the change in reserves from the year for the reserve category

Net asset value has been calculated based on the estimated net present value of all future net revenue from our reserves, before income taxes, as estimated by McDaniel effective December 31, 2020, plus the estimated value of our undeveloped land holdings, less net debt.

Reserve life index means the reserves for the particular reserve category divided by annualized 2020 fourth quarter production.

Notice to United States Readers

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

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

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

ABBREVIATIONS

AECO	the natural gas storage facility located at Suffield, Alberta
bbl	barrel
bbl/d	barrel per day
*boe**	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
COSO	Committee of Sponsoring Organizations of the Treadway Commission
GAAP	generally accepted accounting principles
GJ	gigajoule
GJ/d	gigajoule per day
IAS	International Accounting Standard
IASB	International Accounting Standards Board
IFRS	International Financial Reporting Standards
LLS	Louisiana Light Sweet
mbbl	thousand barrels
*mboe**	thousand barrels of oil equivalent
mcf	thousand cubic feet
mcf/d	thousand cubic feet per day
mmBtu	million British Thermal Units
mmBtu/d	million British Thermal Units per day
mmcf	million cubic feet
mmcf/d	million cubic feet per day
NGL	natural gas liquids
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
TSX	Toronto Stock Exchange
WCS	Western Canadian Select
WTI	West Texas Intermediate

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

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Export Development Canada
National Bank of Canada
Royal Bank of Canada
The Toronto-Dominion Bank
Wells Fargo Bank

RESERVES ENGINEERS

McDaniel & Associates Consultants Ltd.

TRANSFER AGENT

Odyssey Trust Company

EXCHANGE LISTING

Toronto Stock Exchange
Symbol: **BTE**

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